Agenda
Reliability and Security Technical Committee

March 9, 2022 | 11:00 a.m.–4:30 p.m. Eastern Time
Virtual via WebEx

Attendee WebEx Link: Join Meeting

Call to Order

NERC Antitrust Compliance Guidelines and Public Announcement*

Introductions and Chair's Remarks

Regular Agenda

1. **Nominating Subcommittee Member Election* – Approve -** Chair Ford

   Per the RSTC Charter, the Nominating Subcommittee (NS) will consist of seven (7) members (the RSTC Vice-Chair and six (6) members drawing from different sectors and at-large representatives). Apart from the Vice-Chair, members of the RSTC Executive Committee (RSTC EC) shall not serve on the RSTC NS. The NS members are nominated by the RSTC chair and voted on by the full RSTC membership. The term for members of the NS is one (1) year. Nominations were sought February 11-18, 2022 for the NS and recommended candidates were selected by the RSTC Chair in consultation with the RSTC Executive Committee. The recommended candidates are:

   - Truong Le
   - William Allen
   - Patrick Doyle
   - Wayne Guttormson
   - Monica Jain
   - John Stephens

2. **6 GHz Task Force (6GHZTF) – Information** – Jennifer Flandermeyer, 6 GHzTF Chair

   In December 2021, the NERC RSTC established a task force to evaluate the issues associated with the Federal Communications Commission order that opened the 6 GHz band of radio spectrum to unlicensed users. Furthermore, the task force is charged with providing recommendations. In support of these efforts, the 6GHZTF is conducting a voluntary survey. The Task Force is requesting industry participation through the RSTC member companies and any additional participants from the Sectors they represent. The survey purpose is the first attempt to assess penetration of 6 GHz usage or extent of condition related to Bulk Power System impacts.

3. **E-ISAC Cyber Threat Landscape Brief– Information** – Matt Duncan

   Mr. Duncan will provide an update on the latest information on cyber threats from the E-ISAC.

4. **Energy Reliability Assessments Task Force (ERATF) Standard Authorization Request (SAR)* – Information** – Peter Brandien, ERATF Chair

   The ERATF is assessing 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 held an Industry Workshop on February 16, 2022 and will provide an update to the RSTC.

5. **Reliability Guideline: DER Forecasting Practices and Relationship to DER Modeling for BPS Planning Studies* –– Approve -** Shayan Rizvi, SPIDERWG Chair | Wayne Guttormson, Sponsor

   The SPIDERWG developed the Reliability Guideline: DER Forecasting Practices and Relationship to DER Modeling for BPS Planning Studies and posted it for a 45-day comment period. The SPIDERWG has addressed comments and made conforming revisions to the document. The SPIDERWG is seeking RSTC approval of the Reliability Guideline. If approved, the Reliability Guideline will be posted on the RSTC Reliability and Security Guidelines web page for industry use.

6. **White Paper: BPS Reliability Perspectives for Distributed Energy Resource Aggregators** - **Request RSTC Reviewers** - Shayan Rizvi, SPIDERWG Chair | Wayne Guttormson,

   This white paper provides bulk power system (BPS) reliability perspectives and considerations regarding distributed energy resource (DER) aggregation in light of Federal Energy Regulatory Commission (FERC) Order No. 2222, which introduces the concept of DER aggregation in wholesale electricity markets. The SPIDERWG is seeking RSTC members to review and provide comment on the white paper.

7. **White Paper: NERC Reliability Standards Review- Request RSTC Reviewers** - Shayan Rizvi, SPIDERWG Chair | Wayne Guttormson, Sponsor

   The increasing penetration of DERs is already having an impact on BPS planning, operations, and design, and it is paramount that NERC Reliability Standards remain effective and efficient in ensuring an adequate level of reliability for the BPS. As a result, the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) has evaluated the current body of NERC Reliability Standards and the requirements within those standards for their applicability and effectiveness to remain relevant with increasing levels of DERs. This white paper details the findings of the SPIDERWG review and makes recommendations for actions that should be taken to address identified issues. The SPIDERWG is seeking RSTC members to review and provide comment on the white paper.

8. **Forum and Group Reports – Information**

   a. North American Generator Forum* – Allen Schriver

   b. North American Transmission Forum* – Roman Carter

9. RSTC 2022 Calendar Review – Stephen Crutchfield

2022 Meeting Dates	Time	Location	Hotel
June 7, 2022 June 8, 2022	Please reserve entirety of both days	In person, location TBD	TBD
September 13, 2022 September 14, 2022	Please reserve entirety of both days	Atlanta	Grand Hyatt Buckhead
December 6, 2022 December 7, 2022	Please reserve entirety of both days	Virtual	Virtual

10. 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.

Nominating Subcommittee Member Election

Action
Approve

Summary
Per the RSTC Charter, the Nominating Subcommittee (NS) will consist of seven (7) members (the RSTC Vice-Chair and six (6) members drawing from different sectors and at-large representatives). Apart from the Vice-Chair, members of the RSTC Executive Committee (RSTC EC) shall not serve on the RSTC NS. The NS members are nominated by the RSTC chair and voted on by the full RSTC membership. The term for members of the NS is one (1) year. Nominations were sought February 11-18, 2022 for the NS and recommended candidates were selected by the RSTC Chair in consultation with the RSTC Executive Committee.

6 GHz Task Force (6GHZTF)

Action

Information

Summary

In December 2021, the NERC RSTC established a task force to evaluate the issues associated with the Federal Communications Commission order that opened the 6 GHz band of radio spectrum to unlicensed users. Furthermore, the task force is charged with providing recommendations. In support of these efforts, the 6GHZTF is conducting a voluntary survey. The Task Force is requesting industry participation through the RSTC member companies and any additional participants from the Sectors they represent. The survey purpose is the first attempt to assess penetration of 6 GHz usage or extent of condition related to bulk power system impacts.

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6 GHz Task Force Update

NERC Reliability and Security Technical Committee
March 2022

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Background Refresher

- In April 2020, the Federal Communications Commission (FCC) issued a Report and Order that partially opened the 6 GHz band of radio spectrum to unlicensed users.
- The sharing of this band of radio spectrum would introduce harmful interference with Bulk Power System operations.
- Furthermore, there is a pending Notice of Further Proposed Rulemaking with the FCC to fully open the 6 GHz band to unlicensed use and cause additional harmful interference to proliferate in this radio spectrum band.

6 GHz Task Force Scope

The 6GHz Task Force (6GHzTF) will provide recommendations to the NERC RSTC as follows:

1. **Determine scope of issue (e.g., limited to 6 GHz, relationship to other telecommunications items, etc.)**
2. Gather information related to risk of harmful interference in the 6 GHz spectrum.
    a. **Identify penetration and Bulk Power System users relying on 6 GHz.**
    b. Reach to industry for input on potential readiness issues (e.g., trade associations, membership organization, compliance forums, registered entities, etc.).
    c. Initiate or request industry information related to current harmful interference experience.
    d. Identify potential mitigation strategies.
3. Evaluate options for industry outreach.
4. Develop suggested recommendations related to the issue.

Survey Introduction

- The 6GHzTF, in support of the scope and efforts, is introducing a voluntary survey.
- The Task Force is requesting industry participation through the RSTC member companies and any additional participants from the Sector companies represented by RSTC members.
- The survey purpose is the first attempt to assess penetration of 6 GHz usage or extent of condition related to Bulk Power System impacts.

Survey Questions

- Q1: Please select your company's registration (check all that apply).
  - BA, GO, GOP, RC, RP, TO, TOP, TP
- Q2: What is 6 GHz used for (check all that apply)?
  - Not used at all
  - SCADA
  - Teleprotection
  - Corporate Communication
  - Nuclear
  - Control Centers
  - Other (comment box)

Survey Questions

- Q3: What percent of your company's 6 GHz paths are critical to grid/BPS? Note: Do not include local area transmission, radial, etc. (single choice)
  - 0 – 25%
  - 26 – 50%
  - 51 – 75%
  - Greater Than 75%
- Q4: Do you consider your operations to be a small, medium or large user of 6 GHz? (single choice)
  - Small: 1 – 5 Paths
  - Medium: 6 – 24 Paths
  - Large: 25+ Paths

Survey Questions

- Q5: How does your company use 6 GHz for ***Data*** (single choice)
  - Primary Communication
  - Backup Communication
  - Both Primary and Backup Communication
  - N/A
- Q6: How does your company use 6 GHz for ***Voice*** (single choice)
  - Primary Communication
  - Backup Communication
  - Both Primary and Backup Communication
  - N/A

Survey Questions

- Q7: If applicable, has your company performed an impact assessment in response to the FCC Report and Order? If applicable, please share high-level findings or preliminary assessment finds (single choice and comment box)
  - Yes
  - No
  - Comment Box
- Q8: Has your company performed any testing to identify potential impact of harmful interference? (single choice)
  - Yes
  - No

Survey Questions

- Q9: Has your company discussed mitigating actions? (single choice)
  - Yes, have discussed and taking action
  - Yes, have discussed and plan in place
  - Yes, have discussed and planning in progress
  - No
- Q10: Please provide Contact Information (optional). (comment box)

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Questions and Answers

Energy Reliability Assessments Task Force (ERATF)
Standard Authorization Request (SAR)

Action
Endorse

Summary
The ERATF is assessing 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 held an Industry Workshop on February 16, 2022 and will provide an update to the RSTC.

Reliability Guideline: DER Forecasting Practices and Relationship to DER Modeling for BPS Planning Studies

Action
Endorse

Summary
The SPIDERWG developed the Reliability Guideline: DER Forecasting Practices and Relationship to DER Modeling for BPS Planning Studies and posted it for a 45-day comment period. The SPIDERWG has addressed comments and made conforming revisions to the document. The SPIDERWG is seeking RSTC approval of the Reliability Guideline.

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Reliability Guideline

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

~~September 2021~~March 2022

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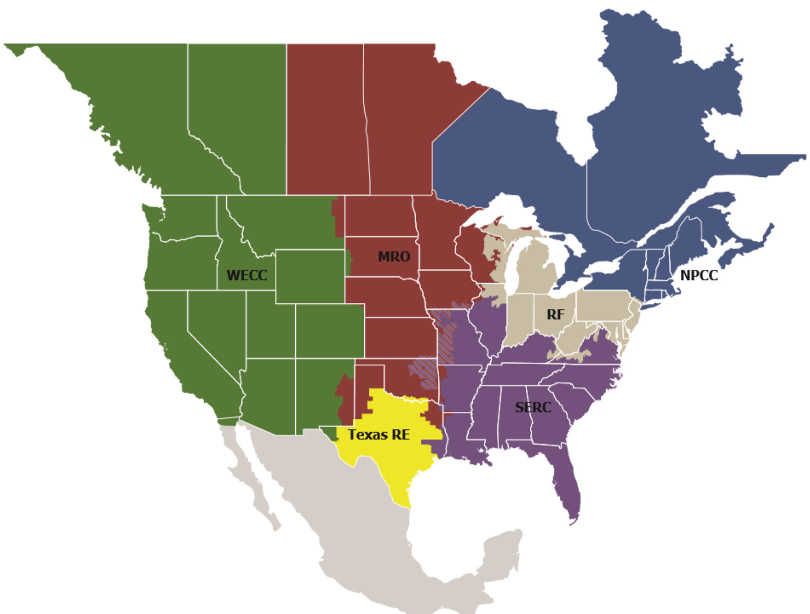
Preface

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 Reliability and Security Technical Committee (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

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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~~
- The Baseline Metrics survey above should focus on determining the extent by which industry practices have integrated the recommended DER forecasting practices. This includes,
  - Changes to data collection for use in forecasting
  - Changes to forecasting practices in industry
  - Changes in Load Forecast Uncertainty by performing a DER forecast
  - Changes in expected error of current forecasting practices by including DER information
  - Changes in planning assessment inputs and results for future year cases
  - Comparison of Realized DER values from previous year forecasts.

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~~Interconnection-wide planning 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 consistent with ~~reasonable accuracy~~the study assumptions 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 load 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

[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 refers 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 captured in a forecast by projection or scenario studies.

this data is not ~~of high quality~~accurate, the ~~projection, if used as the forecasted values,~~projections will ~~provide misleading, useless~~lead to inaccurate results.

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 their Resource Planners (RPs) to discuss forecasting of DER in their region.
- RPs should coordinate with other RPs in their service territory to ensure resources, inclusive of DER, are not being double counted.
- TPs and PCs should coordinate between their load forecasting and planning departments to ensure forecasts ~~meet the TP/PC~~align with their requirements, ~~namely for~~(i.e., the development of base cases~~,~~ ~~and~~) in order to ensure TPs/PCs have a ~~better~~clear understanding of forecast assumptions.
- TPs and PCs should ~~improve~~ have accurate data in their ~~relationship~~set of future year Interconnection-wide base cases, inclusive of DER values. TPs and PCs are encouraged to coordinate with ~~distribution~~various sources, including the DP and other forecasting entities ~~(e.g., DER developers, DER owners, and DPs) to gather data~~ , to ~~be~~ensure accurate data is used in ~~forecasting; or use a trustworthy outside entity that can perform DER forecasting for them.~~future year Interconnection-wide base cases.
- TPs and PCs should develop checklists as in **Figure 2~~.2.,~~5,** 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~~ see which projection is the basis of the DER values ~~for the~~ to be in alignment with their set of study assumptions. This may mean ~~a~~the TP and PC use forecasted ~~value is used~~values for ~~only~~ a portion of all studies ~~performed by the TP or PC~~they perform and a projection for others.

[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. In areas that do not perform IRPs, this process can be housed in a variety of different sections; however, the IRP process highlights some of the functions performed by Resource Planners (RPs), namely those related to the need to forecast information into future years. 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, some entities have moved from ~~this historic~~the previous 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 indicated in the figure, the uses of the "traditional" forecast were direct and singular. The move to a multi-use forecast, including uses in resource and transmission planning as in the figure, demonstrates that the DER forecast plays a role in the study of the bulk system. DER forecasts have higher sensitivity in distribution planning 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 of accurate DER values into ~~these numbers is critical for building predictive study~~transmission planning cases ~~that represent~~[5] is important as such cases are used to assess the ~~resources at future times.~~reliability of the bulk system; therefore, validated data should feed the DER forecasting process. This guideline covers both the forecasting practice assumptions and data quality checks that ~~goes~~go into these practices as they play a vital role in providing high quality BPS transmission studies~~.~~

[5] This is also true of including into resource planning cases.

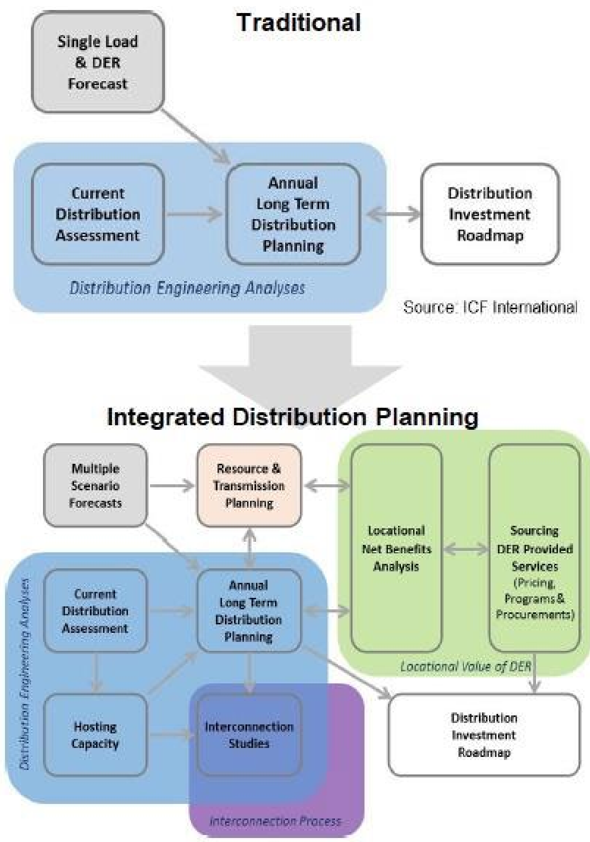

Figure I~~-~~.1: Move to Integrated Distribution Planning [Source: Minnesota Public Utilities Commission]

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~~noticeable when ~~looking at certain ways~~ determining which value of DER to enter in ~~DER values for~~to a 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 due to strong economic incentive, then ~~they may invest in their system to ensure reliability during~~the DER forecast should reflect this ~~period of growth~~tripling. 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~~impacts of the tripled DER growth, but ~~may only propose transmission upgrades~~will likely not use the value as a base case. Rather, it can be one of many scenarios to ~~developing their transmission system until such resources became more firm.~~study for future year assessments. The former ~~case~~decision is indicative of a forecast, while the latter, a projection. Additionally there are other terms used in this document found in a separate document[6], such as Utility-Scale Distributed Energy Resources (U-DER), which are provided by the SPIDERWG to be used in conjunction with all of their document including this Reliability Guideline.

Both transmission and distribution entities ~~are also moving towards another type of forecasting done at the utility, PC, or ISO/RTO level. Those entities~~in some regions 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~~typical resource procurement 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~~.. In doing so, entities are moving past the limitations of using a single data point for all transmission and distribution requirements. These changes allow for a forecast, inclusive of DER forecasts, to provide use in both transmission and distribution system planning, operation, and risk assessment.

~~If assuming any load~~Load forecasts ~~do not have DER associated~~for areas with ~~them~~known or expected DER growth that do not account for DER as separate from gross load will impact the results of simulations. Further, any correlations or changes to normalize load may not be correct[7]~~. 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~~ that area as the ~~loading of the feeder~~rates for gross load growth and ~~T&D bank will not explicitly track~~DER growth can occur at different rates. More challenges arise when considering historic and forecasted DER ~~for input into the TP's long-term planning assessments and their studies,~~growth in areas where DER data is not gathered or ~~other BPS-level studies.~~accounted for in forecast assumptions.

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~~it is important for TPs and PCs ~~may not be aware that tracking~~to track the capacity, vintage, and location of DER as these assumptions can often have ~~the same~~as large of an impact ~~in these~~on future ~~scenarios~~scenario study results as ~~the typical~~gross load forecasts can. 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~~.~~ and to ensure alignment between the study assumptions and forecast assumptions. Additionally, this document ~~aims to demonstrate~~describes 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.

[6] See the SPIDERWG Terms and Definitions Working Document available here: https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf

[7] 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~~TPs, PCs, and ~~DER forecasts provide adequate~~RPs rely on accurate values of existing and ~~reasonable projections for future studies within the context of comprehensive integrated~~projected Load (including DER) to perform resource planning and transmission 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~~under 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~~important, 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~~accurate 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[8] 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~~SPIDERWG has developed separate guidance on models developed to ~~design~~represent such equipment ~~to~~in the ~~current~~*Reliability Guideline: Bulk Power system Reliability Perspectives on*

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

the Adoption of *IEEE 1547* ~~standard and it is reasonable to consider that future DER installations will ride through voltage and frequency events~~ *2018*[9].

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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[10]. 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 Retail-Scale Distributed Energy Resources (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.

Data Gathering: Many of the inputs of a projection will either need to be synthesized or obtained through various data gathering mechanisms. Some of the data gathering mechanisms include surveys, monitoring, and telemetry infrastructure. Each have a relative accuracy in the way the data is collected, which can result in specific types of forecasting methods being unavailable. For instance, if there isn't a high level of confidence in the results of a customer survey, the forecasting entity might not want to choose a method that focuses on individual behavior but rather on a "generic" customer. Further, some mechanisms are embodied in NERC's Reliability Standards to allow transmission entities to gather information related to forecasting or modeling (as in the above section). A more detailed discussion is in Chapter 2; however, the key is having entities responsible for obtaining high quality, accurate information for use in forecasts (inclusive of DER forecasts) to develop future year models. Where data gathering proves insufficient, engineering judgement based projections can be used in a forecast yet are typically regarded as inexact.

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[11]. 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

[9] Document available: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Guideline_IEEE_1547-2018_BPS_Perspectives.pdf

[10] To understand the modeling of DER as U-DER and R-DER, see previous modeling guidance at the following links: ~~here~~https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Modeling_DER_in_Dynamic_Load_Models_-_FINAL.pdf, ~~here~~https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-08-18_-_FINAL.pdf~~, here, and~~ , https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_Data_Collection_for_Modeling.pdf, and ~~here~~https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

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[11] There are a variety of important factors (e.g., the power factor) in a load forecast and how load is attained for study; however, the full extent is out of scope for guidance related to DER forecasts.

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.[12]

Uncertainty in data: ~~As~~ There exists uncertainty with any 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[13] 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 production data that has a proven temporal correlation ~~to the power produced by the resource, shown in the~~with an associated simulated resource profile. Resource profiles provide installation specific or aggregate data to indicate 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 with shifting base case assumptions. In short, these profiles provide a way to ~~transfer~~convert capacity based projections into power production at a given time, which allows a TP to enter DER generation into their future cases. Many of the common resource profiles are “synthetic profiles” that convert weather data into a power conversion model for weather-dependent resources. Such methods are a key consideration available to planners in order to convert forecasted quantities, i.e., long-term weather conditions, into changes in power.

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 model 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

[12] 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

[13] 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.

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[14]. 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
	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.

[14] 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.

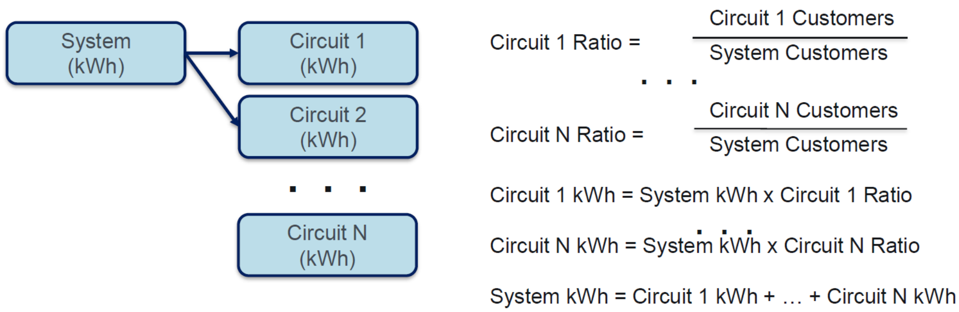

Figure 1. 1: Proportional Allocation Flowchart

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.[15]

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[16] 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 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.

[15] 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).
[16] 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

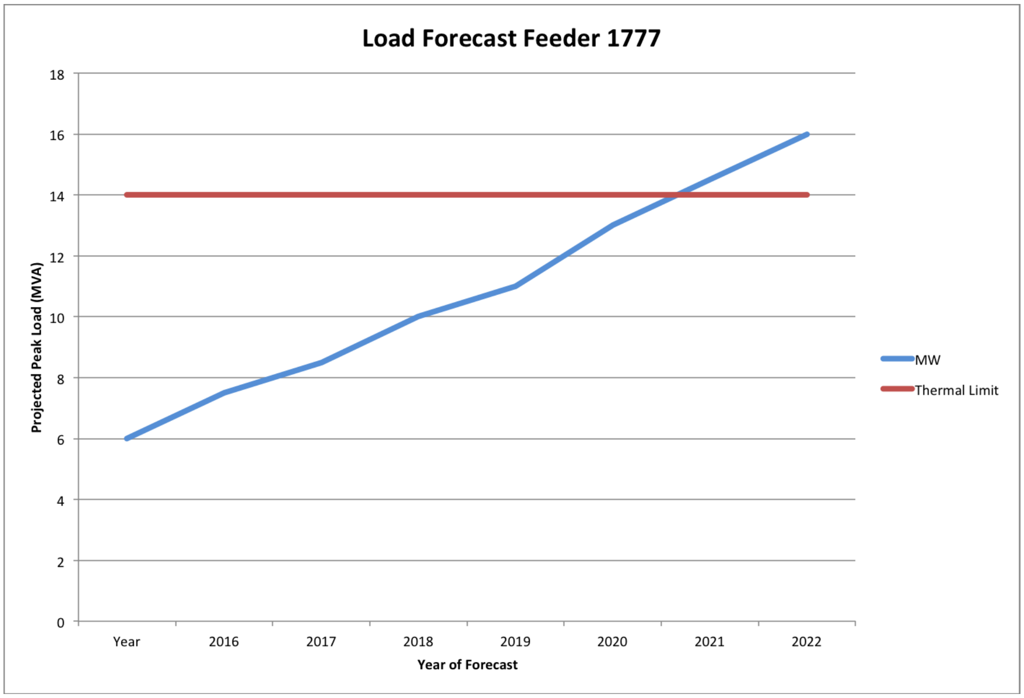

Figure 1.2: An Example of Peak Load Forecasting [Source: NREL]

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~~bottom 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~~.~~[17]. A few different types of methods are

[17] Entities can use these methods to forecast for on-peak or off-peak conditions for DER. To do so, entities need to ensure that the data used in the forecast method is in alignment with the desired outcome. That is, if forecasting for off-peak conditions the data used in the method chosen should be in alignment with an off-peak study.

described below[18], which include time series extrapolation, policy-based approaches, macroeconomic simulation, ~~bass~~Bass diffusion models, and adoption models. It is recommended that these methods be carefully reviewed for the goal, timing, and desired confidence level in the analysis being performed.

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~~sources 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[19].

[18] A comparison of these forecasting methods, and some guidance related to gathering data in support of a forecasting method can be found at various industry reports. Two such EPRI reports are Guidance on Solar PV Adoption Forecasting Methods for Distribution Planning. EPRI. Palo Alto, CA: 2018. 3002014724 Available here: https://www.epri.com/research/products/000000003002014724 and Data Sources and Considerations for Solar PV Adoption Forecasting: Guidance for Data Scientists and GIS Analysis. EPRI. Palo Alto, CA: 2018. 3002014725. Available here: https://www.epri.com/research/products/000000003002014725. Further, Table 2 of NREL's *An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions* compares some of these methods. Available here: https://www.nrel.gov/docs/fy19osti/72102.pdf

[19] 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.

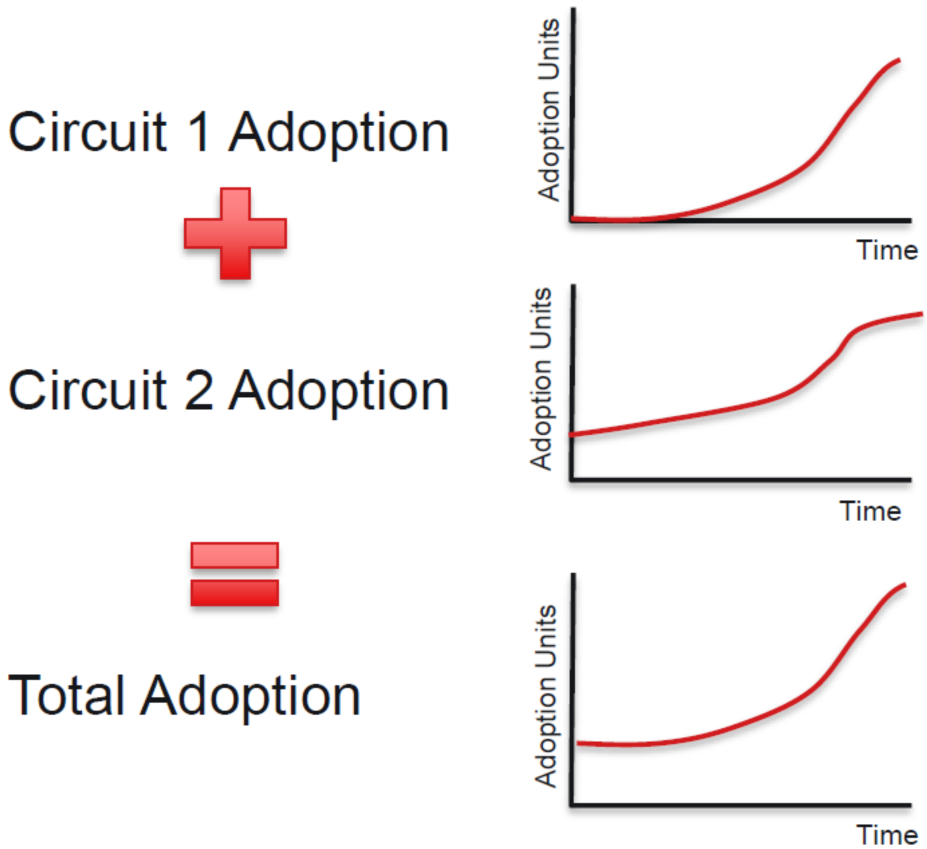

Figure 1.3: Adoption Model High Level Summary [Source: Itron]

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~~[20]~~: 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~~evolve; 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[21] 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.

~~[20] Guidance on Solar PV Adoption Forecasting Methods for Distribution Planning. EPRI. Palo Alto, CA: 2018. 3002014724~~

[21] NVEnergy's latest filings can be found online. Their 2021 IRP is available here: https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/recent-regulatory-filings/nve/irp/2021-irp-filings/NVE-21-06-IRP-VOL4.pdf

~~IID~~

Imperial Irrigation District (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 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[22] 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[23], 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.

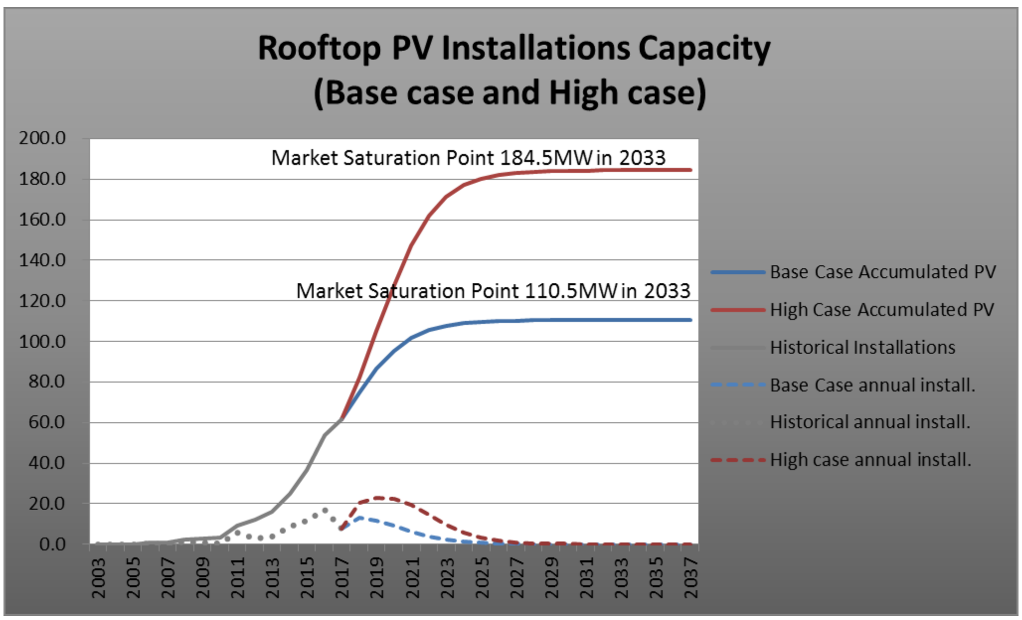

Figure 1.4: IID Projected PV forecast from 2018 Load Forecast

[22] These saturation points are limitations of capacity and are assumed values going into the forecast.

[23] ~~IID's 2018 Load Forecast can be found here~~ IID's load forecasting page is reachable at the following link: https://www.iid.com/energy/renewable-energy/integrated-resource-plan. The numbers in this document come from their 2018 IRP available here: https://www.iid.com/home/showpublisheddocument/9280/636927586520070000

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~~PNM~~

Public Service Company of New Mexico (PNM)

Like NVEnergy and IID, PNM does not receive state input for their forecasts, but rather completes their DER forecast internally[24]. 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.

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[25] developed by the California Energy Commission (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 California Public Utilities Commission (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

[24] PNM provides their full IRP reports, that include their internal DER forecast results, here: https://www.pnmforwardtogether.com/irp

[25] The forecasts by the CEC are available for download here: https://www.energy.ca.gov/data-reports/planning-and-forecasting

Supply-side DG in front of the customer meter	PTO Wholesale Distribution Access Tariff (WDAT)and CPUC Renewable Portfolios Standard (RPS) portfolio
Energy Efficiency[26]	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-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.

[26] 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.

Chapter 2: Forecasting Practices and MOD-031

NERC standard MOD-031[27] serves as the primary NERC standard associated with ~~DER~~ forecasting of future quantities. 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~~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~~power flow records.

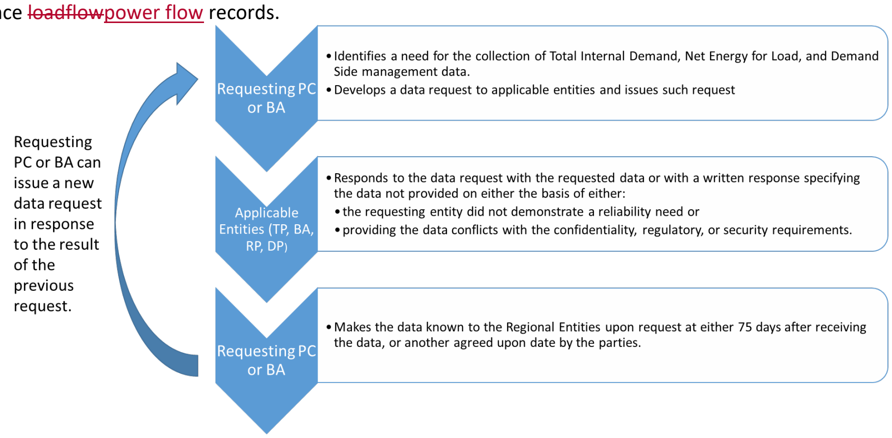


Figure 2.1: MOD-031 Logic Flowchart

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.

[27] MOD-031-3 available here: ~~https://www.nerc.com/pa/Stand/Reliability%20Standards/MOD-031-3.pdf~~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[28] 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.~~

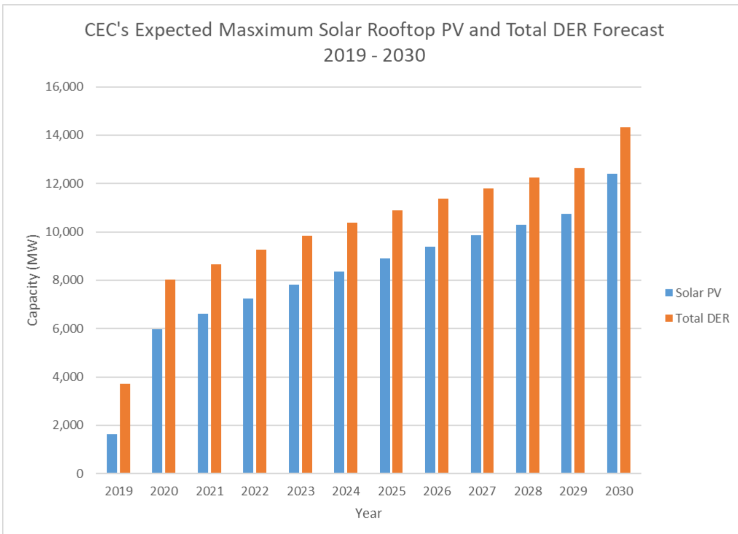
MOD-031 and Interconnection-wide Base Case Creation

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~~point. Interconnection-wide base cases follow the ~~PC (or TP~~same concept and are produced in ~~some studies)~~MOD-032, yet can ~~apply a method to in order to produce a result. These~~receive important validation of specific values under MOD-031. The assumptions ~~are~~decided on for each base case (produced by TPs and PCs under MOD-032 or different case creation procedures) can be validated by the forecasted values with the data under MOD-031. This is an important distinction for entities building future year cases as the values received under MOD-031 and MOD-032 should match assuming all things equal[29]. If using MOD-031 to ask for DER information, ~~an explicit~~a clear description of the item should be placed in the data request to ~~be clear that it is requesting~~ensure the desired data is understood and identified as DER to ensure clarity of the request.

~~For~~As a hypothetical example, if DER is not explicitly represented in the forecast, a PC ~~found~~might find that, in aggregate, their data request under MOD-031 resulted in a load value ~~of load~~ higher than the base case value used for the next year~~,~~. The PC then ~~the PC can~~must adjust ~~and validate their system-wide set up such that~~ the ~~base case represents such~~ load and DER values to account for the missing DER impact. 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~~then also must refine their system model to become more in line with the submitted data. ~~Outside sources can supplement the forecasted value~~PCs should also consider using data from trusted outside sources instead of ~~a~~their MOD-031 data ~~request.~~requests. As an example of supplemental data, Figure 2.2 shows the ~~California Energy Commission (~~CEC~~)~~ providing an expected solar PV rooftop forecast for public use~~, and should~~. Such data can be used to help refine the base case assumptions used for future case setups.

~~[28] Draft is available here [link if published draft/final]~~

[29] To clarify, if the assumptions driving the future year base case creation are also those chosen for the forecasted method, the two results of the quantity (i.e. a wide-spread MW value of Load) should be the same as represented in both the base case used in transmission planning and in the forecast used in resource planning.



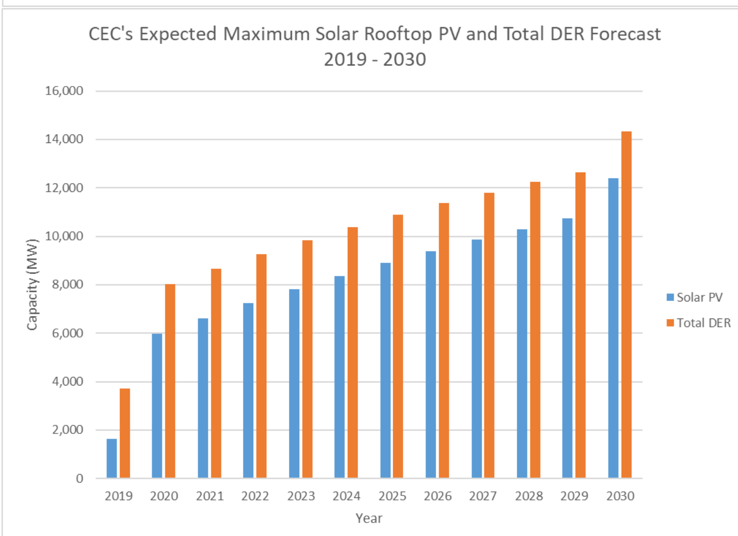


Figure 2.2 Example of Values to Build Base Cases

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~~This section highlights best practices ~~come to light throughout the various forecasting methods in Chapter 1, and current vehicle to pass forecasted~~for disaggregating DER into appropriate values ~~to the PC to build~~for building 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.

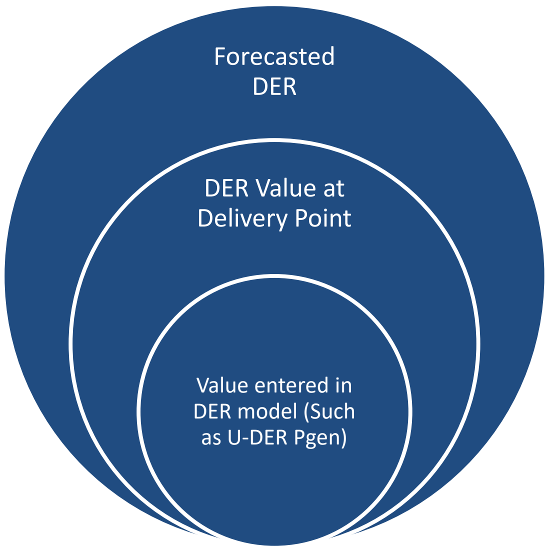


Figure 2.3: Disaggregation of DER into a Useful Study Value.

~~In order~~ One useful strategy for improving base case forecast assumptions is to ~~better accomplish~~build up the ~~task of entering high fidelity values in future base cases built by the PC, the TPs and PCs should improve their relationship~~relationships with distribution entities in order to ~~gather~~more easily get 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.~~for validating and interpreting the forecast values.. In the current list of NERC Registered Entities, the DP is the only functional entity that ~~contains~~may maintain a direct relationship with the DER associated with the distribution system they oversee. While some DPs may not have information from all DER owners at this time, this lack does not detract from the importance of providing accurate future aggregate DER values to be used in transmission level studies.

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[30] 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[31]. As their procedure forecasted the T-D operational profile, the location, capacity, and expected production from that capacity, APS was able to send to WECC the major values needed when adding DER into a future planning base case.

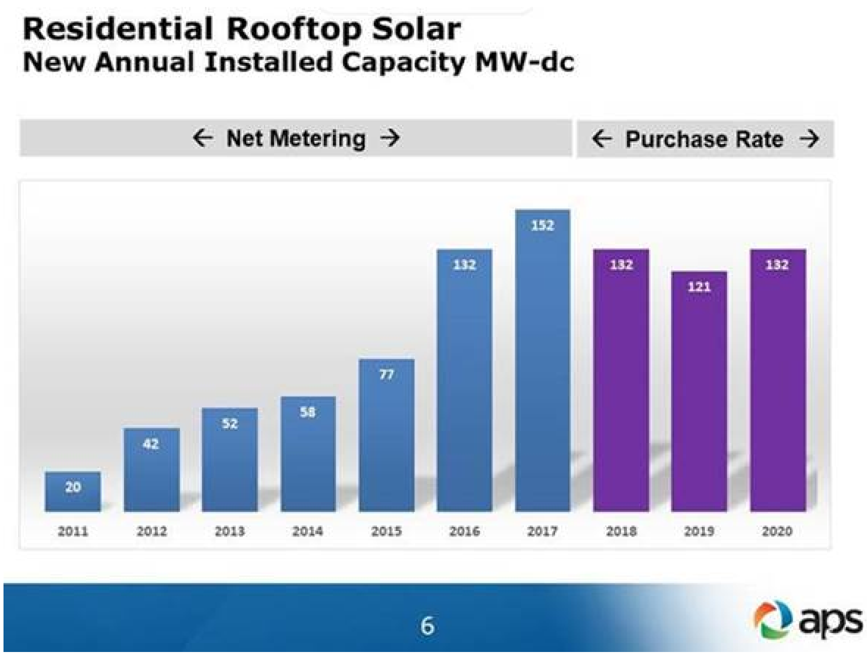


Figure 2.4: APS's Change in Annual Rooftop Solar Growth

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.

[30] 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.

[31] 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.

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 neighbors?
- 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, forecasts do not necessarily align between the distribution and transmission side of a T-D ~~perspective~~Interface. A DP may want to emphasize local factors that ~~accentuate larger~~contribute to more DER capacity projections ~~for use by the DP in~~when performing distribution planning studies; however, a TP/PC may want to emphasize growth across a larger geographic ~~projections~~area for use in their studies even if the growth simplifies local factors. 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~~kept in mind when creating 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~~Consider 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	Knowing the existing locations of DER, combined with forecasted locations from a larger geographic level allows the TP to compare to a

	schemes that may change the DER location.	smaller geographic level[32] and to 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.
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.[33]

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

[33] 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~~impact 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.[34] 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, as 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. Because of the many different operational characteristics of differing "types" of DER, it is recommended that consistent labeling of the data is included at all stages so all information is clearly understood by the entities. That is, from the distribution side of the T-D interface to the transmission side. 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

[34] 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.

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.

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.

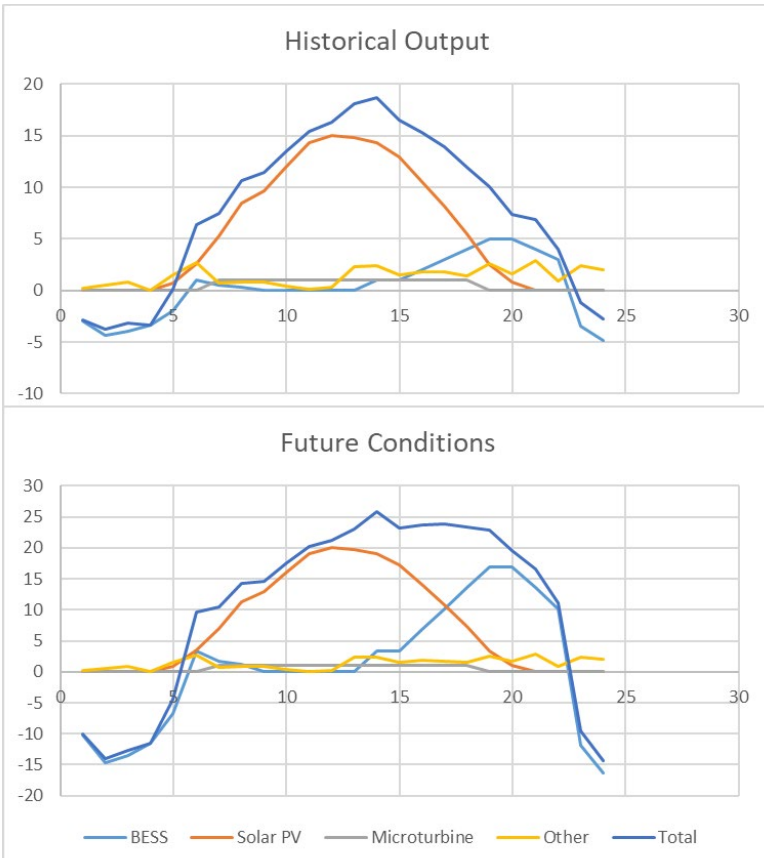


Figure 3.1: Example forecasting example at a T-D interface

Provided as an example, Figure ~~2~~3.1 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~~ISO-NE provided an example that ~~follows through~~highlights 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 forecasting 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~~1 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~~1 and allocate to their predefined dispatch zones.

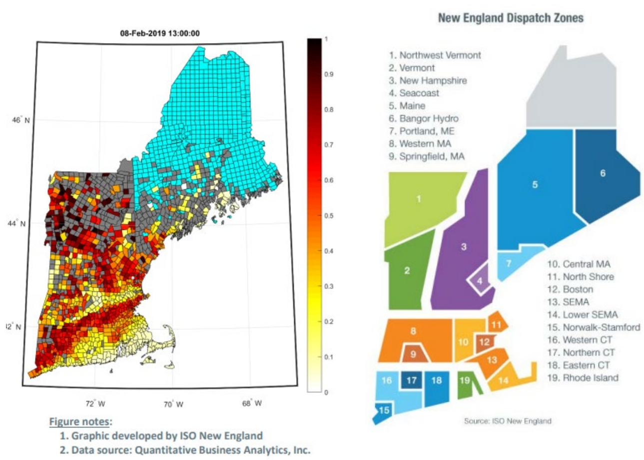


Figure 3.2: ISO-NE Geographic Distribution Breakdown

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.

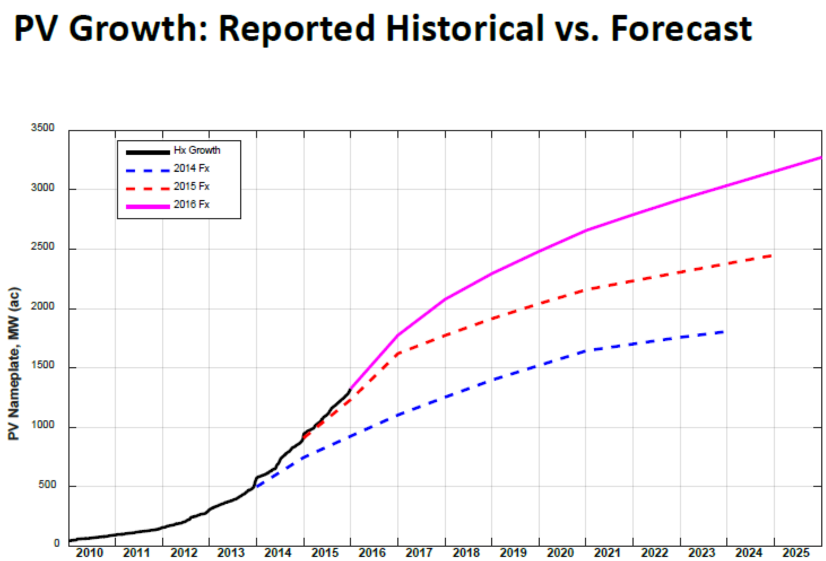


Figure 3.3: ISO-NE Future DER predictions from past forecasts.

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~~ SPDIERWG performed an ~~informal poll~~analysis of ~~SPIDERWG members,~~its membership's forecasting practices and 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~~From the SPIDERWG analysis of their own membership's practices, SPIDERWG identified the following:

1. ~~Entities that~~ Some entities manual checked[35] actuals against previous years' forecasts.

[35] Entities that manually checked their forecasts generally took their current year DER queue and compared it with the previous years' forecast to make changes to the forecasting procedures.

2. ~~Entities that~~ Some entities perform automated checking[36] of forecasts via playback into their procedure.
3. ~~Entities that~~ Some entities 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~~Based on SPIDERWG's analysis, 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 (~~their RPs~~)~~ to discuss forecasting of DER in their region.
- RPs should coordinate with other RPs in their service territory to ensure resources, inclusive of DER, are not being double counted.
- 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~~ have accurate data in their ~~relationship~~set of future year Interconnection-wide base cases, inclusive of DER values. TPs and PCs are encouraged to coordinate with ~~distribution~~various sources, including the DP and other forecasting entities ~~(e.g., DER developers, DER owners, and DPs) to gather data~~ , to ~~be~~ensure accurate data is used in ~~forecasting; or use a trustworthy outside entity that can perform DER forecasting for them.~~future year Interconnection-wide base cases.
- TPs and PCs should develop checklists as in Figure 2.~~2.~~5, 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~~ see which projection is the basis of the DER values ~~for the~~ to be in alignment with their set of study assumptions. This may mean ~~a~~the TP and PC use forecasted ~~value is used~~values for ~~only~~ a portion of all studies ~~performed by the TP or PC~~they perform and a projection for others.

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

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[36] Entities that performed automatic checking generally used a 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 is typically done as part of a larger effort to refine the forecasting procedures.

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
Michael Lombardi	~~Northeast Power Coordinating Council, Inc~~NPCC
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Shahrokh Akhlaghi	~~Southwest Power Pool~~SPP
Shannon Mickens	SPP
Irina Green	~~California ISO~~Guidehouse
Dan Kopin	VELCO
Hassan Ghoudjehbaklou	San Diego Gas and Electric
Evan Paull	~~Western Electric Coordinating Council~~ WECC
Deepak Ramasubramanian	~~Electric Power Research Institute~~EPRI
Parag Mitra	~~Electric Power Research Institute~~EPRI
Jose Cordova	EPRI
Steven Rymsha	SunRun Power
Laura Fedoruk	SunRun Power
Steven Coley	TVA
James Manning	North Carolina Electric Membership Corporation
John Pearson	ISO-NE
Bill ~~Quantance~~Quaintance (SPIDERWG Vice-Chair)	Duke Energy
Shayan Rizvi~~Kun Zhu~~ (SPIDERWG Chair and Verification Co-Lead)	~~MISO~~NPCC
Ryan Quint (SPIDERWG Coordinator)	North American Electric Reliability Corporation
John Skeath (SPIDERWG Coordinator)	North American Electric Reliability Corporation

Reliability Guideline	Reliability Guideline: DER Forecasting Practices and Relationship to DER Modeling for BPS Planning Studies
Instructions	**Please use this form to submit comments on the draft Reliability Guideline. Comments must be submitted within the review period below to John Skeath (John.Skeath@nerc.net) and Ryan Quint (Ryan.Quint@nerc.net) with the words "Reliability Guideline: DER Forecasting Practices and Relationship to DER Modeling for BPS Planning Studies Comments" in the subject line. Only comments submitted in this Microsoft Excel format will be accepted. Both general and specific comments should be provided within this form.** Comments may be submitted by individuals or organizations. Please provide the requested information in Row 6. If comments are submitted on behalf of multiple organizations, list all organizations in Row 6. Please provide the Industry Segment and Region (if applicable) in Rows 7 and 8 and provide the requested contact information in Rows 9 and 10. If you have any questions regarding this process, please contact Ryan Quint (Ryan.Quint@nerc.net) or John Skeath (John.Skeath@nerc.net)
Review Period	October 6, 2021 - November 20, 2021

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Edison Electric Institute	N/A	N/A	General Comment: EEI notes that the purpose of MOD-031 is 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" while MOD-032's purpose is to "establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system." The guidance contained in this Reliability Guideline seems to change the intended purpose of MOD-031, which is to aggregate load forecasts for resource planning, not transmission planning. This mixing of guidance from MOD-032 with MOD-031 is confusing and needs to be more clearly described to better explain why this is appropriate and consistent with the intended purposes of each Reliability Standard. While there needs to be a mechanism that obligates DER owners to supply needed DER specific information/data for planning purposes, this is not the proper platform to	This mixing of guidance from MOD-032 with MOD-031 is confusing and needs to be more clearly described to better explain why this is appropriate and consistent with the intended purposes of each Reliability Standard. While there needs to be a mechanism that obligates DER owners to supply needed DER specific information/data for planning purposes, this is not the proper platform to achieve that purpose.	Thank you for your comment. Text added in the section "MOD-031 and Interconnection-wide Base Case Creation" that clarifies the points made with respect to both MOD standards.
Edison Electric Institute			There are many terms that have not been defined within the document. While most these terms have been previously defined within other NERC SPIDERWG documents, they remain outside of the NERC Glossary of Terms. EEI suggests including the SPIDERWG Terms and Definitions Working Document (See https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf) along with any other terms used within this guideline that are not included in that document.	EEI suggests adding the SPIDERWG definitions and any additional definitions not currently included in the document.	Added reference to the SPIDERWG terms and definitions document and spelled out acronyms where applicable.
Edison Electric Institute	vi	115 - 116	The inclusion of Integrated Resource Plans (IRPs) within this guideline could cause some confusion for entities that are not required by their state to develop such a plan. While the information in the guideline regarding IRPs may be useful guidance for affected entities, the guideline should also be broad enough to also consider alternative for those who do not have similar regulatory obligations.	Suggest providing guidance that includes entities that are not obligated to develop IRPs.	Added text in the Introduction that clarifies for non-IRP areas.

Edison Electric Institute	vii	151 - 152	EEI suggests the following edits to the first recommendation to align with the responsibilities as defined by NERC's Compliance Registry: • TPs and PCs should attend and contribute to current forums where DER forecasting is discussed. Further, TPs and PCs should coordinate with **their** Resource Planners (RPs) to discuss forecasting of DER in their region. o **RPs should coordinate with other RPs in their area to ensure resources are not being double**	EEI suggests the following edits to the first recommendation to align with the responsibilities as defined by NERC's Compliance Registry.	Changes made based on proposed edit.
Edison Electric Institute	vii	153 - 155	EEI suggests the following edits to the second bullet: TPs and PCs should coordinate between their load forecasting and planning departments to ensure forecasts align with their requirements, (i.e., the development of base cases) in order to ensure TPs/PCs have a clear understanding of forecast assumptions.	Suggested edits.	Changes made as proposed
Edison Electric Institute	vii	156 - 158	EEI disagrees with the recommendation that TPs and PCs should be improving their relationships with DER developers and owners. Developing or improving relationships is subjective and unmeasurable. In addition, the responsibility for gathering needed resource information is the responsibility of the RP (noting that the RP may in some cases also be the TP or PC). We further note that depending on how a company is structured, TPs may not do load forecasting but instead gather that information from customers. In these situation, it is more difficult to obtain interconnection specific DER Information as directed in this guideline. For this reason, additional guidance should be provided on how best to address these types of challenges. While the following does not address this concern, it does better align with the functional obligations of the RP: *RPs should improve their relationship with DPs in order to gather data needed by TPs and PCs in order to allow for improved DER*	Suggested edits and changes to better align with the conditions and practices of all registered entities.	Altered text based on proposed change.
Edison Electric Institute	vii	159 - 160	It is unclear what the intent is for the fourth bulleted recommendation. Figure 2.2 does not contain checklists that might inform the industry. EEI asks that the reference to Figure 2.2 be corrected or revise the guideline to provide the intended checklist.	Request additional clarity to the fourth bullet, correct the reference to Fig.2.2 or provide the intended checklist.	The reference checklist is in Figure 2.5 and not 2.2. Clarity edits made.
Edison Electric Institute	vii	161 - 163	The fifth bulleted recommendation is not clear. EEI asks that consideration be given to rewording this recommendation to provide clearer direction to the industry.	EEI asks that consideration be given to rewording this recommendation to provide clearer direction to the industry.	Clarity edits made to emphasize the recommendation to TPs and PCs that a forecasted value may not be suitable for all types of studies and to align study assumptions with similar forecast/projection assumptions.

Edison Electric Institute	vii	168 - 177	As mentioned in our comments above, not all NERC registered entities operate in states that require IRPs. For this reason, we suggest that less focus be placed on state regulatory requirements and instead provide direction which is more generic and more useful to all NERC registered entities. From this perspective, the purpose of Transmission Planners is to assess the long-term reliability of their transmission planning area. As such, TPs need to coordinate with their RPs, GOs, DPs, TOs, TSPs and connected TPs in order to better understand the locational impacts of DERs, including both utility scale and areas where residential DERs might be impacts distribution loads. Guidance that recognizes that RPs, TOs and DPs are the entities who have the most accurate information on DERs impacts and changes and growth patterns under the responsible TP purviews as well as where areas where DERs are being planned over the TPs planning horizon should be the focus. While IRPs might factor into those insights, their relevance to DER modeling is not relevant to all NERC registered entities and should not	EEI suggests that less focus be placed on state regulatory requirements and instead provide direction which is more generic and more useful to all NERC registered entities.	Added text to assist in providing background similarities for areas that do not perform IRPs.
Edison Electric Institute	ix	189	While Figure I-1 shows distinct differences in the forecasting procedure, the document lacks a clear explanation of the processes necessary to understand those differences	EEI asks that additional clarity be added to Figure I-1.	Clarity edits made in the Introduction section based on comment.
Edison Electric Institute	ix	196 - 201	The discussion contained in this section where the guideline contrasts protections and forecasts in the context of DERs does not seem to add value. While this may be a point worth contrasting, additional language clarifying the intended purpose may be useful for those developing DER forecasts for their companies.	EEI asks that additional language clarifying the intended purpose may be useful for those developing DER forecasts for their companies.	Text altered to add clarifying language.
Edison Electric Institute	1	251 - 255	A distinction between DERs that are aggregated under Order 2222 and those that do not meet the definition of BES or are exclusively for local distribution may be beneficial here given the approach to developing effective forecast would be impacted by how the resources will be used	EEI asks for providing a distinction between DERs that are aggregated under Order 2222 and those that do not meet the definition of BES or intended exclusively for local distribution would be useful.	Thank you for your comment. The comment's concern on operational profiles of resources under DER aggregators (or not under an aggregator) are covered under the resource profile section in general guidance.
Edison Electric Institute	5	404	Line 404 (DER Forecasting Methods): While the identification of various DER forecasting methods is beneficial, the guideline would be enhanced with the inclusion of hyperlinks to industry white papers that describe in more detail the identified methods and industry successes through their use. Additionally, a comparison of the various modeling options listing pros and cons between the various options might also be helpful for entities seeking to improve their modeling methods. An example of this can be seen in the NREL document titled "an Overview of Distributed Energy Resources (DER) Interconnection: Current Practices and Emerging Solutions". See https://www.nrel.gov/docs/fy19osti/72102.pdf	1) The guideline would be enhanced with the inclusion of hyperlinks to industry white papers that describe in more detail the identified methods and industry successes through their use. 2) a comparison of the various modeling options listing pros and cons between the various options might also be helpful for entities seeking to improve their modeling methods	Thank you for your comment. Added link to documents describing the methods and comparisons where applicable.
Edison Electric Institute	8	456	Footnote 14: The EPRI reference document in this footnote should contain a hyperlink for easy use by the reader. EEI notes that this document has been made publicly available by EPRI	Add a hyperlink to the EPRI document.	Changes made based on comment.
Edison Electric Institute	10	527	On line 527 the acronym CEC is used but is not defined until Line 630 (i.e., California Energy Commission). Acronyms should be defined the first time they are used. EEI suggests defining CEC on line 527 and using CEC on line 630	CEC should be defined.	Change made as suggested in comment.

Edison Electric Institute	10	527	References such as the presentation titled "Demand Analysis Working Group (DAWG), Additional Achievable Energy Efficiency (AAEE) Process should be referenced within the guideline in order to provide additional detail and context.	DAWG, AAEE should be referenced in the document.	Added link to the CEC forecast page for reference.
Edison Electric Institute	10	543	CPUC should be spelled out in its first use.	CPUC should be spelled out in its first use	Change made as proposed.
Edison Electric Institute	12 & 13	574 & 603 to 614	The guideline states that the "MOD-031 serves as the primary NERC standard associated with DER forecasting", however, the SPIDERWG Reliability Standards Review white paper (See https://www.mro.net/MRODocuments/Whitepaper%20SPIDERWG%20Standards%20Review%2003092021.pdf) identifies concerns with MOD-031 implying that the Standard, as currently written, is not sufficient to allow PC to clearly identify "how much actual demand is on the system given the amount being served by embedded generation". (See page 16 of the white paper) EEI ask for clarification between of the discrepancies of the two documents be made.	Clarify the differences between this Guideline and the SPIDERWG white paper referenced.	The standard review white paper is currently under draft and is not approved. The section was removed as the SPIDERWG does not desire to reference unpublished other SPIDERWG works for approved guidance.
Edison Electric Institute	13	622	A period is missing between "the data under MOD-031" and "If using MOD-31".	minor edit	Change made as proposed
Edison Electric Institute	13	622 - 623	EEI suggests the following modification to the last sentence in this section for clarity: If using MOD-031 to ask for DER information, **clear description of the** item[s] **that are needed** should be placed in the data request to **ensure the desired data is understood and identified as** DER **specific data**.	suggested edits	Changes made based on suggested edit
Edison Electric Institute	13	625 - 632	EEI offers the following edits to clarify the paragraph contained in this section: 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. **In this circumstance the** PC **should consider** adjust**ing** and valida**ting** their system-wide set up **to more closely represent the anticipated load in** the base case. 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. **PCs should also consider using data from trusted o**utside sources **obtained outside of their MOD-031** data request. **As an example of this type of supplemental data,** Figure 2.2 shows **data from** the California Energy Commission (CEC) **that** provid**es their** expected solar PV rooftop forecast for public use.	Suggested edits	Changes made based on suggested edits.
Edison Electric Institute	15	650 - 651	EEI does not agree with the statement that "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". In reviewing the relationships identified in the last approved NERC Functional Model, we find no role for TPs and PCs to gather data from "distribution entities". Moreover, there are no obligations by distribution entities to provide such data to TPs and PCs. We suggest that TPs and PCs work with DPs in order to better understand and interpret forecasted values for DERs and load since it is the DP who has the relationships with interconnected DERs.	We offer some suggested changes that we understand more closely align entity practices.	Thank you for your comment. Changes to text were made by other comments that made the identified section more clear.

AZPS	General Comment		AZPS agrees with EEI's comment that the purpose of MOD-031 is 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" while MOD-032's purpose is to "establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system." The guidance contained in this Reliability Guideline seems to change the intended purpose of MOD-031, which is to aggregate load forecasts for resource planning, not transmission planning.	This mixing of guidance from MOD-032 with MOD-031 is confusing and needs to be more clearly described to better explain why this is appropriate and consistent with the intended purposes of each Reliability Standard. While there needs to be a mechanism that obligates DER owners to supply needed DER specific information/data for planning purposes, this is not the proper platform to achieve that purpose.	Thank you for your comment. Please see response to EEI's comment.
AZPS	General Comment		There are many terms that have not been defined within the document. While most of these terms have been previously defined within other NERC SPIDERWG documents, they remain outside of the NERC Glossary of Terms.	AZPS agrees with EEI's suggestion to include the SPIDERWG Terms and Definitions Working Document (see https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf) along with any other terms used within this guideline that are not included in that document.	Thank you for your comment. Please see response to similar EEI comment.
AZPS	Page vi	Line 115 - 116	The inclusion of Integrated Resource Plans (IRPs) within this guideline could cause some confusion for entities that are not required by their state to develop such a plan.	AZPS agrees with EEI's comment that the information in the guideline regarding IRPs may be useful guidance for affected entities, the guideline should be broad enough to consider alternatives for those who do not have similar regulatory obligations	Thank you for your comment. Please see response to EEI's comment.
AZPS	Page vii	Lines 151 – 152	AZPS agrees with EEI's suggested edits to align with the responsibilities as defined by NERC's Compliance Registry.	The following language should be added: RPs should coordinate with other RPs in their area to ensure resources are not being double counted	Thank you for your comment. Please see response to EEI's comment.
AZPS	Page vii	Line 153 – 155	AZPS agrees with EEI's suggested edits to the second bullet.	Suggested Language: TPs and PCs should coordinate between their load forecasting and planning departments to ensure forecasts align with their requirements (i.e., the development of base cases) in order to ensure TPs/PCs have a clear understanding of forecast assumptions.	Thank you for your comment. Please see response to EEI's comment.
AZPS	Page vii	Line 156 – 158	AZPS disagrees with the recommendation that TPs and PCs should be improving their relationships with DER developers and owners. Developing or improving relationships is subjective and unmeasurable. In addition, the responsibility for gathering needed resource information is the responsibility of the RP (noting that the RP may in some cases also be the TP or PC).	AZPS agrees with EEI's suggested edits: RPs should improve their relationship with DPs in order to gather data needed by TPs and PCs to allow for improved DER forecasting.	Thank you for your comment. Please see response to EEI's comment.
AZPS	Page vii	Line 159 – 160	It is unclear what the intent is for the fourth bulleted recommendation. Figure 2.2 does not contain checklists that might inform the industry	AZPS agrees with EEI's request that the reference to Figure 2.2 be corrected or that the guideline be revised to provide the intended checklist	Thank you for your comment. Please see response to EEI's comment.
AZPS	Page vii	Line 161 – 163	The fifth bulleted recommendation is not clear.	AZPS agrees with EEI's request that consideration be given to rewording this recommendation to provide clearer direction to the industry	Thank you for your comment. Please see response to EEI's comment.

AZPS	Page ix	Lines 168 through 177	Not all NERC registered entities operate in states that require IRPs.	AZPS agrees with EEI's suggestion that less focus be placed on state regulatory requirements and instead provide direction which is more generic and more useful to all NERC registered entities. From this perspective, the purpose of Transmission Planners is to assess the long-term reliability of their transmission planning area. As such, TPs need to coordinate with their RPs, GOs, DPs, TOs, TSPs and connected TPs in order to better understand the locational impacts of DERs, including both utility scale and areas where residential DERs might impact distribution loads. Guidance that recognizes that RPs, TOs and DPs are the entities who have the most accurate information on DERs impacts and changes and growth patterns under the responsible TP purviews as well as where areas where DERs are being planned over the TPs planning horizon should be the focus. While IRPs might factor into those insights, their relevance to DER modeling is not relevant to all NERC registered entities and should not be a significant focus.	Thank you for your comment. Please see response to EEI's comment.
AZPS	Page ix	Line 189; Figure I.1	While Figure I-1 shows distinct differences in the forecasting procedure, the document lacks a clear explanation of the processes necessary to understand those differences.	Recommend updating Figure I-1 to provide more clarity.	Thank you for your comment. Please see response to similar EEI comment.
AZPS	Page ix	Lines 196 - 201	The discussion contained in this section where the guideline contrasts protections and forecasts in the context of DERs does not seem to add value.	While this may be a point worth contrasting, additional language clarifying the intended purpose may be useful for those developing DER forecasts for their companies.	Thank you for your comment. Please see response to similar EEI comment.
AZPS	Page 1	Lines 251 - 255	AZPS agrees with EEI's comment that a distinction between DERs that are aggregated under Order 2222 and those that do not meet the definition of BES or are exclusively for local distribution may be beneficial here given the approach to developing effective forecasts would be impacted by how the resources will be used.	Recommend language that distinguishes between DERs that are aggregated under Order 2222 and those that do not meet the definition of BES or are exclusively for local distribution be added.	Thank you for your comment. Please see response to EEI's comment.
AZPS	Page 5	Line 404	While the identification of various DER forecasting methods is beneficial, the guideline would be enhanced with the inclusion of hyperlinks to industry white papers that describe in more detail the identified methods and industry successes through their use. A comparison of the various modeling options listing pros and cons between the various options might also be helpful for entities seeking to improve their modeling methods.	Include hyperlinks to industry white papers that describe in more detail the identified methods and industry successes. Include comparisons of the various modeling options listing pros and cons between the various options. An example of this can be seen in the NREL document titled "an Overview of Distributed Energy Resources (DER) Interconnection: Current Practices and Emerging Solutions." See	Thank you for your comment. Please see response to similar EEI comment.
AZPS	Page 8	Line 456, Footnote 14	The EPRI reference document in this footnote should contain a hyperlink for easy use by the reader. EEI notes that this document has been made publicly available by EPRI	AZPS agrees with EEI's comment that the EPRI reference document in this footnote should contain a hyperlink for easy use by the reader.	Thank you for your comment. Please see response to EEI's comment.
AZPS	Page 8	Line 475 through 483	Examples of entities who are conducting forecasts of DERs would be useful guidance to the industry.	We suggest including links to detailed examples that could help entities to make smarter decisions and to learn from other entities experiences	Thank you for your comment. Added links to entity pages or filed documents.
AZPS	Page 10	Line 527	On line 527 the acronym CEC is used but is not defined until Line 630 (i.e., California Energy Commission).	Acronyms should be defined the first time they are used. EEI suggests defining CEC on line 527 and using CEC on line 630	Thank you for your comment. Please see response to EEI's comment.
AZPS	Page 10	Line 527	References should be included in the guideline.	References such as the presentation titled "Demand Analysis Working Group (DAWG), Additional Achievable Energy Efficiency (AAEE) Process" should be referenced within the guideline in order to provide additional detail and context	Thank you for your comment. Please see response to similar EEI comment.

AZPS	Page 12 & 13	Lines 574 & 603 to 614	The guideline states that the “MOD-031 serves as the primary NERC standard associated with DER forecasting.” However, the SPIDERWG Reliability Standards Review white paper (See https://www.mro.net/MRODocuments/Whitepaper%20SPIDERWG%20Standards%20Review%2003092021.pdf) identifies concerns with MOD-031 implying that the Standard, as currently written, is not sufficient to allow PC to clearly identify “how much actual demand is on the system given the amount being served by embedded generation”. (See page 16 of the white paper.)	AZPS requests that clarification regarding the discrepancies between the two documents be made.	Thank you for your comment. Please see response to similar EEI comment.
AZPS	Page 13	Lines 622 through 623	AZPS suggests modifications to the last sentence in this section for clarity.	AZPS agrees with EEI's proposed language: If using MOD-031 to ask for DER information, a clear description of the item[s] that are needed should be placed in the data request to ensure the desired data is understood and identified as DER specific data.	Thank you for your comment. Please see response to EEI's comment.
AZPS	Page 13	Lines 625 through 632	AZPS suggests modifications to this paragraph.	AZPS agrees with EEI's proposed language: 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. In this circumstance the PC should consider adjusting and validating their system-wide set up to more closely represent the anticipated load in the base case. 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. PCs should also consider using data from trusted outside sources obtained outside of their MOD-031 data request. As an example of this type of supplemental data, Figure 2.2 shows data from the California Energy Commission (CEC) that provides their expected solar PV rooftop forecast for public use. Such data can be used to help refine the base case assumptions used for future case setups.	Thank you for your comment. Please see response to EEI's comment.
AZPS	Page 15	Lines 650 – 651	AZPS does not agree with the statement that “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.” In reviewing the relationships identified in the last approved NERC Functional Model, we find no role for TPs and PCs to gather data from “distribution entities.” Moreover, there are no obligations by distribution entities to provide such data to TPs and PCs.	AZPS suggests that TPs and PCs work with DPs in order to better understand and interpret forecasted values for DERs and load since it is the DP who has the relationships with interconnected DERs.	Thank you for your comment. Please see response to similar EEI comment.
Duke Energy			No comments		Thank you. No comments noted.
The Entergy Operating Companies: Entergy Arkansas, LLC, Entergy Louisiana, LLC, Entergy Mississippi, LLC, Entergy New Orleans, LLC, and Entergy Texas, Inc.	4	74	RSTC is not defined	Spell out RSTC on first use	Change made as proposed
The Entergy Operating Companies: Entergy Arkansas, LLC, Entergy Louisiana, LLC, Entergy Mississippi, LLC, Entergy New Orleans, LLC, and Entergy Texas, Inc.	10	215	Statements regarding historical data seem to assume that utilities now have “robust source data… for gross load” but this is not typically the case. For example, Entergy measures net load at the meters, and do not have visibility behind the customer meter. Any DERs installed behind the meter are netted with the load behind the meter. Determining the gross load requires making assumptions about the activity of the load and DER.	Clarify that the use of real time data is ideal, where it is available.	Changes made in paragraph due to this and other comments. Notably, the language of "robust data source" is omitted from the revision.
The Entergy Operating Companies: Entergy Arkansas, LLC, Entergy Louisiana, LLC, Entergy Mississippi, LLC, Entergy New Orleans, LLC, and Entergy Texas, Inc.	10	283	U-DER is not defined	Spell out U-DER when it is first used	U-DER now added in text of document. Link to SPIDERWG terms and definitions page included in Introduction section.

The Entergy Operating Companies: Entergy Arkansas, LLC, Entergy Louisiana, LLC, Entergy Mississippi, LLC, Entergy New Orleans, LLC, and Entergy Texas, Inc.	12	286	R-DER is not defined	Spell out R-DER when it is first used	Link included to SPIDERWG terms and definitions page included in the Introduction. Spelled out on first use
The Entergy Operating Companies: Entergy Arkansas, LLC, Entergy Louisiana, LLC, Entergy Mississippi, LLC, Entergy New Orleans, LLC, and Entergy Texas, Inc.	12	e.g. Footnote 7	Hyperlinks to reference documents	Include the full web address for hyperlinks to other documents. Security policies at some companies prevent access to hyperlinks in pdf documents; users at those companies will need to copy and paste the URL to access the external document.	Changes made based on comment.
The Entergy Operating Companies: Entergy Arkansas, LLC, Entergy Louisiana, LLC, Entergy Mississippi, LLC, Entergy New Orleans, LLC, and Entergy Texas, Inc.	24	634	Figure 2-2 has a typographical error in the title	Maximum is misspelled in the title of the figure	Change made as proposed to figure title
The Entergy Operating Companies: Entergy Arkansas, LLC, Entergy Louisiana, LLC, Entergy Mississippi, LLC, Entergy New Orleans, LLC, and Entergy Texas, Inc.	25	653	Line 653 states that "The DP is the functional entity that contains a direct relationship with the DER…" This is only true for DER directly connected to the distribution system. Behind-the-meter DER is not directly visible to the DP, and the DP often has little or no knowledge of what is happening behind the meter.	These guidelines should not assume that the DP has access to this information.	Altered text to ensure the definition of DER is clear in the SPIDERWG documents as a "source of power on the distribution system". Further clarity added on the possible lack of information from the DP.
The Entergy Operating Companies: Entergy Arkansas, LLC, Entergy Louisiana, LLC, Entergy Mississippi, LLC, Entergy New Orleans, LLC, and Entergy Texas, Inc.	35	839 and 840	It can not be assumed that a DER developer is a "trustworthy" source of data or that the TP does not have the most reliable data for forecasting DER activity for system planning purposes.	Revise to recommend that TPs and PCs should establish credible and consistent data sources to be used to forecast the impact and behavior of DERs.	Thank you for your comment. Changes made based on this and other comments.
Electric Reliability Council of Texas, Inc. (ERCOT)	vi	126	Simplify the sentence.	and studied.	Change made as proposed
Electric Reliability Council of Texas, Inc. (ERCOT)	vi	126-127	The last two sentences in the paragraph require cleanup for punctuation and extraneous words.	This does not mean, however, that all entities must have an elaborate forecasting procedure. It does mean that entities should be aware of how differing projections in their area can impact their planning decisions.	Change made as proposed
Electric Reliability Council of Texas, Inc. (ERCOT)	vi	139	Typo	while the bottom up approach creates projections	Change made as proposed
Electric Reliability Council of Texas, Inc. (ERCOT)	viii		The introduction seems to be geared toward utilities that perform IRPs. However, we think the recommendations are relevant for entities/regions that do not perform IRPs.	Suggest rewording the intro (and other similar references throughout the document) to make it more inclusive for entities/regions that do not do IRPs.	Added some text to the Introduction for regions that do not perform IRPs.
Electric Reliability Council of Texas, Inc. (ERCOT)	ix	199-201	This sentence is unclear. Particularly, "…but may only propose transmission upgrades to developing their transmission system until such resources became more firm."	Revise sentence to clarify intent.	Clarified statement as indicated in the comment.
Electric Reliability Council of Texas, Inc. (ERCOT)	ix	203-211	This paragraph is verbose. The gist of it is that entities are finding value in using a wider variety of scenarios when combining transmission and distribution planning cases.	Simplify the paragraph.	Edits made throughout the paragraph to simplify.
Electric Reliability Council of Texas, Inc. (ERCOT)	x	Paragraph starting at line 213	It is not clear what this paragraph is trying to communicate, but we offer the following proposed change based on what we think it is saying.	Load forecasts for areas/ circuits with DER should consider both historic and forecasted DER growth for the area/ circuit separate from the gross load forecast. Failing to do so will cause incorrect load forecast growth assumptions and results since DER output is not correlated with load consumption and because DER growth may occur at a different rate than load growth. However, there are challenges in considering historic and forecasted DER growth in load forecasts if DER output is not explicitly metered.	Changes made based on proposed edit.
Electric Reliability Council of Texas, Inc. (ERCOT)	x	227-229	Wording is not clear/ misleading.	In the case of DER, it is important for TPs and PCs to track the capacity, vintage, and location of DER as these assumptions can often have as large of an impact on future scenario study results as load forecasts can.	Changes made based on proposed edit.
Electric Reliability Council of Texas, Inc. (ERCOT)	x	233	Suggested edit.	Additionally, this document describes aims to demonstrate current	Changes made based on proposed edit.
Electric Reliability Council of Texas, Inc. (ERCOT)	1	240	Suggested edit.	…context of resource and transmission planning.	changes made bas proposed
Electric Reliability Council of Texas, Inc. (ERCOT)	1	242	Suggested edit.	generation and load needs under at a variety of future conditions.	changes made based on proposed edit.
Electric Reliability Council of Texas, Inc. (ERCOT)	2	321	Missing word	Resource profiles provide installation specific or aggregate data to indicate how the total DER output changes in time.	Changes made as proposed

Electric Reliability Council of Texas, Inc. (ERCOT)	2	319-320	Awkward sentence construction	This is largely important with solar PV production data that has a strong temporal correlation with an associated simulated resource profile.	Changes made as proposed
Electric Reliability Council of Texas, Inc. (ERCOT)	3	326	Alternate word suggestion	In short, these profiles provide a way to convert capacity based projections into	Changes made as proposed
Electric Reliability Council of Texas, Inc. (ERCOT)	3	318-327	It would help to use the term "synthetic profile" and indicate that the profile is developed by feeding weather data into a power conversion model. By changing weather assumptions, the profile can reflect alternate production trends, such when extensive cloud cover or a storm occurs during reliability "high risk" hours.		Added text that incorporates the concepts in the comment.
Electric Reliability Council of Texas, Inc. (ERCOT)	6	409	Suggested edit; capitalize Bass	Bass diffusion	Changes made as proposed
Electric Reliability Council of Texas, Inc. (ERCOT)	8	462	Typo	Delete the comma: As purchase, decisions vary	Changes made as proposed
Electric Reliability Council of Texas, Inc. (ERCOT)	13	619-621	Sentence is verbose.	When creating a base case, certain assumptions are made based on the composition of the multiple elements and resources in order to produce a starting position.	Changes made based on proposed edit.
Electric Reliability Council of Texas, Inc. (ERCOT)	13	625-627	Sentence is verbose and confusing.	As a hypothetical example, if DER is not explicitly requested, a PC might find that, in aggregate, their data request under MOD-031 resulted in a load value higher than the base case value used for the next year. The PC then must adjust the load values to account for the missing DER impact.	Changes made based on proposed edit.
Electric Reliability Council of Texas, Inc. (ERCOT)	14	634	Typo in chart title.	Change to "Maximum"	Change made as proposed.
Electric Reliability Council of Texas, Inc. (ERCOT)	14	638-640	Overhaul the text.	This section highlights best practices for disaggregating DER into appropriate values for building future-year base cases.	Change made as proposed
Electric Reliability Council of Texas, Inc. (ERCOT)	15	650-653	The sentence is verbose and should be shortened.	One useful strategy for improving base case forecast assumptions is to build up the relationships with distribution entities in order to more easily get useful ancillary information for validating and interpreting the forecast values.	Change made as proposed
Electric Reliability Council of Texas, Inc. (ERCOT)	17	700-702	It is not clear what is meant by "larger DER projections" in the following sentence: "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.	Replace "larger DER projections" with "broader geographic scope" if that is the intended meaning.	Clarity edits made to the entire paragraph based on the comment.
Electric Reliability Council of Texas, Inc. (ERCOT)	18	713	Wording change	however, an additional set of points, in Table 2.1, should be kept in mind when creating base cases.	Changes made as proposed
Electric Reliability Council of Texas, Inc. (ERCOT)	18	Table 2.1	Missing word under Key Points for DER Location (Load Bus)	Change "gain" to "to gain".	Change made as proposed
Electric Reliability Council of Texas, Inc. (ERCOT)	20	732	Suggested edit.	differing projections impact the end forecast	Change made as proposed
Electric Reliability Council of Texas, Inc. (ERCOT)	20	753	Missing word	Replace "opposed" with "as opposed."	Change made as proposed
Electric Reliability Council of Texas, Inc. (ERCOT)	22	782-784	Clean up the sentence.	ISO-NE provided an example that highlights the approaches and recommendations from the previous chapters. ISO-NE's load forecast department uses a top-down forecasting approach for each state.	Change made as proposed
Daniel Gacek on behalf of Exelon Corporation	General Comment		Exelon supports the development of the DER Forecasting Reliability Guideline. Exelon is a member of the EEI and concurs with the comments submitted by the EEI.		Thank you for your comment and support. Please see the EEI comment responses for particular response to EEI comments.

Georgia Transmission Corporation	General Comment		Overall, it's unclear as to why NERC and SPIDER has not focused on the larger concern with DER, which is quantifying DER penetration levels that would potentially impact the BES. In the past two years, the SPIDERWG has produced five reliability guidelines (3 approved and 2 drafts), five white papers (with a sixth planned for 2022), and one failed SAR, all related to the need to model and study DER. None of which has focused on quantifying DER penetration levels that would potentially impact the BES. Quantifying problematic DER penetration levels would help utilities to determine the appropriate level of DER details to include in their system models. In other words, it appears that the products being proposed by SPIDER need to be prioritized better such that industry resources can be more efficiently utilized.		Thank you for your comment. SPIDERWG reiterates that in order to study impact, models of high quality are needed. In order to populate models, accurate data is required. SPIDERWG's modeling and study documents focus on the procurement of accurate data and development of high quality models to be used in detailed studies for DER impact.
Georgia Transmission Corporation	5	86-102	The RG states that, "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." It is generally understood by industry that failure to review and implement RG recommendations increases the likelihood of the creation of additional NERC standards and/or requirements. As such, RGs should have a meaningful purpose, the effectiveness of which can be measured by distinct and specific metrics. This RG does not include any specific metrics that can be used to measure the effectiveness of the RG at meeting its defined purpose. Furthermore, the usefulness of the recommendations contained is this RG appear to be proportionate with the DER penetration levels on the BES. In other words, these recommendations appear to be unnecessary for lower DER penetration levels. Without having knowledge of DER penetration levels that would potentially impact the reliability of the BES, industry does not know when to apply the detailed recommendations of this RG. Therefore, this RG would be better suited as a whitepaper.	Convert the reliability guideline to a whitepaper. If the reliability guideline is not converted to a whitepaper, then it should include a clearly defined, meaningful purpose along with distinct and measurable metrics that that can be used to measure the effectiveness of the RG at meeting its defined purpose.	Thank you for your comment. Specific Metrics added based on other comments supplied. Altered text in executive summary to make clear the purpose of the guideline.
Georgia Transmission Corporation	5	93-95	Which before and after measures in the NERC State of Reliability Report and Reliability Assessments will be quantified in effort to evaluate the effectiveness of this guideline?		Thank you for your comment. The SOR contains a table of all indicators in Table 3.1 as a summary used for the Baseline Metrics.
Georgia Transmission Corporation	5	97	The Reliability Guideline (RG) states, "Industry assessment of the extent to which a Reliability Guideline is addressing risk as reported via survey."	This "risk" needs to be clearly defined. What risks is the RG intended to address?	Changes made to executive summary to clarify purpose of the reliability guideline.
Georgia Transmission Corporation	5	102	The RG should include distinct and measurable metrics that that can be used to measure the effectiveness of the RG at meeting its defined purpose.	Add a metric to capture the number of man-hours required for the utility to implement the reliability guideline.	Thank you for the proposed metric. SPIDERWG did not agree that the effectiveness of this Reliability Guideline can be measured by man-hours to implement. No change made
Georgia Transmission Corporation	5	102	The RG should include distinct and measurable metrics that that can be used to measure the effectiveness of the RG at meeting its defined purpose.	Add a DER penetration level metric to the guideline similar to MISO's 2021 Renewable Integration Impact Assessment (RIIA).	Thank you for the proposed metric. This Reliability Guideline focuses on validating data for future year planning cases. SPIDERWG does not believe the effectiveness of the guideline is impacted by DER penetration. No change made.
Georgia Transmission Corporation	6	106	The RG states, "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." What is the basis for this statement?		Thank you for your comment. Sentence has been removed.
Georgia Transmission Corporation	6	139	The RG states, "...focus on the behavior of the whole, while the bottom up approach focuses creates projections of individual..."	Delete the word "focuses", such that it reads, "focus on the behavior of the whole, while the bottom up approach creates projections of individual..."	Change made as proposed

Georgia Transmission Corporation	6	Footnote 2	Footnote 2 reads: 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.	Insert "refers" between "typically" and "to", such that Footnote 2 reads: In this document, the term “forecast” typically refers 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.	Change made as proposed
Georgia Transmission Corporation	7	159-160	The statement refers to "checklists as in Figure 2.2". Where is Figure 2.2 that shows the aforementioned checklists?		Figure 2.5 now contains such information. Changed figure reference for clarity
Georgia Transmission Corporation	11	239-240	The RG states "It is crucial that load and DER forecasts provide adequate and reasonable projections for future studies within the context of comprehensive integrated resource planning."	Unless put into the context of relatively large DER penetrations, use of words such as "crucial" and "critical" in regard to the need for adequate and reasonable DER forecasts tends to overstate the importance of the DER forecast.	Changes made based on proposed edit.
Georgia Transmission Corporation	11	266-268	The RG states, "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 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." Is this common for behind the meter resources? It seems to be more of a transmission connected resource issue.		Thank you for your comment. The reliability guideline identifies that "future studies should… be representative of the conditions under study". No changes made.
Georgia Transmission Corporation	12	Footnote 7	The third link is broken.		Changes made based on comment.
Georgia Transmission Corporation	19	Footnote 16	The link is broken.		Changes made based on comment.
Georgia Transmission Corporation	20	526-527	The RG reads, "The CAISO load forecast utilizes the latest Energy Demand Forecast 526 developed by the CEC."	Replace "CEC." with "California Energy Commission (CEC)."	Change made as proposed
Georgia Transmission Corporation	22	583-584	This statement that MOD-031-2 is the latest version of the MOD-031 standard is incorrect. MOD-031-3 is the current enforceable standard; not MOD-031-2.	Refer to the correct version of the MOD-031 standard.	Changes made based on comment.
Georgia Transmission Corporation	23	607-609	The RG states, "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." What is the tangible benefit of adding this burden to the TP?	If this RG includes statements of recommendations from the SPIDERWG Standards Review White Paper, then it should also summarize the costs/benefits of these recommendations.	Thank you for your comment. Section removed based on this and other comments.
Georgia Transmission Corporation	23	621-622	The RG states, "These assumptions are validated by 621 the forecasted values with the data under MOD-031"	Add a period after "MOD-031".	Change made as proposed
Georgia Transmission Corporation	35	841	The link for "Figure 2.2" does not work.		Should be Figure 2.5, updated link.
PJM Interconnection	vii	159	Should be Figure 2.5 not Figure 2.2		Change made as proposed
PJM Interconnection	viii	180	Either Figure I 1 or the figure title at 190 needs to change to Figure I.1		Change made to figure title identifier based on comment.
PJM Interconnection	1	274-279	Glosses over how to model aggregations from various prior Standards.		Added a link to guidance for subject in comment. Further, the reliability guideline also links the previously approved SPIDERWG modeling guidance in a nearby section from that which the commenter identified.
PJM Interconnection	2	307	First sentence reads awkward.	Suggest: There exists uncertainty with any future long-term projection.	Change made as proposed
PJM Interconnection	5	405	bottoms up should be bottom up		Change made based on comment.
PJM Interconnection	6	408	Eliminate one of the two periods..		Change made based on comment.
PJM Interconnection	6	433	sourced should be sources		Change made based on comment.
PJM Interconnection	6	440	allocate of forecasted		Clarity edit made based on comment
PJM Interconnection	8	479	IS involve supposed to be evolve?		Yes. Change made.
PJM Interconnection	10	527	CEC is used but not defined until p. 13		Change made based on this and other comments.

PJM Interconnection	12	572	NERC has also pushed for PCs to obtain this information via MOD-032. It would be good for a discussion of fidelity between the two.		Thank you for your comment. The comparison of MOD-032 for Interconnection-wide Base Case Creation procedures against MOD-031 requests are located in the Reliability Guideline "MOD-031 and Interconnection-wide Base Case Creation" and in that sections footnotes.
PJM Interconnection	14	634	Chart title misspells Maximum as Maximum		Change made based on this and other comments.
PJM Interconnection	22	772	should it be figure 3.1		Change made based on comment.
PJM Interconnection	22	785	Should it be table 1.1		Change made based on comment.
PJM Interconnection	23	789	Should it be table 1.1		Change made based on comment.
PJM Interconnection	25	841	Should be Figure 2.5 not Figure 2.2		Change made based on comment.
ReliabilityFirst	Overall		The entire paper seems to be focused on the forecast and modeling of peak load conditions. It would be helpful to also include techniques for forecasting off-peak loads (summer shoulder, light load, minimum load, as well as any change in DER as a function of the time of day should also be addressed, or at least mentioned.)		Thank you for your comment. A footnote was added in the "DER Forecasting Methods" section to speak to using the methods for off-peak or on-peak conditions.
ReliabilityFirst	Overall		While note in the direct scope of this document, there are more characteristics of load that would be useful to transmission planners not mentioned here. Some of these are: 1) Any loads that could impact delivery of natural gas to generating plant. 2) The mix of residential, commercial, and industrial loads served by the substation (improved dynamic modeling.) 3) The ability or inability of loads to be moved from one substation to another with speed of transfer being a factor. 4) The power factor of the load during various load periods.		Thank you for your comment. SPIDERWG agrees that the factors are out of scope for this guidance. Added a footnote in the "Level of Load" section to address comment's contents.
ReliabilityFirst	v	102	It would be beneficial to come up with a metric that is more tangible to actually show there is or is not a benefit to modeling DER. Proposed change may fall under "Specific Metrics" section at line 102 There is an existing uncertainty associated with load forecasting in general. Note that it might be worth trying to quantify the % error in existing load forecasting techniques, versus the expected % error when incorporating DER as recommended.	Below are just examples and could be repeated for top-down or bottom-up approaches described in this paper. Based on a representative sample, thermal loading results impacted by XX% based on inclusion of DER data. Based on a representative sample, reported voltage post-contingency changed XX% based on inclusion of DER data. Based on inclusion of DER data XX additional thermal violations were reported, compared to XX baseline thermal violations using case that did not include DER.	Thank you for your comment. Metrics added based on the comment and proposed change.
ReliabilityFirst	vi	149	Correct the verbiage in this sentence.	Change "approach focuses creates projections of" to "focuses on projections of"	Change made based on this and other comments.
ReliabilityFirst	vi	140	This sentence discusses local behavior, behavior as a whole, and individual component behavior. Something needs to be added to make it clear that it is the behavior of load and DER at a specific time that is being discussed.	Change "level desired" to "load level desired"	Change made as proposed.
RF	vi	145	Change the verbiage to be less definitive.	Change "will provide" to "may provide"	Edits made based on comment.
RF	x	213	Change the verbiage to identify the parties performing the load forecasting function.	Change to "If the TP or PC assume any load forecasts provided by the DP do not have…."	Paragraph has been altered due to other comments, this comment, and the proposed edit.
ReliabilityFirst	x	228	Change the verbiage to focus on what should be performed versus what may not be performed.	Remove "In the case of DER, many TPs and PCs may not be aware that" and leave the remainder of the sentence unchanged.	Agreed. Other comment provided a separate way to resolve and was chosen over the removal of language.
ReliabilityFirst	2	footnote	The third "here" is to a broken link.	Reminder to check the links to other documents.	Changes made based on comment.

ReliabilityFirst	5	404	Recommended to add verbiage that indicates the selection of specific DER Forecasting Methods requires careful consideration of the goal, timing, and desired confidence level in the type of analysis that is being performed. For example, it may not be prudent to select a 'Policy-Based Approach' when the data is available for the 'Macroeconomic Simulation' and the confidence level may be higher for the latter method.		Thank you for your comment. Text added based on comment in the section identified.
ReliabilityFirst	12	590	Change the term load flow	Change "load flow" to "power flow"	Change made as proposed
ReliabilityFirst	12	592	This might be for another guideline or forum of discussion but the elimination of the LSE as a NERC designation ultimately has a negative impact on the PC/BA to be able to obtain this type of information from distribution companies. RF has gathered general numbers for each state in the RF footprint related to DP registration. For example, in Ohio there are 110 different LSEs yet only 10 are registered as DPs. RF has actually observed a trend in deactivations of the DP function, with 10 Entities in Ohio deactivating for the DP function since 2017 (approximately half based on count, not based on size).		Thank you for your comment and bringing this problem to our attention. NERC sees value in the comment's content and agrees this is not the forum to discuss the content of this comment but hopes to have a future forum to discuss industry's concerns.
ReliabilityFirst	20	758	Since this information will be passed from the DP/TO to the PC/TP, it may be difficult for the PC/TP to know these details without establishing guidance on labeling the inputs received from the DP/TO on DER characteristics. It is recommended that the PC/TP request labeling associated with the T-D interface to better identify dispatch changes associated with each location.		Text added based on comment.
ReliabilityFirst	25	847	This is essentially a repeat of row 838-840	Remove rows 847-849	Clarified intent of section as the focus of the bulleted recommendation is for TPs and PCs and the second is for other entities such as the Resource Planner.
Southern Company Services		Overall Comment	This document seems better suited to a whitepaper than a Reliability Guideline		Thank you for your comment. This and another comment recommended to change this document to a white paper. SPIDERWG believes this is best suited as a Reliability Guideline.
Southern Company Services	v1	Executive Summary	Applicable in areas with higher penetration levels	Add "in areas with higher penetration levels"	SPIDERWG did not find a place where it was appropriate to add in this statement. No changes made.
Southern Company Services	Vii	151-161	See comments below from bulleted recommendations at end of document. Forecasts should not come from TP/PC. Strike "trustworthy" from outside entity reference.	strike "trustworthy" (157); TP/PC do analysis and should not be responsible for forecasting DER	Thank you for your comment. Text altered based on comment.
Southern Company Services	ix	203	Not necessarily true across the board.	Add "In some regions" to beginning of sentence.	Added text based on proposed edit. Other comments also changed paragraph.
Southern Company Services	13	603-614	Last part of section says this guideline doesn't depend on the outcome of recommended revisions to MOD-031-2	Remove this section	Thank you for your comment. Section removed based on this and other comments.
Southern Company Services	18	713-718	Soften language	Change title of Table 2.1 to "Key Values to Consider…"	Changes made as proposed.
Southern Company Services	24	817	Overgeneralizing recommendations based on informal poll		Thank you for your comment. Adjustments have been made to the language and detailed information is now found in footnotes.
Southern Company Services	25	839	who determines whether an outside entity is "trustworthy"	strike "trustworthy"	Sentence altered based on this and other comments.
Southern Company Services	25	843	Not a TP & PC responsibility	This forecast information should come from somewhere else. TPs do analysis, not forecasting.	Thank you for your comment. Text has been altered to clarify recommendation.
Southern Company Services	1	247	"entities need a trustworthy information…". Need to remove the "a"	"entities need trustworthy information"	Change made based on proposed change
Southern Company Services	6	408	sentence has two periods at the end		Change made based on comment.

Southern Company Services	6	440	Remove "of" in the sentence	"...techniques may be needed to allocate forecasted values"	Change made as proposed
Southern Company Services	8	456	Need to add a "the" in the sentence	"As each of the DER installations represents..."	Change made based on comment and proposed change.
Southern Company Services	10	527	CEC not defined until later in the document		Change made based on comment.
Southwest Power Pool-SPP	12	294-305	The Southwest Power Pool, Inc. supports the guideline in its overall effort to include the effect of DER into the forecasting process via MOD-031. However, SPP recommends that the SPIDERWG consider adding language to the SAR that supports the efforts of the MOD-032 Standard and the importance of data collection, specifically, the components that make up the dynamic information when performing stability assessments. Modeling data of resources (power flow and dynamics information) is supplied to the Planning Coordinators (PCs) through MOD-032 data submissions by the Transmission Planners (TPs), not via MOD-031. SPP, as a PC is concerned that the MOD-032 standard is not applicable to the Distribution Provider DP. The older versions of the MOD-032 standard referenced the LSE (Load Serving Entity), but that designation has been removed from the NERC Entities. This leaves the PCs and TPs in a quandary on how to get the data from the appropriate NERC Entity, which would now be the DP. The only data that PCs and TPs could have access to in the future based on the standards at present would be a vertically integrated TP/DP situation based on NERC registration. Any non-affiliated DPs with the host TPs, currently do not have a NERC responsibility.		Met with comment submitter and clarified intent of comment. Desired addition of a section in the lines identified that discusses the need for data gathering as an input into the forecast. Clarified section related to Interconnection-wide base cases to align with section. Commenter was part of drafting on addition and edits.

White Paper: BPS Reliability Perspectives for Distributed Energy Resource Aggregators

Action
Request for RSTC reviewers.

Summary
The White Paper: BPS Reliability Perspectives for Distributed Energy Resource Aggregators provides bulk power system reliability perspectives and considerations regarding distributed energy resource (DER) aggregation in light of Federal Energy Regulatory Commission (FERC) Order No. 2222, which introduces the concept of DER aggregation in wholesale electricity markets. The SPIDERWG is seeking RSTC members to review and provide comment on the white paper.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

BPS Reliability Perspectives for Distributed Energy Resource Aggregators

NERC System Planning Impacts from DERs Working Group (SPIDERWG)
White Paper
March 2022

Purpose

This white paper provides bulk power system (BPS) reliability perspectives and considerations regarding distributed energy resource (DER) aggregation in light of Federal Energy Regulatory Commission (FERC) Order No. 2222.,[1] which introduces the concept of DER aggregation in wholesale electricity markets. Subsequently, Order No. 2222-A and Order No. 2222-B have been issued.[2] Tariff compliance filings were due July 19, 2021, and some entities have requested extensions for filing or implementation.

While NERC and its technical stakeholder groups are not directly involved in market-related activities, the NERC SPIDERWG recognizes that the introduction of the DER aggregator to the overall electricity ecosystem will have an impact on BPS planning, operations, design, and overall grid reliability. The introduction of the DER aggregator specifically raise questions on how to plan for, model, and simulate the behavior of the DERs contained in the aggregation operated by the DER aggregator. As Transmission Planners (TPs) study the ability to serve load in their area, they will need to account for, as an example, the periodicity of any reduction of power from DER or other Load Modifiers like Demand Response of the DER aggregators and the capability from these resources to serve large motor loads (e.g., arc furnace loads, heavy industry loads, harmonic generating loads, etc.) in the simulations performed by the TP. This white paper is intended to provide BPS reliability perspectives on various requirements within FERC Order No. 2222. It also discusses ways that Regional Transmission Organizations (RTOs)/Independent System Operators (ISOs), which are generally registered as BAs and RCs, can leverage existing SPIDERWG guidelines and recommended practices when developing tariff revisions or business practices responsive to FERC Order No. 2222.[3] The paper also provides recommendations for areas of future work that SPIDERWG or another NERC technical stakeholder group should pursue to better address any gaps. This white paper explores the following high-level concepts that RTOs/ISOs should consider in their implementation of FERC Order No. 2222:

- How the implementation of FERC Order No. 2222 could impact the ability of Transmission Planners (TPs) to ensure BPS planning and operating models and simulations are remain accurate as DERs continue to proliferate and participate in DER aggregation

[1] FERC Order No. 2222, *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators,* issued September 17, 2020, effective December 21, 2020.
[2] FERC Order No. 2222-A was issued March 18, 2021 and effective June 1, 2021. FERC Order No. 2222-B was issued June 17, 2021 and effective August 27, 2021.
[3] All ISO/RTOs are registered with NERC as Balancing Authorities (BAs), Planning Coordinators (PCs), and Reliability Coordinators (RCs) and have an important role and responsibility for ensuring BPS reliability in the planning and operations time horizons.

    - Which entities are responsible for providing the data[4], what data is being requested, and which entities receive the data[5]

- How to ensure that the study cases used by TPs and PCs appropriately reflect the expected operating conditions of DERs and the results of implementing FERC Order No. 2222

    - What data is needed at various stages of these studies, and how the data is maintained at the distribution and transmission level

- How the implementation of FERC Order No. 2222 ensures that Transmission Operators (TOPs) have sufficient visualization of aggregate DERs to operate within System Operating Limits (SOLs)

Background

The NERC SPIDERWG was established in December 2018[6] as a stakeholder forum to focus on the impacts and benefits that aggregate amounts of DERs may have on transmission planning and BPS reliability. SPIDERWG develop guidelines and recommended practices in the following areas: modeling, verification, studies, and coordination.[7]

With the continued integration of large amounts of DERs in many areas across North America and the projections of future DER growth in the future, combined with the introduction of DER aggregation and the participation of DER aggregators in wholesale electricity markets, SPIDERWG believes it is necessary to shed some light on some key reliability-focused aspects of the new paradigm of grid planning, operations, design, and engineering. The FERC Order No. 2222 addresses the ISO/RTOs directly, and most of those companies are registered as a BA, RC, TOP, PC or a combination of the four. As such, the recommendations this paper has may be directed at ISO/RTOs and to BAs, RCs, TOPs, and PCs, and will sometimes address the same entity. This SPIDERWG whitepaper follows some of the key considerations of FERC Order No. 2222 and existing requirements DER interconnection (e.g., IEEE 1547-2018), and provides perspectives for helping ensure continued reliability, security, and resilience of the BPS.

Terminology

In FERC Order No. 2222, FERC amended the OATT by defining both “DER” and “DER aggregator” as shown here:

> **Distributed Energy Resource (DER)**:[8] any resource located on the distribution system, any subsystem thereof or behind a customer meter.

[4] MOD-032 currently has the TP and PC engage with the TO in order to obtain DP level data aggregated to an appropriate BPS bus. It is assumed for this question that the DER Aggregator would engage with the DP in this same manner.
[5] Unclear procedures can impact the ability of the TP to gather appropriate data for their simulations. Specifying the data, who provides the data, and who receives the data makes a clear process for the DER aggregators to interface with.
[6] https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Scope.pdf
[7] https://www.nerc.com/comm/RSTC/Pages/SPIDERWG.aspx
[8] FERC Order No. 2222, page 93, P114

Distributed Energy Resource Aggregator (DER aggregator):[9] the entity that aggregates one or more distributed energy resources for purposes of participation in the capacity, energy and/or ancillary service markets of the regional transmission organizations and/or independent system operators.

FERC clarified that for the purposes of the OATT, DER may include but are not limited to "resources that are in front of and behind the customer meter, electric storage resources, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment" as long as such resource is "located on the distribution system, any subsystem thereof or behind a customer meter."[10] FERC Order No. 2222 neither amended nor proposed to amend the Glossary of Terms Used in NERC Reliability Standards nor the NERC Rules of Procedure.

SPIDERWG maintains a set of working definitions related to DERs, which informs reliability guidelines and recommended practices produced by SPIDERWG. SPIDERWG has defined "DER" to strictly refer to *sources* of electric power on the distribution system[11] (not inclusive of load resources). On the other hand, the definition presented in FERC Order No. 2222, defines DER as *any resource* located on the distribution system. The distinct difference between definitions is that the FERC definition is inclusive of demand response[12] and load elements whereas the SPIDERWG working definition excludes demand response as it is not considered a source of power (it is considered a Load Modifier). The SPIDERWG aligns with the definition of DER presented in IEEE 1547-2018,[13] and is considered appropriate for the purposes of reliability-centric discussions. Unless otherwise noted, this whitepaper uses terms defined in the SPIDERWG Terms and Definitions Working Document.[14] It is understood that the definition used in FERC Order No. 2222 are related specifically to electricity markets and that different definitions for DER-related activities can be used for the purposes of reliability-centric discussions around DER integration and aggregation.

Key Recommendation

The SPIDERWG terms for DER is considered appropriate for reliability-focused discussions and is used throughout this document unless otherwise noted. Regardless of any differences in the definition of DER, it is imperative that industry ensure a clear and appropriate definition of DER based on the specific context in which the term is being used for either reliability or market-related discussions.

Quick Overview of FERC Order No. 2222

This section provides a brief overview of the specific requirements and facets in FERC Order No. 2222 that the SPIDERWG believes are particularly important to understand their impact to ensure BPS reliability. Specifically, these focus areas include, at a minimum, the following:

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[9] FERC Order No. 2222, page 95, P118

[10] FERC Order No. 2222, page 93, P114

[11] These resources can also inject power to the BPS through the distribution system. This concept is covered in the various modeling Reliability Guidelines provided in the Modeling section of this white paper.

[12] FERC Order No. 2222, Paragraph 114, Page 93 of 290

[13] https://standards.ieee.org/standard/1547-2018.html

[14] https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf

- DER aggregations participating in RTO/ISO-organized wholesale electric markets
- Establishing DER aggregators as a type of market participant
- DER aggregators registering DER aggregations under one or more participation models that accommodate the physical and operational characteristics of the DER aggregations
- Establishing market rules that address the following technical considerations:
  - Minimum size requirement for DER aggregations that does not exceed 100 kW
  - Locational requirements for DER aggregations
  - Distribution factors and bidding parameters for DER aggregations
  - Information and data requirements for DER aggregations
  - Metering and telemetry requirements for DER aggregations
  - Coordination between the RTO/ISO, the DER aggregator, the distribution utility, and the relevant electric retail regulatory authorities
  - Modifications to the list of resources in a DER aggregation
  - Market participation agreements for DER aggregators
- Bidding from DER aggregators where the DERs are customers of utilities that distributed more or less than 4 million MWh of energy in the previous fiscal year

These topics will be covered in the following sections, particularly in how they are being addressed by the NERC SPIDERWG and its focus on modeling, verification, studies, and coordination.

Key BPS Reliability Areas with the Introduction of DER Aggregators

The introduction of the DER aggregator will have an effect on BPS reliability, particularly in the way that BPS operations and planning will have to adapt to the DER aggregator. However, it is first important to understand that those impacts will differ from impacts that increasing interconnection of new DERs will simultaneously have on BPS reliability. Further, the interconnection of new facilities[15] also encompasses modifications made to existing interconnections as changes to existing DER facilities requires similar studies and coordination efforts as if the facility was adding a new generator. The key reliability areas that should be considered with the introduction of a DER aggregator in a TP/ PC area that include at least the following:

- **Interconnection Standards:** These standards dictate the equipment requirements, specifications, and capabilities of the DER facility. Many of these standards deal the electrical characteristics and equipment properties to help control things like harmonics in the inverter. IEEE 1547-2018 is a prominent standard related to DER that defines how manufacturers produce their equipment.

[15] This interconnection can occur under an aggregation operated by a DER aggregator or outside of an aggregation operated by a DER aggregator.

SPIDERWG developed guidance[16] on IEEE 1547-2018. Such guidance sufficiently will cover the DER aggregator[17], thus no revision of the standards with the introduction of a DER aggregator is required at this time.

- **Services Provided:** The NERC Essential Reliability Services Task Force (ERSTF) enumerated a few services that a resource can offer to maintain the reliability of the BPS[18]. The RTO and ISO may have markets available to procure enough resources in support of those services. The Distributed Energy Resource Aggregator may be able to alter the type and quantity of a specific service for a specific aggregation of DER.
- **Electrical Characteristics at T-D Interface:** The Transmission to Distribution Interface (T-D Interface) is the point at which the distribution system meets the transmission system, primarily modeled with a load at a BPS bus in the positive sequence transmission models. The electrical characteristics at this interface are dictated by the equipment sinks or sources on either side of the Interface, inclusive of DER, and the operation of such equipment. Inverter settings and control logic from the DER equipment are one impact the T-D Interface. Such settings are gains and values that dictate the inverter behavior based on various electrical quantities. The DER aggregator may be able to alter a few, none, or all of a specific inverter's settings, which impacts how the DER facility[19] performs and resulting in changes in electrical characteristics of the T-D Interface. As the electrical characteristics of the T-D Interface change, the impact on the bulk system planning and operations will alter to accommodate new modes of operation brought on. DER aggregators may impact the procedures of BPS planning and operations through changes in the studies of the planning/operations area and the impact to the protection, automation, control, and communication systems. This may result in changes[20] for the interconnection (i.e. new or changed capacity or capabilities) and aggregation (i.e. grouping of facilities) process.

Key Takeaway

The introduction of a DER aggregator does not significantly alter interconnection of DER. Rather, the DER aggregator impacts the broader electrical characteristics at the T-D Interface.

In general, the introduction of the DER aggregator in a TP or PC's area does not significantly alter the current interconnection procedures for DERs nor does it significantly alter the need to account DERs in planning assessments. However, the possible alteration of DER equipment (inverter) settings, services that DERs can provide, and the electrical characteristics of the aggregator controlling DERs could create new impacts to the distribution system and BPS. These possible impacts inform the way a TP reviews an aggregation or performs coordination with their protection, automation, and control to ensure reliability of the bulk

[16] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Guideline_IEEE_1547-2018_BPS_Perspectives.pdf

[17] Depending on if the DER aggregator is able to control and operate equipment outside of the "distribution" system (i.e., not under IEEE 1547-2018) then other standards may be applicable such as IEEE p2800.

[18] The 2015 ERSTF report can be found here: https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf

[19] Inverter settings have been identified as a reason bulk facilities have tripped due to disturbances. As solar PV is the largest type of DER today, it reasonably follows that a key reliability aspect of DER is also the inverter settings.

[20] This can include items like physical "metal-in-the-ground" changes to the system. All of these changes are a result of larger BPS Planning and Operations paradigm changes.

system. Establishing control of existing DER under a DER aggregator will likely undergo a different, milder level of study by the TP than interconnection of new DER capacity. Modeling, verification, and studies including the DER aggregator as well as tight coordination between transmission and distribution entities will be critical for maintaining a reliable, resilient, and secure BPS moving forward. The following sections will outline the important modeling, verification, studies, and coordination considerations regarding the incorporation of the DER aggregator.

Modeling

Figure M.1 shows the paragraphs from FERC Order No. 2222 that are particularly relevant for the purposes of modeling aggregate DERs in reliability studies with the introduction of the DER aggregator.

Paragraph 142. *"We… require each RTO/ISO to revise its tariff to allow different types of distributed energy resource technologies to participate in a single distributed energy resource aggregation (i.e., allow heterogeneous distributed energy resource aggregations)."*

Paragraph 236. *"…we require each RTO/ISO to revise its tariff to (1) include any requirements for distributed energy resource aggregators that establish the information and data that a distributed energy resource aggregator must provide about the physical and operational characteristics of its aggregation; (2) require distributed energy resource aggregators to provide a list of the individual resources in its aggregation; and (3) establish any necessary information that must be submitted for the individual distributed energy resources."*

Paragraph 237. *"…we require the RTOs/ISOs to revise their tariffs to establish any necessary physical parameters that distributed energy resource aggregators must submit as part of their registration process only to the extent these parameters are not already represented in general registration requirements or bidding parameters applicable to distributed energy resource aggregations."*

Figure M.1 Relevant Modeling Paragraphs

For BPS reliability studies, consistent with SPIDERWG recommended practices, DERs should be modeled in aggregate at the BPS bus. The introduction of the DER aggregator is likely to have an impact on DER modeling practices in the future, particularly in how TPs and PCs will model[21] or represent how aggregate levels of DERs perform when under control of a DER aggregator yet does not impact the major recommended modeling practices of SPIDERWG at this time. SPIDERWG's guidance on representing DER in aggregate at the BPS bus in an explicit way is not altered from the introduction of a DER aggregator. Conversely, the parameterization and adaption of the model framework to suit the operational characteristics of an aggregation may alter.

Key Recommendation
Aggregating DER in the context of the OATT will not have a significant impact on recommended SPIDERWG modeling practices.

Representing all of the heterogeneous components of a DER aggregation may require, for instance, including the behavior of aggregate inverter-based residential DER (modeled as Retail-Scale Distributed Energy Resources, or for short R-DER[22]) in one component of a load model, and representing the charging behavior of electric vehicles in another component of a load model (electronic load). This can be seen in Figure M.2 that details where these components are represented in the DER modeling framework.

[21] Further, as equipment under DER aggregators can include components of Load, the information provided by a DER aggregator may be useful in the development of the composite load model. The SPIDERWG recommendation to model DERs in aggregate at the BPS bus (i.e. through a T-D Interface) is consistent with the evolution of the composite load model performed by other industry groups.

[22] Details on the model distinctions between R-DER and U-DER available in the following three NERC Reliability Guidelines: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_-_Modeling_DER_in_Dynamic_Load_Models_-_FINAL.pdf, https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_A_Parameterization.pdf, and https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_Data_Collection_for_Modeling.pdf

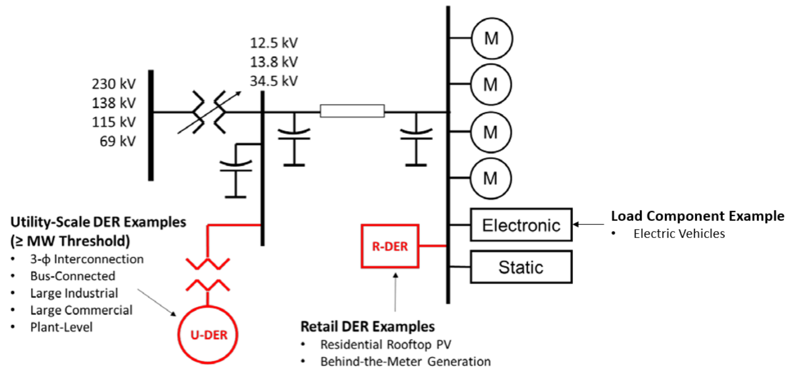

Figure M.2 DER Modeling Framework with DER Components and Load Components

Consideration should be given to providing model information to the responsible DPs, TPs, and PCs for inclusion in their studies. The method for information flow between and among a DER aggregator, DP, TP, and PC will vary based on the market structure. At a minimum, interconnection agreements should use the information provided in Appendix B of the *Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies*[23] as a baseline for the specific modeling information[24] provided. For more information on these physical parameters, RTOs/ISOs should see the discussion on the Steady-State (Chapter 2), Dynamics (Chapter 3), and Short Circuit (Chapter 4) data requirements in the document. As DER interconnect into the distribution system[25], their aggregate response needs to be clearly understood by the DPs, TPs, and PCs who study its response.

In other words, DER aggregators along with its respective DP(s) should be identified as key source of data for BPS planning studies (steady state, dynamics, short circuit). Furthermore, RTOs/ISOs should take care to ensure that any defined locational requirement for DER aggregators be appropriately reflected in the dispatch and parameterization of DER in the various base cases. As the DER aggregator and DP geographic areas can be different, there is a need for the DP to obtain data for the interconnection by interfacing with DER aggregators in their area. Thus, the DP is the logical choice to be involved with the DER aggregators and to provide data to the TP or TOP where appropriate.

Based on SPIDERWG discussion, the modeling, verification, and study of DER in aggregate will need high quality data flowing to the TP and PC who perform those functions. The DER aggregator is identified as a key entity who can provide information and should be sending detailed information for study to the DP, and the DP sending aggregate information to its respective TP and PC.

[23] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_Data_Collection_for_Modeling.pdf
[24] In particular, the composition and control logic of the aggregation under a DER aggregator is important to send to the responsible DPs, TPs, and PCs to include in their models in order to accurately perform their studies.
[25] Sometimes the injection is through the distribution system into the bulk system, resulting in bulk system injection.

Verification

Figure V.1 shows the paragraphs from FERC Order No. 2222 that are particularly relevant for the purposes of verification activities with the introduction of the DER aggregator.

> **Paragraph 267.** *"…we provide flexibility to RTOs/ISOs to propose specific metering requirements, including any that may apply to individual distributed energy resources that the RTO/ISO demonstrates are needed to obtain any required performance data for auditing purposes and to address double compensation concerns. Similarly, we provide flexibility to the RTO/ISO as to whether to propose specific telemetry requirements for individual distributed energy resources in an aggregation. The need for such requirements may depend, for example, on whether the RTO/ISO allows multi-node aggregations or how multi-node aggregations are implemented. By providing flexibility while also requiring that the RTO/ISO explain why any proposed metering and telemetry requirements are necessary, we allow the RTO/ISO to obtain the metering and telemetry information it needs without burdening the distributed energy resource aggregator to provide data that may not be necessary."*
>
> **Paragraph 268.** *"…we expect that RTOs/ISOs will base any proposed metering and telemetry hardware and software requirements for distributed energy resource aggregations on the information needed by the RTO/ISO while avoiding unnecessary requirements that may act as a barrier to individual distributed energy resources joining distributed energy resource aggregations or to distributed energy resource aggregations participating in the wholesale markets."*
>
> **Paragraph 269.** *"…we note that any additional RTO/ISO metering and telemetry requirements would not change those required by state or local regulatory authorities and would be required solely to assist with settlements and audits of activity in RTO/ISO markets, or to provide RTOs/ISOs with the real-time information needed to reliably and efficiently dispatch their systems."*

Figure V.1: Relevant Verification Paragraphs

When developing telemetry requirements, SPIDERWG recommends that RTOs/ISOs consider using the *Reliability Guideline: Model Verification of Aggregate DER Models used in Planning Studies*[26] as well as established interconnection requirements to determine the technical specifications of electrical metering and the electrical locations for the equipment. It is also important to recognize that new Tariffs allowing participation of DER in aggregate will present unique challenges not seen with more traditional resources[27], so consideration of TP and TOP needs when establishing metering and telemetry requirements to monitor and verify the aggregate DER need to be clear for participating DER. For use by the TP and TOP, metering equipment should support the ability to capture waveforms[28] for playback in order to verify the performance of the DER aggregation in disturbance-based model verification or through event analysis. While individual DER data is not as important to transmit, providing data from where the individual resource aggregates to the transmission system will aid Transmission Planners in developing and studying how the DER aggregator may alter the electrical characteristics of the T-D interface, and verifying the TP and PC's representation of those changes in their set of models. Further, in event analysis it is important to determine root causes and electrical responses of equipment that can affect the Bulk Power System.

[26] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline%20_DER_Model_Verification_of_Aggregate_DER_Models_used_in_Planning_Studies.pdf

[27] Primarily the monitoring of a single Point of Interconnection does not provide the one to one mapping used to verify resource models using disturbance based playback.

[28] For specifics, see Chapter 1 of the *Reliability Guideline: Model Verification of Aggregate DER Models used in Planning Studies* that discusses the placement of devices and data collection for model verification. In general, the focus for waveform capture is at the T-D Interface.

Transmission Planners should take care to evaluate whether different hardware and software types within an aggregation warrant separate reporting channels as the differing technologies have unique electrical responses.

How the DER aggregation performs will, of course, affect whether data gets reported in the aggregate for particular instances. Refer to the previously mentioned Reliability Guideline for the use of recordings for model verification and event analysis concerning DER. The metering and telemetry mentions in Figure X.XXX are typically market related, but may have a need to be used by the TOP to maintain situational awareness for the bulk system, which is discussed in the coordination section of this white paper. As such, it is important to have the TOP be involved in development of metering and telemetry devices used for the resources aggregated by a DER aggregator.

Studies

Figure S.1 shows the paragraphs from FERC Order No. 2222 that are particularly relevant for the purposes of performing reliability studies with the introduction of the DER aggregator.

Paragraph 99. *"…In response to increased demand for distributed energy resource aggregations for wholesale market participation, some state or local authorities may choose to voluntarily update their distribution interconnection processes to assess the impacts of distributed energy resource aggregations on the distribution system at the initial interconnection stage, while other state and local authorities may not. In the latter scenario, it may be both necessary and appropriate for the RTO/ISO, in coordination with affected distribution utilities, to conduct separate studies of the impact on the distribution system after a distributed energy resource joins a distributed energy resource aggregation."*

Paragraph 99. *"…we expect that modifications to the list of resources in a distributed energy resource aggregation could occasionally indicate changes to the electrical characteristics of the distributed energy resource aggregation that are significant enough to potentially adversely impact the reliability of the distribution or transmission systems and justify restudy of the full distributed energy resource aggregation; therefore, RTOs/ISOs and distribution utilities may perform such aggregation restudies if necessary…"*

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."*

Figure S.1: Relevant Studies Paragraphs

RTO/ISO consideration of DER aggregators should ensure that study boundaries depicting the DER aggregators are well-defined and understood by TPs and PCs. More specifically, if a DER aggregator spans across multiple TP/PC footprints[29], coordination of data, information, models, practices, etc., will have to be updated consistently to ensure the DER aggregator is reflected properly in operational, near-term, and long-term studies. Further, the proliferation of DER aggregators may also impact regional and inter-regional

[29] This is possible to occur through a DER aggregator spanning a single RTO or ISO but the boundary is across two or more areas planned by differing TPs.

planning practices (e.g., underfrequency load shedding programs[30] required under PRC-006[31]). RTOs/ISOs should ensure that data is exchanged between TPs/PCs and used appropriately. Considering these transformative operational models for DER aggregators, model and study quality and fidelity is just important now as it has ever been.

SPIDERWG encourages RTOs/ISOs proactively study the impact DER aggregators have on regional and local transmission systems, specifically assessing the reliability impact these resources have on the BPS. Study results, through ample coordination and communication of identified impacts, should be communicated to both system operators with an eye toward mitigating any impacts DER aggregations might cause.

All entities must coordinate to ensure adequate studies represent the behavior of the DER under a DER aggregator. For example, care should be taken to determine whether the DER can safely participate in the proposed markets through a fully vetted interconnection study. Further, all entities should coordinate and perform adequate studies (coordination of protection settings, operational day-ahead, etc.) to ensure the reliability of the BPS for aggregations operated under DER aggregators. This paradigm shift may also require software vendors to provide adequate tools for TPs and PCs to represent the behavior of DER aggregators.

Further, while production cost modeling is typically not the focus of TPs and PCs, SPDIERWG's recommendations may be relevant for simulation in those practices. Additionally, any dispatch assumptions that come from production cost modeling need to be fully understood by the TP and PC as those dispatches are included in their reliability studies.

Coordination

Figure C.1 shows the paragraphs from FERC Order No. 2222 that are particularly relevant for the purposes of coordination activities with the introduction of the DER aggregator.

[30] SPIDERWG's *Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs* for this particular practice can be found at the RSTC website here: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx
[31] PRC-006-5 is available here: https://www.nerc.com/files/PRC-006-5.pdf

Paragraph 292. *"…each RTO/ISO must coordinate with distribution utilities to develop a distribution utility review process that includes criteria by which the distribution utilities would determine whether (1) each proposed distributed energy resource is capable of participation in a distributed energy resource aggregation; and (2) the participation of each proposed distributed energy resource in a distributed energy resource aggregation will not pose significant risks to the reliable and safe operation of the distribution system. To support this review process, RTOs/ISOs must share with distribution utilities any necessary information and data… about the individual distributed energy resources participating in a distributed energy resource aggregation. In addition, the results of a distribution utility's review must be incorporated into the distributed energy resource aggregation registration process."*

Paragraph 310. *"we… require each RTO/ISO to revise its tariff to (1) establish a process for ongoing coordination, including operational coordination, that addresses data flows and communication among itself, the distributed energy resource aggregator, and the distribution utility; and (2) require the distributed energy resource aggregator to report to the RTO/ISO any changes to its offered quantity and related distribution factors that result from distribution line faults or outages."*

Paragraph 324. *We further note that possible roles and responsibilities of relevant electric retail regulatory authorities in coordinating the participation of distributed energy resource aggregations in RTO/ISO markets may include, but are not limited to: developing interconnection agreements and rules; developing local rules to ensure distribution system safety and reliability, data sharing, and/or metering and telemetry requirements; overseeing distribution utility review of distributed energy resource participation in aggregations; establishing rules for multi-use applications; and resolving disputes between distributed energy resource aggregators and distribution utilities over issues such as access to individual distributed energy resource data.*

Figure C.1: Relevant Coordination Paragraphs

Having clear data exchange processes between the DER aggregators, the distribution utility, transmission entities (primarily TOPs) and the RTO/ISO (which are registered as BAs and RCs) are critical for ensuring reliable operation of the BPS. This includes real-time data exchange, expected performance into future operating conditions (for studies), and data quality/exchange protocols. SPIDERWG recommends tight coordination among DER aggregators, DPs, TPs, TOPs, and other entities across the T-D interface in order to ensure the reliability of the Bulk Electric System. Further, RTOs/ISOs should develop requirements to ensure the DER aggregator has a process to submit uniform information from every individual DER in the aggregation for the purposes of representing the equipment in operational or planning studies. BAs and RCs should ensure performance requirements exist to provide System Operators confidence in the capabilities of DER aggregators such that operators maintain their system awareness. The BAs and RCs should ensure that proper communications and coordination are performed so that implemented requirements are able to meet both transmission and distribution needs. As more DER aggregators come online, SPIDERWG will monitor the impacts and discuss recommended changes in future work. A few topics are mentioned in the section below for such future efforts.

SPIDERWG anticipates that the DER aggregator will, in the efforts of coordination, have multiple different places where data is sent to transmission entities to ensure reliability of the BES.

FERC 2222-A, FERC 2222-B, and Possible Future Rulings

After FERC Order No. 2222, issues such as demand response, opt-outs, and the jurisdiction of state regulators were raised to FERC. The SPIDERWG is not specifically focusing on the content of these subsequent releases other than to reiterate the guidance mentioned above. SPIDERWG recommends RTOs and ISOs to adopt the recommendations contained within the reliability guidelines to ensure that appropriate measures are in place particularly with the inclusion of DER aggregators. SPIDERWG recognizes that the DER aggregator introduced in the releases is not within the current NERC functional model of registered entities. Therefore, in a future with more DERs controlled by a DER aggregator, this could lead to challenges in maintaining essential reliability services, sharing off-line or real-time information for planning or operations, and could introduce security vulnerabilities into the electricity ecosystem. These issues should be considered and addressed in the very near-term. SPIDERWG is willing to provide perspectives on this subject, but is seeking RSTC input on whether to add this to the SPIDERWG work plan.

Recommendations for SPIDERWG Work Plan Additions

FERC Order No. 2222 identified topics considered out-of-scope for Order No. 2222 in Paragraph 362, and industry identified these as areas of concern where future work may be needed. SPIDERWG reviewed these topics and has provided recommendations for future work as well as the applicable group within the RSTC that could lead those efforts (see Table 1).

Table 1: Proposed Future Work

Topic	Deliverable	RSTC Group	Timeline
Impacts on BPS variability and uncertainty due to the introduction of the DER aggregator	White Paper	SPIDERWG	2023+
Recommended practices for modeling DER aggregators (and parameterizing those models) in BPS reliability studies	White Paper	SPIDERWG	2023+
Understanding the BPS planning and operations impacts of DER management systems (DERMS) and other aggregator functions after complete implementation and operation	White Paper	SPIDERWG	2023+
Privacy and cybersecurity concerns for the BPS with the introduction of DERs and DER aggregators	White Paper	SITES	2023+
Sharing data collection and data sharing practices with the introduction of the DER aggregator	White Paper	SPIDERWG	2023+
Technical impacts on the potential NERC registration[32] of the DER aggregator for NERC standards.	Various	Various	TBD

[32] This item's deliverable, RSTC group, and timeline is dependent upon the result of current efforts of SPIDERWG leadership engaging with the RSTC and other NERC groups to see what role SPIDERWG plays in any NERC registration discussion.

White Paper: NERC Reliability Standards Review

Action
Request for RSTC reviewers.

Summary
The increasing penetration of DERs is already having an impact on bulk power system (BPS) planning, operations, and design, and it is paramount that NERC Reliability Standards remain effective and efficient in ensuring an adequate level of reliability for the BPS. As a result, the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) has evaluated the current body of NERC Reliability Standards and the requirements within those standards for their applicability and effectiveness to remain relevant with increasing levels of DERs. This white paper details the findings of the SPIDERWG review and makes recommendations for actions that should be taken to address identified issues. The SPIDERWG is seeking RSTC members to review and provide comment on the white paper.

NERC Reliability Standards Review

NERC System Planning Impacts from DERs Working Group (SPIDERWG)
White Paper – March 2022

Executive Summary

The North American bulk power system (BPS) is experiencing a rapid growth of distributed energy resources (DERs) in multiple regions and is expected to have significant additional growth of DERs in future years. The increasing penetration of DERs is already having an impact on BPS planning, operations, and design, and it is paramount that NERC Reliability Standards remain effective and efficient in ensuring an adequate level of reliability for the BPS. As a result, the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) has evaluated the current body of NERC Reliability Standards and the requirements within those standards for their applicability and effectiveness to remain relevant with increasing levels of DERs. This white paper details the findings of the SPIDERWG review and makes recommendations for actions that should be taken to address identified issues. Appendix A provides additional details on review approach. A well thought out approach to DER integration is needed to continue to ensure adequate levels of BPS reliability. The growing aggregate level of DERs will affect all facets of the operating the BPS – from planning activities to real-time operations to system restoration activities.

The terms "DER" and "aggregate DER" have been used throughout this document, and are used appropriately based on the context of their specific use. This standards review paper in its entirety relates to the aggregate impacts of DERs and in the context of the standards reviewed. The term "aggregate DERs" simply relates to the aggregated effects that DERs can have. In many cases, the term "DER" is more appropriate in specific contexts for this review.

Recommended Standards for Revision

SPIDERWG identified potential gaps and areas for improvements in the standards listed in Table ES.1. The table provides a brief description of the improvement needed. Refer to Appendix A for more details on the review of each specific standard. SPIDERWG assigned a priority to each recommended standard revision based on the impact that these gaps may have on reliable operation of the BPS with increasing levels of DERs. Prioritization is intended to help support the NERC Standards Committee in the development of possible Standard Drafting Teams. The high, medium, and low categories are based on the prioritization of two parallel elements constituting importance and a feasible development timeline. Prioritization is based on the following:

- **High:** These standard revisions should be completed as soon as possible or on a very near-term horizon. As short-term DER penetrations increase across North America, the issues identified are likely to lead to a potential reliability issue.
- **Medium:** These standard revisions should be completed on a mid-term horizon (i.e., within a two-year window). As DER penetrations increase, entities may experience potential reliability issues if the standards identified are not revised to address the issues.

- **Low:** These standard revisions should be completed on a longer-term horizon (i.e., within a three-year window). Gaps and areas for improvement relate to clarity and consistency issues regarding how DERs impact the BPS or are accounted for in the standard requirements.

SPIDERWG recommends that Standard Authorization Requests (SARs) be developed for each project, and will add work plan items to begin development of SARs upon RSTC approval of this white paper. SPIDERWG recognizes that the development of SARs will require coordination with other RSTC groups and will take the initiative to coordinate with those groups, as needed.

Table ES.1: Consider Standards Revisions

Standard	High-Level Description of Outcome	Priority
BAL-003-1.1*	Revise the standard to ensure consistent accounting of DERs in balancing calculations.	Low
EOP-004-4*	Revise the standard to ensure proper reporting of the loss of aggregate DERs to NERC with defined thresholds.	High
EOP-005-3*	Revise the standard to establish telemetry requirements for DERs and/or Distribution Providers (DPs).	Medium
FAC-001-3	Revise the standard to include the DP in the "Applicability" section.	High
FAC-002-2	Revise the standard to ensure responsible entities perform study when aggregate DERs cause material modifications to electricity end-user Facilities.	High
MOD-031-2	Revise the standard to ensure that existing and forecasted DER data is provided by DPs or Transmission Planners (TPs) to the Planning Coordinator (PC) upon request.[1] Allow TPs to be an intermediary to provide data from DPs to the PC.	High
PRC-006-3	Revise R3 of the standard to specify whether net or gross load is required for Under-Frequency Load Shed (UFLS) studies.	Low
TOP-001-4	Revise the Operational Planning Analysis (OPA) and Real-Time Analysis (RTA) definitions to explicitly enumerate aggregate DER or non-Bulk Electric System (BES) generation output levels.	Low
TOP-002-4	Revise the OPA definition to include aggregate DER or non-BES generation output levels.	Low
TOP-003-3	Revise the OPA and RTA definitions to include aggregate DER or non-BES generation output levels.	Low
TOP-010-1(i)	Revise the RTA definition to include aggregate DER or non-BES generation output levels.	Low

* Indicates that the review team also identified the need for a reliability guideline on the general subject.

[1] NERC *Reliability Guideline: DER Forecasting Practices and Relationship to DER Modeling for BPS Planning Studies*, to be published 2022.

Recommended Standards for Future Revisions

SPIDERWG also identified potential gaps and areas for improvement in the standards listed in Table ES.2. However, these issues are much lower priority than those mentioned above and therefore SPIDERWG is not recommended a standards project at this time to address the issues identified. SPIDERWG is documenting these considerations and issues that may warrant possible standards projects as the integration of DER continues. The issues identified in Table ES.2 should be reviewed again after completion of items in Table ES.1 or if these standards are revised in other projects. Refer to Appendix A for more details on specific standards review outcomes.

Table ES.2: Consider Standards Future Revisions

Standard	High-Level Description of Outcome
FAC-003-4	Revise the standard to include facilities between 100kV and 200kV. Ensure proper vegetation management protocols are followed to avoid disruption. Revise to include aggregate DER facilities in the "Applicability" section.
FAC-011-3	Revise the standard to address potential System Operating Limit (SOL) inaccuracies caused by the variability or uncertainty of DERs and the change of power flows at the transmission–distribution interface.
IRO-001-4	Revise the standard requirements focused on managing reliability impacts from aggregate DERs.

Recommended Reliability Guidelines Needed

SPIDERWG identified multiple standards where industry guidance is needed in the areas related to implementation of specific standards. The team considered both NERC reliability guidelines as well as NERC compliance implementation guidance options. The issues identified are general in nature and therefore broader guidance (i.e., reliability guidelines) are more suitable than compliance implementation guidance for the topics identified. Table ES.3 provides a list of standards where reliability guidelines would be useful.

Upon RSTC approval of this white paper, SPIDERWG will add each of the guidelines identified in Table ES.3 to its work plan. SPIDERWG will prioritize these guidelines, as needed, and develop suitable timelines that align with current work plan activities.

Table ES.3: Recommended Reliability Guidelines

Standard	Description of Guidance Needed
BAL-002-3	Reliability guideline on approaches to DER accounting in reserve management.
BAL-003-1.1*	Reliability guideline on managing adequate levels of frequency response with increasing levels of DERs.
BAL-005-1	Reliability guideline on approaches to DER accounting in reserve management.
EOP-004-4*	Reliability guideline on detection and calculation of aggregate DER loss during and after an event to facilitate accurate reporting.

Table ES.3: Recommended Reliability Guidelines	
Standard	**Description of Guidance Needed**
EOP-005-3*	Reliability guideline on coordination and data exchange between the TOP and DP for development of restoration plans, including information regarding aggregate DER levels and expected operating characteristics.
EOP-011-1	Reliability guideline on how load shedding schemes may need to consider the amount of DERs impacted by such load shedding practices to ensure minimal power system impact and that load can be effectively shed without the loss of considerable levels of generation.
IRO-018-1(i)	Reliability guideline for telemetry, communication, data handling capability coupled with data quality issues associated with increasing DER.
MOD-033-1	Reliability guideline providing industry recommended practices for collection and validation of DER and distribution level characteristics should be developed.
PRC-010-2	SPIDERWG is presently working on a white paper emphasizing that Under-Voltage Load Shedding (UVLS) programs should be coordinated with DER ride-through capabilities.
PRC-012-2	Reliability guideline discussing the impact of DERs on Remedial Action Scheme (RAS) design and performance.
PRC-027-1	Reliability guideline discussing the impact of "nuisance" trips of aggregate amounts of DER for BPS faults due to miscoordination of DP-owned protection systems.

* Indicates that the review team also identified the need to revise the standard in addition to developing a guideline.

Recommendation – No Action Needed

SPIDERWG did not identify any actions needed for those standards listed in Table ES.4.

Table ES.4: Standards with No Action Needed					
BAL-001-2	INT-004-3.1**	IRO-017-1	MOD-030-3	PRC-011-0	TPL-007-3
COM-001-3	INT-006-4	MOD-001-1a	PER-003-2	PRC-015-1	VAR-001-5
COM-002-4	INT-009-2.1	MOD-004-1	PER-005-2	PRC-016-1	VAR-002-4.1
EOP-006-3	INT-010-2.1**	MOD-008-1	PER-006-1	PRC-017-1	
EOP-008-2	IRO-002-6	MOD-020-0 **	PRC-001-1.1(ii)	PRC-018-1	
EOP-010-1	IRO-006-5	MOD-025-2	PRC-002-2	PRC-019-2	
FAC-008-3	IRO-008-2	MOD-026-1	PRC-004-5(i)	PRC-023-4	
FAC-010-3	IRO-009-2	MOD-027-1	PRC-005-1.1b	PRC-024-2	
FAC-014-2	IRO-010-2	MOD-028-2	PRC-005-6	PRC-025-2	
FAC-013-2**	IRO-014-3	MOD-029-2a	PRC-008-0	PRC-026-1	

** Indicates that this standard was retired.

Background and Purpose

The SPIDERWG was formed in 2018 as a follow-up to the NERC Distributed Energy Resources Task Force (DERTF) and Essential Reliability Services Working Group (ERSWG).[2] The goal of SPIDERWG is to analyze the increasing penetration of DERs in many areas across North America and develop recommended practices to manage the BPS under these situations. SPIDERWG has published multiple reliability guidelines related to BPS planning aspects with increasing levels of DERs.

In December 2021, SPIDERWG submitted Standard Authorization Requests (SARs) for revisions to NERC MOD-032-1 and TPL-001-5 to address gaps in these standard related to the consideration of DERs. The NERC RSTC endorsed both SARs and these SARs are being presented to the NERC Standards Committee in Q1 2022. These two standards were therefore omitted from the review of standards, as they were recently reviewed in depth by SPIDERWG.

SPIDERWG determined that it would be beneficial to perform a comprehensive technical review of all NERC Reliability Standards to determine if there are any potential gaps or improvements beyond what was identified for its work plan in 2018. This white paper provides the results of the review conducted by SPIDERWG, and covers the majority of currently enforceable standards for potential gaps or improvements. The review is intended to be technical and may not be limited by, nor intends to comment on, existing jurisdictional boundaries between NERC Registered Entities and those under state or other jurisdictions. Where appropriate, the recommendations from this review should be further discussed with applicable regulatory bodies and the associations representing them (e.g., NARUC).

Because of NERC jurisdictional limitations, the identified reliability concerns that potentially arising from increased deployment of DER could be addressed through other means to achieve the same objective of maintaining BPS reliability. One of such means may be IEEE Standards Association (IEEE-SA) projects that complement NERC Reliability Standards with industry consensus standards, recommended practices, and guidelines that often have a higher degree of technical specificity. Examples include IEEE 1547-2018 (Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces), IEEE P1547.2 (Application Guide to IEEE 1547-2018), and P2030.11 (Guide for Distributed Energy Resources Management Systems Functional Specification)[3]. IEEE-SA documents are voluntary in their nature and would require adoption and enforcement by applicable regulatory bodies (e.g., state authorities).

The SPIDERWG acknowledges that the findings in this white paper are limited to the knowledge and experience of its members and that other issues may be discovered as industry and technology continues to evolve and grow. Any such issues may be addressed through the NERC RSTC or NERC Standards

[2] https://www.nerc.com/comm/Other/Pages/Essential-Reliability-Services-Task-Force-(ERSTF).aspx

[3] Other industry activities include:
DER Group Management for Coordinated Operations Across the T&D Interface. EPRI. Palo Alto, CA: December 2019. 3002016174. [Online] https://www.epri.com/#/pages/product/000000003002016174/
TSO/DSO Coordination for DER Management Working Group. EPRI. Ongoing and public working group. Latest materials available at URL https://epri.box.com/v/TSODSOCoordinationWG (password: EPRITSODSOWG)

Committee processes, accordingly. In particular, the SPIDERWG acknowledges that it lacks subject matter expertise in the areas of the CIP, COM, NUC, and PER standards and did not review those standards as part of this activity.

In addition, the concepts of DER aggregators, DER management systems (DERMS), and other concepts introduced in FERC Order No. 2222 introduce additional considerations that should be analyzed by industry stakeholders as they update their interconnection requirements and tariffs to enable these new functions.[4] One potential future consideration is the addition of the DER aggregator to the applicability section of certain standards and/or a clarification that "Generator Operator" includes "DER aggregator". FERC Order No. 2222 could accelerate the participation of DER aggregations in wholesale markets and, thus, make the implementation of some of the recommended actions identified in this white paper more urgent than currently determined. SPIDERWG also has a work product evaluating BPS reliability perspectives of the DER aggregator, and is working to determine its role in providing technical support for these considerations.

[4] https://www.ferc.gov/news-events/news/ferc-opens-wholesale-markets-distributed-resources-landmark-action-breaks-down

BAL Standards

The following is a summary of findings and recommended actions for this body of standards:

- A reliability guideline should be developed, or an existing one expanded, to cover the consistent treatment of DERs across the various BAL standards.
- The NERC Glossary of Terms should be changed to resolve the identified issues across multiple standards.

Table B.1: BAL Standards Review Outcome

Standard	Result of SPIDERWG Review
BAL-001-2	No Action Needed
BAL-002-3	Reliability Guideline
BAL-003-1.1	Revise Standard and Reliability Guideline
BAL-005-1	Reliability Guideline

The following outcomes were identified by SPIDERWG:

- **BAL-002-3 and BAL-005-1: Reliability Guideline**

  The placement of DERs in the various balancing equations (e.g., accounting of impact of DER in the Most Severe Single Contingency or the gathering of data for reporting in Area Control Error (ACE)) cut across a number of standards, so Compliance Implementation Guidance is not the best vehicle to use. The standards themselves do not need revision for DERs, but a consistent approach regarding DERs (e.g., counting DERs either explicitly as resources or implicitly as load modifiers) is needed that would be applicable across all standards. New reliability guidelines or revisions to existing guidelines (e.g., Reserves Management) would be helpful. NERC Glossary changes or additions may also be an effective way to implement consistent treatment across multiple standards in the future.

- **BAL-003-1.1: Revise Standard and Reliability Guideline**

  The standard is currently under revision, but not necessarily focused on aggregate DER concerns. FERC Form 714 linkage is proposed to be removed, but the reporting of net generation and net load will be affected by how DERs are counted and the resultant apportionment of Interconnection Frequency Response Obligation (IFRO) to each Balancing Authority (BA). Standard language would need to address the reporting of net generation and net load, which indicates a need for standard revisions.

  A reliability guideline, not specific to BAL-003, on how DER should be counted (a reduction in load or explicit inclusion as resource capacity) should be written. The existing reliability guidelines focused on balancing should also be reviewed to address counting of DERs consistently. One of those guidelines is currently under triannual revision by the NERC Resources Subcommittee, so input to should be directed to its originating group, the Resources Subcommittee.

CIP Standards

The NERC CIP Standards were not reviewed.

COM Standards

The following is a summary of findings and recommended actions for this body of standards:

- COM-001-3 and COM-002-4 Standards were reviewed and no actions are needed because the increase in DERs will not affect applicability or implementation of these standards.
- The addition of a DER aggregator may require further analysis and possible modifications to the COM Standards at a later time.

Table B.2: COM Standards Review Outcome

Standard	Result of SPIDERWG Review
COM-001-3	No Action Needed
COM-002-4	No Action Needed

EOP Standards

The following is a summary of findings and recommended actions for this body of standards:

- A reliability guideline should be developed for EOP-004-4 regarding how to detect and calculate aggregate DER loss during and after an event.
- A reliability guideline should be developed for EOP-005-3 regarding the coordination and data exchange between the TOP and DP in the development of restoration plans.
- A reliability guideline should be developed for EOP-011-1 regarding how to coordinate manual or automatic load shedding schemes with DERs.
- EOP-004 should be revised to include thresholds for reporting of aggregate DER loss during and after an event.
- EOP-005 should be revised to include data and monitoring requirements on the DP and/or DERs for inclusion of DER into system restoration plans.

Table B.3: EOP Standards Review Outcome

Standard	Result of SPIDERWG Review
EOP-004-4	Revise Standard and Reliability Guideline
EOP-005-3	Revise Standard and Reliability Guideline
EOP-006-3	No Action Needed
EOP-008-2	No Action Needed

Table B.3: EOP Standards Review Outcome	
Standard	**Result of SPIDERWG Review**
EOP-010-1	No Action Needed
EOP-011-1	Reliability Guideline

The following outcomes were identified by SPIDERWG:

- **EOP-004-4: Revise Standard and Reliability Guideline**

  Recent large-scale disturbances (e.g., the August 2019 disturbance in the United Kingdom)[5] have demonstrated that unexpected loss of DERs during BPS faults can compromise reliable operation of the BPS. Despite potential impact to reliable operation, EOP-004-4 does not currently require reporting by DPs, TOPs, BAs and RCs of the loss of aggregate DER to NERC. SPIDERWG recommends that a Standard drafting team review and revise EOP-004-4 to require reporting, including threshold for reporting, of the loss of aggregate DER to NERC. Additionally, a reliability guideline addressing detection and calculation of aggregate DER losses should be developed to help support accurate reporting. The guideline could leverage materials from NERC disturbance reports and other industry efforts such as the NPCC DER BES Impact Reporting Form.

- **EOP-005-3: Revise Standard and Reliability Guideline**
  Under the current applicability section of EOP-005-3, the requirements for resource integration into the plan, in most cases, fall to the TOP or the TO. Typically these entities receive only load data from the DP, not the operating characteristics of underlying resource control systems. The TOP or TO are therefore frequently unable to confidently predict resource response to system conditions.

  If DERs are to be accepted to participate as Blackstart Resources in a system restoration plan, there will be a need to study the switching path from the DER to the BPS system restoration plan objective that is being supported. Without access to additional data and operating characteristics for modeling the DER, the studies required under EOP-005-3 would provide only an estimate of the lower voltage system response to an event, steady-state and dynamic simulations, bringing into question the accuracy of the studies. As referenced by other standard DER review teams, historical events have shown that the lack of data and modeling from distribution systems has resulted in inaccurate assessments of transmission system performance and contingency responses. Some contributing factors to events were a lack of visibility into the lower voltage systems and understanding of the distribution system resource controls responses to transmission system contingencies.

  With the integration of DER as a Blackstart Resource in a system restoration plan, consideration of inverter-based technologies (IBT) or an aggregate of resources including a mix of IBT and traditional capacity resources, makes it critical to evaluate the transmission system contingency response prior to accepting the resource into the system restoration plan. Understanding the resource's expected

[5] Investigation into 9 August 2019 power outage | Ofgem

response is particularly true in the early stages of restoration, when the transmission system is considered weak, and frequency control as well as voltage control can be challenging for system operations, with frequency and voltage excursions beyond the normal range being typical.

EOP-005-3 Requirements R1.4, R6, R7 and R11 all require data to successfully comply with the Standard. The ability to obtain this information in a vertically integrated environment may not present challenges, but in market environments, RTO's/ISO's/TOP's past experience has shown difficulty in obtaining new technology or resource mix data and operating characteristics when not enforceable under a Standard. Integration of Demand Response (DR) in the Forward Capacity Market is an example. DR resides on the distribution system and causes data concerns for the RTO/ISO/TOP, around potential real-time dispatch of DR on the wrong side of a constraint.

The creation of a reliability guideline was discussed during the SPIDERWG review. Restoration is too critical to encounter data/operating characteristic issues during plan analysis and implementation to ensure reliability. As shown above, the data concerns for DR are likely to be encountered with DER. Thus, the onus must be placed on the Distribution Provider to provide data/operating characteristics of the resources within its distribution system to the TOP and TO in the development of a system restoration plan. The reliability guideline for the topic in this standard is related to the practices in sharing that information and not addressing the critical need for such information to be shared for DER participating in a system restoration plan.

- **EOP-011-1: Reliability Guideline**
  SPIDERWG recommends the development of a reliability guideline to develop and disseminate recommended practices related to EOP-011-1 emergency plans that include DER operations and considerations. Increasing penetrations of DERs will require modifications to previously used TOP and RC operating practices. Regarding the development of emergency operation plans the expectation of considerable levels of DERs within the impacted power system requires consideration. The operational state of aggregate levels of DERs, particularly the level of controlled real power curtailment during an emergency, need to be clarified as to leverage all available power system assets to less or avoid impacts from such emergencies. Additionally, the requirement to avoid overlap between automatic and manual load shedding schemes needs to consider the amount of DERs impacted by such load shedding practices to ensure minimal power system impact and that load is effectively shed without the loss of considerable levels of generation.

FAC Standards

The following is a summary of findings and recommended actions for this body of standards:

- FAC-001-3 should be revised to include the DP in the Applicability section.
- FAC-002-2 should be revised to indicate that if DER aggregations result in "material modifications" to electricity end-user Facilities, a study of the "material modifications" is required.
- FAC-003-4 should be revised to include facilities between 100 kV and 200 kV.

- FAC-011-3 should be revised to address the concerns of SOL inaccuracy brought by the uncertainty from increasing DER penetration.

Table B.4: FAC Standards Review Outcome

Standard	Result of SPIDERWG Review
FAC-001-3	Revise Standard
FAC-002-2	Revise Standard
FAC-003-4	Revise Standard
FAC-008-3	No Action Needed
FAC-010-3	No Action Needed
FAC-011-3	Revisions May Be Needed in Future
FAC-013-2	No Action Needed
FAC-014-2	No Action Needed

The following outcomes were identified by SPIDERWG:

- **FAC-001-3: Revise Standard**

  There is no explicit reference to DERs in the standard. A revision is needed to address the impact of DERs on the BES. The DP should be included in the "Applicability" section. Requirements should be modified to include the DP, considering the following options:

  - R1, for a specified level of aggregate generation (a level to be discussed further);
  - R2, for a specified level of aggregate DER installations, to trigger a reliability impact study of affected the system;
  - R3 or R4, to ensure appropriate coordination studies be performed.

  Additionally, a discussion of the impact of DERs on the BES could be added as a separate item in the list of supplemental material that is presented at the end of the document and linked to Requirement #3. In all cases, some technical guidance (e.g., compliance implementation guideline or a reliability guideline) will be needed for use by DPs in coordination with TOs.

- **FAC-002-2: Revise Standard**

  SPIDERWG recommends that a Standard Drafting Team review and modify FAC-002-2, as necessary, such that the Standard requires the study of material modifications to electricity end-user Facilities related to increasing levels of aggregate DERs. Recent studies and presentations to SPIDERWG indicate that if aggregate DER is integrated without adequate interconnection studies, reliable operation of the BES is likely to be impacted (e.g., contingencies worsened by aggregate DER tripping off-line). It should be noted that NERC Project 2020-05 is addressing the need for clarifications to the term “materially modify”; however, SPIDERWG recommends that this be extended to the concepts of material modifications for “electricity end-user Facilities” referenced in FAC-002. The current or future standard drafting team may seek to define these terms in the NERC Glossary, if necessary.

In the future, SPIDERWG could develop guidance material (e.g., reliability guidelines or compliance implementation guidance) to support implementation of FAC-002, specifically related to performing aggregate DER studies.

- **FAC-003-4: Revise Standard**

  SPIDERWG recommends modifications to the standard to include facilities between 100kV and 200kV. The SDT currently reviewing FAC-003-5 is leaning towards removing SOLs and IROLs from the latest standard under review. DER facilities are connected at a threshold below 200kV. Ensuring proper vegetation management protocols are followed to avoid disruption of anticipated flow of power to the point of interconnection will be critical to prevent disruptions capable of cascading events. Adding aggregate DER facilities to the applicability of this standard, is needed under future conditions of increasing levels of DERs.

- **FAC-011-3: Revisions May Be Needed in the Future**

  The main concern is whether increasing penetration of DERS will affect the change of power flows at the transmission-distribution interface, which is not captured by R2 and R3 requirements, affecting the output of the SOL calculation. The uncertainty of DERs will have a larger impact with increasing penetration of DERs; therefore, a new methodology may be needed to account for the uncertainty of DERs. A future revision should consider the response of DER following a single contingency in Requirement R2.3. Increasing penetration of DERs will likely require the RC to change the methods of determining SOLs listed in R3.

INT Standards

The following is a summary of findings and recommended actions for this body of standards:

- No actions are needed with any of the INT standards.

Table B.5: INT Standards Review Outcome	
Standard	**Result of SPIDERWG Review**
INT-004-3.1	No Action Needed
INT-006-4	No Action Needed
INT-009-2.1	No Action Needed
INT-010-2.1	No Action Needed

IRO Standards

The following is a summary of findings and recommended actions for this body of standards:

- IRO-001-4 should be revised in the future to consider the addition of the DER aggregator to the Applicability section of the standard, and/or to the clarification that "Generator Operator" includes "DER aggregator".
- A reliability guideline for IRO-018-1(i) should be developed to address the lack of observability and availability of real-time DER data and performance. The reliability guideline should clarify the telemetry requirements and communication capability as well as the increases in data handling capability and data quality issues with increasing DERs.

Table B.6: IRO Standards Review Outcome

Standard	Result of SPIDERWG Review
IRO-001-4	Revisions May Be Needed in the Future
IRO-002-6	No Action Needed
IRO-006-5	No Action Needed
IRO-008-2	No Action Needed
IRO-009-2	No Action Needed
IRO-010-2	No Action Needed
IRO-014-3	No Action Needed
IRO-017-1	No Action Needed
IRO-018-1(i)	Reliability Guideline

The following outcomes were identified by SPIDERWG:

- **IRO-001-4: Revisions May Be Needed in the Future**
SPIDERWG recommends that any future revisions to the Standard consider adding the DER aggregator to the applicability section of the Standard, and/or clarifying that "Generator Operator" includes "DER aggregator". Any future drafting efforts for a guideline or revision of this standard could ensure that the reliability of the grid is not compromised by the impact of DER due to an RC's coordination efforts from a transmission or distribution perspective. SPIDERWG also recommends that future conditions be reviewed at a later time to determine if a reliability guideline providing guidance to the RC in issuing Operating Instructions to the appropriate entities on the Distribution System as well as maintaining the reliability of the BPS.

SPIDERWG recommendations are primarily based on engineering judgement and not on a thorough body of research. Since the research in this area is still evolving, this initial evaluation is based on the following observations:

1) Neither the entity Generator Operator nor the Distribution Provider apply to DER aggregators that combine resources which do not meet FERC/NERC definition of the Bulk Electric System (BES).
2) The NARUC Resolution Recommending State Commissions Act to Adopt and Implement Distributed Energy Resource Standard IEEE 1547-2018 resolved at the 2020 Winter Policy Summit by the National Association of Regulatory Utility Commissioners[6] may lead to increasing deployment of communication-ready DER which, accelerated by the FERC Order 2222[7], may increase DER integration into DER management systems (DERMS) that may participate in grid operations via a DER aggregator.
3) Any DER aggregation larger than 20-75 MVA[8] may impact BES reliability if a Reliability Coordinator is not able to direct actions or issue operating instructions that the DER aggregator shall comply with.
4) Some evolving specifications of bulk system reliability functions that DER aggregators may provide across the T&D interface are presented in some industry reports.[9]

- **IRO-018-1(i): Reliability Guideline**

  In its review, SPIDERWG identified this standard may need some guidance to consider the impact of DER penetration in the set of data quality checks used for Real-time Assessments. The standard requires that the RC develop and implement an operating process or an operating procedure to address the quality of the real-time data necessary to perform its real-time monitoring and Real-time Assessments. Increasing amounts of DER will eventually necessitate accurate measuring of real-time DER data. This will require telemetry and communication capability as well as increases in data handling. It is anticipated that the monitoring of real-time DER data will have data quality issues due to the variability and differences associated with DERs. With consideration of increasing levels of DER on the system and the current lack of wide-spread observability and availability of real-time data for DER, it is anticipated data quality of real-time DER is questionable. SPIDERWG recommends a reliability guideline be written to assist RCs in producing data quality checks for aggregate DER.

MOD Standards

[6] Available online at https://pubs.naruc.org/pub/4C436369-155D-0A36-314F-8B6C4DE0F7C7
[7] https://www.ferc.gov/news-events/news/ferc-opens-wholesale-markets-distributed-resources-landmark-action-breaks-down
[8] Magnitude to be further specified along with any other qualifiers to such a threshold.
[9] Prominent reports are:
- Common Functions for DER Group Management, Third Edition. EPRI, Palo Alto, CA: 2016. 3002008215https://www.epri.com/research/products/000000003002008215
- DER Group Management for Coordinated Operations across the T&D Interface. EPRI, Palo Alto, CA: 2019. 3002016174
- DER Group Management for Coordinated Operations across the T&D Interface. EPRI, Palo Alto, CA: 2020 (In publication). 30020XXXXX

The following is a summary of findings and recommended actions for this body of standards:

- MOD-032 was excluded from this review. The NERC RSTC approved a MOD-032 SAR developed by SPIDERWG at the RSTC December 2021 meeting.
- MOD-031-2 should be revised to allow for the PC to obtain existing and forecasted DER information from DPs or TPs. The TP should have the ability to act as an intermediary to provide data from DPs to the PC.
- A reliability guideline should be developed providing industry recommended practices for validation of DERs in MOD-033-1.

Table B.7: MOD Standards Review Outcome

Standard	Result of SPIDERWG Review
MOD-001-1a	No Action Needed
MOD-004-1	No Action Needed
MOD-008-1	No Action Needed
MOD-020-0	No Action Needed (retired)
MOD-025-2	No Action Needed
MOD-026-1	No Action Needed
MOD-027-1	No Action Needed
MOD-028-2	No Action Needed
MOD-029-2a	No Action Needed
MOD-030-3	No Action Needed
MOD-031-2	Revise Standard
MOD-033-1	Reliability Guideline

The following outcomes were identified by SPIDERWG:

- **MOD-031-2: Revise Standard**
  SPIDERWG recommends adding a requirement to MOD-031 that DPs and TPs are required to provide existing and forecasted DER data when the PC determines a need[10,11]. TPs should be allowed

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

[11] DER Forecasting Practices and Relationship to DER Modeling for BPS Planning Studies. Reliability Guideline. NERC. Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/2_1_Reliability_Guideline%20_DERForecasting-ResponseToComment_SPIDERWG_clea1.pdf

to be an intermediary to provide data from DPs to the PC. Because it is becoming critical to know how much actual demand is on the system given the amount being served by embedded generation without specific language reflecting DERs[12] and how to address them, reliability will be reduced by increasing levels of DERs. The current structure of MOD-031 has a PC request information of entities, and this requirement would have the TP act as an intermediary to the DP for PC requests for forecasted DER information.

- **MOD-033-1: Reliability Guideline**
  MOD-033 focuses on PCs developing a process for and performing system model validation. The standard does not prescribe a specific method or procedure for the validation. Therefore, PC model validation practices may need to be adapted over time as more DERs come on-line; however, the standard does not need a revision at this time. PCs should ensure that aggregate DER is appropriately modeled in system model validation cases.

  A reliability guideline for providing industry recommended practices for system model validation, inclusive of aggregate DER representation in the MOD-033-1 should be developed. For dynamic validation, in particular, fast recording data of aggregate DER response will be needed. How to collect and validate aggregated responses of DER could be addressed in the reliability guideline. Discussion is warranted for determining how to validate distribution level characteristics given the measurement equipment at the transmission level.

NUC Standards

The NERC NUC Standards were not reviewed as part of the SPIDERWG review process.

PER Standards

The following is a summary of findings and recommended actions for this body of standards:

- No actions are needed with any of these standards.

Table B.8: PER Standards Review Outcome

Standard	Result of SPIDERWG Review
PER-003-2	No Action Needed
PER-005-2	No Action Needed
PER-006-1	No Action Needed

PRC Standards

The following is a summary of findings and recommended actions for this body of standards:

[12] MOD-031 calls out “Demand-side Management” whose definition is “All activities or programs undertaken by any applicable entity to achieve a reduction in Demand.” A reading of this definition includes generation sources as they offset Demand, or “the rate at which electric energy is delivered to or by a system or part of a system.” The SPIDERWG review of this standard calls for greater specificity to be added to this standard.

- The standards listed in the table that required no action were focused on transmission level system protection settings, therefore they are not applicable to distribution system or DERs. SPIDERWG acknowledges that increasing levels of DERs will change system dynamics (particularly short circuit dynamics), and protection systems need to account for this. The present construct for protection system coordination and current industry practices in this area may not be well-suited to handle the impacts to the BPS from rapidly increasing DER levels in some areas.

Table B.9: PRC Standards Review Outcome	
Standard	**Result of SPIDERWG Review**
PRC-001-1.1(ii)	No Action Needed
PRC-002-2[13]	No Action Needed
PRC-004-5(i)	No Action Needed
PRC-005-1.1b	No Action Needed
PRC-005-6	No Action Needed
PRC-006-3	Revise Standard
PRC-008-0	No Action Needed
PRC-010-2	Reliability Guideline (White Paper)
PRC-011-0	No Action Needed
PRC-012-2	Reliability Guideline
PRC-015-1	No Action Needed
PRC-016-1	No Action Needed
PRC-017-1	No Action Needed
PRC-018-1	No Action Needed
PRC-019-2	No Action Needed
PRC-023-4	No Action Needed
PRC-024-2	No Action Needed
PRC-025-2	No Action Needed
PRC-026-1	No Action Needed
PRC-027-1	Reliability Guideline

[13] The requirement 5.1 is written generically enough and allows PC/TP to require DDR at the BES bus where response of aggregate DER to system disturbances may be recorded.

The following outcomes were identified by SPIDERWG:

- **PRC-006-3: Revise Standard**

  Recent studies by ISO-NE and CAISO have demonstrated the importance of modeling gross load and aggregate DER in under frequency load shedding (UFLS) simulations to ensure representation of the actual behavior of the BPS. In PRC-006-3 R3, however, the term "load" is used, not "Load" as defined in the NERC Glossary of Terms, allowing net load to be modeled in UFLS simulations.

  To ensure that gross load is modeled, a Standard Drafting Team should modify PRC-006-3 R3 to change the term "load" to "Load", which references gross load. Further, R3 only uses the term “generation”, which may lead to ambiguity in terms of whether aggregate DER should be modelled. A Standard Drafting Team should therefore revise R3 to require the use of “data consistent with that provided in accordance with the MOD-032 standard”, which is currently undergoing a process to initiate a SAR for MOD-032-1. This approach is consistent with that of TPL-001-5.1 R1. Similarly, a Standard Drafting Team should revise R6 to ensure that the UFLS database is “consistent with that provided in accordance with the MOD-032 standard”.

  SPIDERWG has developed a reliability guideline[14] on this topic specifically to help industry understand these concepts as well as provide best practices on the study and implementation of UFLS systems with DER. However, the guideline is not sufficient to address the issues identified in the standard. Therefore, standard revisions are still needed to for consistency and correct planning practices to meet the purpose of the standard.

- **PRC-010-2: Reliability Guideline (White Paper)**

  SPIDERWG determined that PRC-010-2 does not currently require revisions due to the impacts of aggregate DER. PRC-010-2 R1.2 requires that UVLS Programs are “integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, auto-reclosing, Remedial Action Schemes, and other under voltage-based load shedding programs.” Since January 2019, SPIDERWG has not been presented with a study nor evidence indicating UVLS programs are not currently coordinated with DER protection and control ride-through capabilities.

  SPIDERWG will continue its work plan to deliver a white paper to the RSTC on the importance of coordinating UVLS with “other protection and control systems,” including, but not limited to, transmission line protection, auto-reclosing, Remedial Action Schemes, other under voltage-based load shedding programs, and DER ride through capability. The white paper will also emphasize that TPs and PCs should consider the performance of aggregate DERs when developing UVLS Programs.

- **PRC-012-2: Reliability Guideline**

  A reliability guideline discussing the impact of DERs on remedial action scheme (RAS) design and performance should be created. This Standard requires a process of implementation and periodic assessment of RAS. If any deficiencies are identified either during an assessment or an event, the

[14] Available here: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx

development and implementation of a Corrective Action Plan is required. The existing requirements do not need to change with increasing levels of DERs. However, as the RAS may include tripping/shedding of a large amount of load the loss of DERs alongside the load may have an impact on BPS reliability. This is due to the implemented RAS tripping feeder breakers in a distribution substation, rather than operability of demand-only breakers. This potential reliability impact increases in geographical areas with high penetration of DERs. Even if the RAS is not configured to shed load, it is necessary that design and performance of RAS considers interactions with DERs, especially when penetration of DERs is high. As such, the SPIDERWG recommends a reliability guideline be developed on the impacts of DERs on RAS schemes.

- **PRC-027-1: Reliability Guideline**

  A reliability guideline discussing the impact of nuisance trips of aggregate amounts of DER for BPS faults due to lack of coordination of DP-owned protection systems should be created[15]. The purpose of PRC-027 is to maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements such that those Protection Systems operate in the intended sequence during Faults. The standard applies to TOs, GOs, and to a limited extent also to DPs that own Protection Systems that are installed to detect and isolate Faults on BES Elements. The limited applicability to DPs could lead to a coordination gap with regard to DP-owned protection systems that may be configured such that they inadvertently trip aggregate amounts of DER for BPS faults[16]. Examples may include undervoltage relays configured more sensitive than allowed per IEEE 1547-2018 and distribution-connected synchronous generator overcurrent relays that are not coordinated adequately with expected dynamic response of these resources to BPS faults. SPIDERWG's findings urge the creation of a reliability guideline discussing the coordination of Protection Systems to reduce any nuisance trips of aggregate amounts of DER.

TOP Standards

The following is a summary of findings and recommended actions for this body of standards:

- The OPA and RTA definitions in the NERC Glossary of Terms should be changed as part of standards revisions to explicitly include aggregate DER or non-BES generation for all TOP standards.

Table B.10: TOP Standards Review Outcome	
Standard	**Result of SPIDERWG Review**
TOP-001-4	Revise Standard
TOP-002-4	Revise Standard
TOP-003-3	Revise Standard

[15] The IEEE P1547.2 Draft 5.1 and its section 6.2.1.5 on "Considerations when Setting Protection Devices in Distribution Utility Equipment with DER Ride-Through" can be used as a starting reference when drafting the NERC Reliability Guideline.

[16] The concern here is *not* about coordination of DP relay settings for *faults on distribution circuits* as current research has not indicated that distribution relays tripping following distribution faults would result in significant loss of aggregate DERs large enough to negatively impact reliability of the BES.

Table B.10: TOP Standards Review Outcome	
Standard	**Result of SPIDERWG Review**
TOP-010-1(i)	Revise Standard

SPIDERWG in its review identified the following:

- **TOP-001-4, TOP-002-4, TOP-003-3, and TOP-010(i): Revise Standard**
  All four TOP standards refer to either an Operational Planning Analysis (OPA) or Real-Time Assessment (RTA), or both. These standards require applicable entities to consistently perform OPAs[17] and RTAs.[18]

  Not accurately accounting for aggregate DER levels with a reasonable allocation of their connection points to the BPS could affect the quality and accuracy of OPAs and RTAs. SPIDERWG recommends revising the OPA and RTA definitions in the NERC Glossary of Terms to explicitly include aggregate DERs (and non-BES generation output levels) as a component of both the OPA and RTA definitions. The definitions of OPA and RTA both state that the assessments must, at a minimum, include inputs of "load", "load forecast", and "generation output levels". Both net load quantities and BPS generation output (and forecast) levels are affected as the penetration of DERs increases since DERs offset net loading and consequentially affect the amount of on-line BPS generation. Not accounting for both the steady-state and dynamic behavior of DERs will likely have an increasingly adverse impact on the quality of OPAs and RTAs in the future.

  As demonstrated in the August 9, 2019 grid disturbance in the United Kingdom,[19] aggregate DER can trip off-line during BPS fault and contingency events, impacting the overall performance of the BPS and possible operation of safety nets such as underfrequency load shedding. The Palmdale Roost, Angeles Forest, and San Fernando BPS disturbance events in the Southern California area have all included around 100 MW of DER tripping off-line for BPS faults as well.[20] Further, inclusion of aggregate levels of DERs in OPAs and RTAs may impact System Operating Limits. As "load", "load forecast", and "generation output levels" are not defined in the NERC Glossary of Terms, they are subject to interpretation (i.e., entities can decide for themselves whether to include or exclude the aggregate amounts of DERs in their assessments).

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[17] Operational Planning Analysis (OPA): An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)

[18] Real-time Assessment (RTA): An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

[19] https://www.ofgem.gov.uk/system/files/docs/2019/09/eso_technical_report_-_final.pdf

[20] https://www.nerc.com/pa/rrm/ea/Pages/April-May-2018-Fault-Induced-Solar-PV-Resource-Interruption-Disturbances-Report.aspx
https://www.nerc.com/pa/rrm/ea/Pages/July_2020_San_Fernando_Disturbance_Report.aspx

In TOP-002-4, Requirement R4.1 includes "expected generation resource commitment and dispatch" and Requirement R4.3 includes "demand patterns" that should also be inclusive of aggregate levels of DERs since they will affect both. Requirement R4 should be updated to account for DER impacts. The SPIDERWG recommends the standard revisions and glossary term updates be made to ensure the impact of aggregate DERs are covered by the OPAs and RTAs.

TPL Standards

The following is a summary of findings and recommended actions for this body of standards:

- The TPL-001-5 standard was not considered in this effort since the SPIDERWG recently developed a white paper on a detailed review of the standard that was approved by the NERC RSTC. Further, the RSTC approved the SPIDERWG SAR covering the white paper's topics in the RSTC December 2021 meeting.
- SPIDERWG also reviewed TPL-007-3 and determined that no actions are needed.

Table B.11: TPL Standards Review Outcome

Standard	Result of SPIDERWG Review
TPL-007-3	No Action Needed

VAR Standards

The following is a summary of findings and recommended actions for this body of standards:

- No actions are needed for either standard.

Table B.12: VAR Standards Review Outcome

Standard	Result of SPIDERWG Review
VAR-001-5	No Action Needed
VAR-002-4.1	No Action Needed

SPIDERWG identified a possible gap regarding BPS voltage control as the penetration of DERs in conjunction with growing amounts of non-BES BPS-connected inverter-based resources. An increasing reliance of non-BES resources, even only under certain hours of the year, could pose significant challenges for Transmission Operators to manage BPS voltages since limited resources would be required to meet a voltage schedule and operate in automatic voltage control. Without NERC Reliability Standards driving this performance, industry will need to rely on local interconnection requirements to ensure this capability. Further, under high DER penetrations, the BPS may be stressed to have sufficient reactive power capability to support BPS voltages; reliance on accurate planning assessments will be critical and will also require accurate modeling of aggregate amounts of DERs to identify these possible operating conditions. While there are presently no identified issues with the VAR-001 or VAR-002 standards, SPIDERWG would like to recognize the issue presented here; however, SPIDERWG does not have a recommended solution as this is more of a jurisdictional issue that needs to be addressed by NERC.

Appendix A: Review Approach

The SPIDERWG Coordination sub-group performed a comprehensive review of the NERC Reliability Standards to identify any possible reliability gaps or areas of improvements with the existing standards as the penetration of DERs continues to increase across North America. The review team documented its findings in detailed review sheets and consolidated those reviews into the white paper presented here. A total of 77 of the 96 NERC Reliability Standards were reviewed. The NUC were not reviewed because they are not relevant to DERs, and the CIP standards were not reviewed because SPIDERWG does not have security-related expertise. Lastly, MOD-032 and TPL-001 were not reviewed as those standards have already been reviewed in great depth by SPIDERWG recently.

A review template was developed by the team to cover the most relevant and important information that the reviewers should consider during the review. The template provided operations under each question in order to maintain a consistent review. However, a comments section at the end was also provided for reviewers to elaborate on any issues identified. The questions posed to the reviewers are provided here.

Review Outcomes:

1. What is the outcome of this review?

Review Details:

2. Does the standard require any revisions?
3. Is Compliance Implementation Guidance needed to provide examples for implementing the standard (i.e., how to be compliant with the requirement(s) of the standard)?
4. Is Reliability Guideline needed to provide industry recommended practices related to the standard?

Items Considered during Review:

5. Should the standard Applicability section be updated to consider aggregate DERs?
6. If the standard uses the terms "Load" or "Demand", are these terms still clear with the consideration of DERs so that no changes to the standard requirements are needed?
7. Are the standard requirements clear regarding how to account for DERs? (e.g., in planning, operating, modeling, and/or design activities)
8. Will the effectiveness of the standard be affected by increasing levels of DERs?
9. Would the collection of DER data affect the implementation of the standard (i.e., would the ability to gather DER data affect the ability to fulfill the purpose of the standard)?
10. Will the increasing penetration of DERs require entities to change the methods they use to implement the standard requirements?
11. Other Comments

Contributors

NERC gratefully acknowledges the invaluable 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 SPIDERWG.

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To: NERC Reliability and Security Technical Committee (RSTC)

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

Date: February 8, 2022

Subject: NATF Periodic Report to the NERC RSTC (March 2022)

Attachments: NATF External Newsletter (January 2022)

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, which is also available on our public website: www.natf.net/news/newsletters.

NATF Supply Chain Risk Management Activities and ERO Support

Much progress has been made toward supply chain security since 2017 when, in response to the directives in Federal Energy Regulatory Commission (FERC) Order 829, the NERC board asked the North American Transmission Forum (NATF) and others in industry to develop and share "white papers" addressing best and leading practices in supply chain management. The NATF's ongoing supply chain work has continued to address the NERC board's resolution with a focus on security solutions. The ERO and the NATF have common objectives but different roles and capabilities. Over the past several years, our organizations have coordinated to align respective efforts in an ever-more complementary fashion.

The NATF provides confidential venues for members to share information and work toward excellence in reliability, resilience, and security. It follows that NATF's supply chain work has been pursued from the perspective of security excellence. The NATF's work has complemented the efforts of the ERO Enterprise (ERO) as the ERO has worked with entities on meeting compliance. Together, the ERO and the NATF have been working to memorialize the concept that a focus on security can meet the requirements of compliance through the ERO's endorsement of implementation guidance and recognition by the NERC board.

During the first week in February, the NATF submitted two supply chain CIP-013 compliance implementation guidance documents to NERC for ERO endorsement. With endorsement, industry can apply the methods described in the documents (the NATF supply chain model, criteria, and questionnaire) with some assurance they are following the right path for compliance in ERO monitoring and testing activities. During the recent February NERC BOT meeting, Tom Galloway, the NATF CEO, presented our NATF efforts on supply chain to the NERC board of trustees.

Facility Ratings

With strong support and encouragement from the NATF board and member company leadership, NATF members, representing approximately 84% of the total transmission mileage at 100 kV and above in the United States and Canada, are actively working to enhance their facility ratings practices, processes, and controls. The NATF is currently compiling results from its third information collection from members to track ongoing status of practices implementation and will soon provide an updated summary report to ERO leadership. As noted in the attached newsletter, the NATF has updated its practices document to incorporate a risk methodology to prioritize implementation of the practices based on relative facility risk and likelihood of ratings errors.

NATF-ERO Leadership Meetings

NATF and ERO leadership meet periodically to discuss collaborative work and industry topics. The most recent call on January 14 included discussions on supply chain, grid security emergencies, ambient adjusted ratings, facility ratings, cold-weather event report, climate change, reliability assessments, inverter performance, and 6 GHz spectrum. These meetings continue to evolve in both attendance and benefit. While early sessions began with NATF and NERC staff only, these meetings now include NATF board members and Regional Entity CEOs.

FERC NOPR on Internal Network Security

FERC recently proposed to strengthen Critical Infrastructure Protection (CIP) Reliability Standards by requiring internal network security monitoring (INSM) for high and medium-impact bulk electric system cyber systems. The Notice of Proposed Rulemaking (NOPR) proposes to direct NERC to develop and submit new or modified Reliability Standards to address a gap in the current standards. NATF and its members will begin discussions on how we can assist our members in understanding the proposed rulemaking and to implement such monitoring.

North American Transmission Forum External Newsletter

January 2022

Annual Supply Chain Criteria and Questionnaire Revision Process Underway

The NATF is commencing the annual revision process for the “NATF Supply Chain Security Criteria” and the “Energy Sector Supply Chain Risk Questionnaire.” The revision process, the criteria, and the questionnaire are posted on the NATF’s public Supply Chain Cyber Security Industry Coordination site. The process is open to industry, suppliers, regulators, and other stakeholders.

Input on the criteria and questionnaire can be submitted to supplychain@natf.net until close of business February 18 for consideration in the 2022 review cycle.

As the criteria and questionnaire are expected to be the basis for information included in a potential central library, it is important that the information you need to conduct risk analyses is included.

As a reminder: *The criteria and questionnaire capture supplier information important to the electric sector for conducting risk assessments while keeping the amount of data received to a manageable level. The criteria are also verifiable. They are mapped to the National Institute of Standards and Technology (NIST) framework; and while NIST does not have a third-party certification or assessment available, the criteria are also mapped to other security frameworks that are certified or assessed by a qualified third-party. Note that while there is not a single security framework that addresses all criteria, including NIST, most can be verified by obtaining a combination of certifications and/or assessments.*

Central Library for Supply Chain Risk Information

The concept of a central library, or repository, provides for supply chain risk information and resources to be available in one secure location, to streamline suppliers’ ability to provide information and enable industry entities to identify and mitigate supply chain risks effectively and efficiently.

Discussions on whether a central library could be a viable solution for accessing supply chain risk information began in 2021. Efforts were launched to explore if there is sufficient interest and support and, if so, obtain insight into whether the central library should be a repository or offer more services. These efforts will culminate this spring.

Industry. One activity is being conducted by four trade organizations: APPA, EEI, NATF, and NRECA, to gauge industry interest and support. Great caution is being taken to ensure that an open process is conducted with a focus on enhancing competition, small business participation, diversity, and innovation. The survey was issued to members of the participating trades’ organizations on November 29 and closed on January 18.

Suppliers. A parallel survey activity is being conducted to gauge interest from suppliers and obtain supplier feedback regarding their needs for a central library. This survey was distributed through the International Society of Automation, US Chamber of Commerce, National Electrical Manufacturers Association, NATF, and

NATF members. It is being promoted to electric sector suppliers/vendors and is available to other suppliers that would be interested in responding. This survey was distributed on January 11 and will close on January 24.

These activities will provide insight on whether the development of a central library is a viable solution, based on the level of interest and support from these two groups. The NATF would like to extend our appreciation to the organizations that contributed to the surveys. Future steps in the development a central library will be determined based on the information obtained through these activities.

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Facility Ratings

With strong support and encouragement from the NATF board and member company leadership, NATF members representing approximately 84% of the total transmission mileage at 100 kV and above in the United States and Canada are actively working to enhance their facility ratings practices, processes, and controls. To date, overall member progress has been positive, in aggregate, with increases in both participation and implementation status since the inception of the NATF's facility ratings initiative.

The NATF recently updated its "Facility Ratings Practices Document" to incorporate a risk-based approach for members to use in prioritizing their implementation of certain practices, especially ones that require extensive resources and time to implement. The NATF's risk construct considers (1) categories of facilities based on relative inherent risk to system reliability and (2) scenarios that could increase the likelihood of errors. The update to the practice document also includes some example internal controls for facility ratings processes.

In addition, to provide members with a "one-stop shop" for information related to NATF facility ratings activities, a new page for facility ratings has been created on the NATF's member portal. The new page includes links to existing facility ratings resources, member examples, and a new FAQ section.

Lastly, the NATF is actively engaged in supporting member implementation by highlighting areas of lagging performance, recommending no-regrets actions, and supporting members as needed through targeted assistance.

Ambient-Adjusted Ratings

On a related topic, the NATF is closely monitoring FERC Order 881 ("Managing Transmission Line Ratings") activities and will determine the best ways to support members before, during, and after the three-year implementation period. It is anticipated that best practices related to the order implementation will be developed and socialized throughout the membership to help facilitate effective response.

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Value of NATF Peer Reviews

NATF review teams, comprising the members' own subject-matter experts, conduct periodic, confidential evaluations of NATF member organizations (which we refer to as "hosts"). Each review consists of three to four days of interviews and observations, followed by a report that includes recommendations to the host member's executives and staff. Best practices from both the host and review team organizations are brought back to NATF practice groups for further sharing.

Peer review team members usually bring an equal amount of information back to their own organizations after the review because of the open sharing and discussions between the host and review teams during the interviews. Review team members exchange their own practices and programs with one another and build new peer relationships in the process.

Realized Value

To help understand the overall benefit of the program, NATF staff follows up with hosts at both the six-month and one-year marks to inquire about the status of recommendations offered (i.e., completed, partially completed, planned for future implementation, still under review, or plan to take no action). Recommendations members have completed, partially completed, or plan to complete in the future are considered "realized value," meaning that implementation of the recommendations improves aspects such as member processes, procedures, readiness, safety, and, ultimately, transmission-system reliability and resilience.

Since inception, the NATF membership has provided hosts of peer reviews with approximately 7,900 recommendations and, of those, approximately 5,700 have been acted upon, for a 72% realized value at the one-year mark.

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Redacted Operating Experience Reports

We recently posted three new operating experience reports to the "Documents" section of our public site for members and other utilities to use internally and share with their contractors to help improve safety, reliability, and resilience.

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