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Distributed Energy Resource (DER) Interconnection Improvement Recommendations for the Tennessee Valley

DER Interconnection Improvement Recommendations for the Tennessee Valley

DER Interconnection Standards Pilot

Abstract

Electric utilities throughout North America are facing increasing demand to integrate distributed energy resources (DERs) into the distribution system. To help address this growing challenge, a pilot team composed of staff from the Tennessee Valley Authority (TVA), local power companies (LPCs), and EPRI, have collaboratively developed guidance and tools intended to both enhance and bring greater consistency to DER interconnection practices in the Tennessee Valley. Part of the Regional Grid Transformation (RGT) initiative, this two-year effort has focused on delivering practical insights that more fully recognize DER technology advances, enable procedural transparency and efficiency, and comply with evolving technical standards.

This report briefly describes the RGT Interconnection Standards Pilot project and its objectives, and then presents 80+ recommendations for improving interconnection processes and protocols. These actionable recommendations span administrative, technical review, infrastructural, and standards compliance issues, and adhere to a "capability progression model" that is designed to help LPCs prioritize their strategic planning activities according to the near- and long-term needs of their respective jurisdictions. One of several core Pilot products, the recommendations aim to define workable pathways for progressing the DER interconnection and management capabilities of local power companies serving the Valley. (Additional Pilot outputs include customizable technical interconnection and interoperability requirements [TIIR] for communicating the preconditions of interconnection to DER developers, and sample best practice documentation for better managing grid-connected DER. These documents are available on the Vally Connect website, under "Regional Grid Transformation.")

Acknowledgments

The Tennessee Valley Authority and EPRI would like to thank the following organizations for their committed work to define and pursue the implementation of common DER interconnection standards throughout the Tennessee Valley. Their leadership will help the region build a resilient, flexible and integrated electric system that meets regional customer needs of the future and supports the steady adoption and utilization of distributed energy resources.

- Blue Ride Electric
- Bowling Green Municipal Utilities
- BrightRidge
- Cullman Electric
- Huntsville Utilities
- Jackson Energy Authority
- Knoxville Utilities Board
- Middle Tennessee Electric
- Nashville Electric Service
- Pickwick Electric

- Tennessee Valley Authority
- Tennessee Valley Public Power Association

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Introduction

Rising demand to interconnect distributed energy resources (DERs) – predominately solar photovoltaics (PV), and, to a lesser extent, energy storage and electric vehicles (EVs) – on the distribution system is driving change within the electric utility segment. Specifically, utilities are increasingly exploring opportunities to better manage their DER grid interconnection processes in ways that can more fully leverage technology advances (e.g., advanced inverter functionalities), enable procedural transparency, and recognize evolving technical standards.

In many jurisdictions, these efforts to update utility interconnection procedures are long overdue. An increasing number of utilities are, for example, facing growing connection queues, wide-ranging feeder hosting capacities, and uncertainties in how and when to apply technical screens to address reliability concerns caused by DER grid connections. Meantime, technical requirements, equipment certifications, and standards are also being modified to account for technology changes and emerging grid reliability and safety issues, as well as process-oriented bottlenecks. Most notably, IEEE Std 1547, the de facto standard governing the grid interconnection and interoperability requirements of distributed energy resources in North

America, was updated in April 2018 (referred to as IEEE Std 1547-2018). This new version of the standard is introducing greater technical complexities to account for the various implications of advancing technology and its attendant infrastructure to meet the growing challenges posed by rising penetrations of DERs on the distribution system.

In response to industry changes, the two-year Interconnection Standards Pilot project was launched to help local power companies (LPCs) in the Tennessee Valley explore least-risk, best-value interconnection strategies for meeting changing industry norms and stakeholder expectations. Part of the broader Regional Grid Transformation (RGT) initiative, the pilot is designed to offer LPCs 1) a holistic understanding of the new IEEE 1547-2018, its implications, and contextual approaches for its application; 2) informed recommendations and a timeline for improving current utility DER interconnection practices (that are mindful of IEEE 1547-2018 requirements and needs); and 3) best practices documentation that can be emulated and incorporated into LPC processes, including customizable technical interconnection and interoperability requirements (TIIR) for communicating the preconditions of interconnection to DER developers. Taken together, the pilot's core components seek to provide LPCs and TVA with an integrated understanding of how the utility interconnection process is changing and what utility strategies can be employed to adapt to a shifting energy landscape.

This report summarizes the RGT Interconnection Standards Pilot project and its objectives, and subsequently presents 80+ recommendations for improving LPC interconnection processes and protocols. It is an outgrowth of efforts undertaken by the pilot project team, composed of representative staff from 10 LPCs, the Tennessee Valley Authority (TVA), and EPRI. The actionable recommendations span administrative, technical review, infrastructural, and standards compliance issues, and adhere to a "capability progression model" that is designed to help LPCs prioritize their strategic planning activities according to the near- and long-term needs of their respective jurisdictions. One of several core Pilot products, the recommendations were formulated based on one-on-one meetings and subsequent gap assessments with a sampling of local power companies, as well as broader industry research. Their aim is to define workable pathways for progressing the DER interconnection and management capabilities of local power companies serving the Valley.

Setting the Stage

DER installations are growing at an astonishing rate in many parts of the United States, including areas within the Tennessee Valley. This surge in DER deployment on utility distribution has been accelerating over the last decade and is forecast to continue for the foreseeable future. While new DER adoptions have predominately comprised solar photovoltaics (PV), other technologies are also beginning to gain market traction, including stationary energy storage, collocated solar-plus-storage systems, and electric vehicles (EVs).

The surge in DER deployments is already creating utility interconnection challenges, many of which are expected to be compounded by further grid penetrations of distributed generation systems, technology developments (e.g. advanced inverter functions), as well as regulatory and stakeholder pressure to streamline application review and approval timeframes. Most utilities currently evaluate every proposed distribution-connected project (to varying degrees of rigor), large and small, to ensure that each new generator can be accommodated without causing adverse impacts. This individualized process costs both time and money and represents one of many opportunities for DER interconnection process improvement.

Accelerating the change in utility interconnection procedures is the April 2018 approval of IEEE Std. 1547-2018, the North American standard for interconnection and interoperability of DER with associated electric power systems interfaces.[1] This first full revision of IEEE Std. 1547 since its inaugural approval in 2003 is impelling many utilities to update their interconnection requirements, to adopt parts if not all of IEEE Std. 1547-2018. Indeed, the IEEE 1547 series of standards is often referred to in state legislation explicitly or implicitly, with or without version number and publication date, as the required approach for interconnecting DER to the grid. The upshot is likely to be a flurry of activity to update and revise interconnection standards across the continent.

In isolation, though, IEEE. Std. 1547-2018 does not necessarily require utilities to alter their approach in processing interconnection requests. But its adoption does provide a pivot point for utilities to consider incorporating changes to their interconnection processes and procedures that can encompass both customer-facing and internal improvements. Anticipating the adoption of IEEE Std. 1547-2018 may also catalyze a series of measures utilities can take to better utilize the advanced capabilities of DER technologies. Looking ahead in the near term, DER technologies equipped with autonomous and advanced inverter functions, as well as communications capabilities, are expected to proliferate. Under IEEE Std. 1547-2018, these DER technologies are positioned to evolve from being sources of concern to serving as vital tools for supporting the safe and reliable operation of the utility distribution system (see sidebar).

IEEE Std. 1547-2018: Unlocking the Benefits of Advanced DERs

The recent revision of IEEE Std. 1547-2018, the primary interconnection standard for DER in North America, is the culmination of stakeholder efforts to leverage the grid-supportive capabilities of distributed generation (DG) and energy storage assets. Building on an amendment to the standard instituted in 2014 (IEEE Std. 1547a-2014), which removed restrictions against DER actively participating in grid voltage regulation, the full standard revision of 2018 allows for broader support from both smart inverter and rotating machine functions.

IEEE Std. 1547-2018 specifies the technical and functional *capabilities* for interconnection and interoperability of DER with the grid. It provides details to manufacturers, utilities, and testing laboratories about the performance requirements of new grid-supportive functions, their default settings, and ranges of adjustability. But with a few exceptions, it remains silent on the *utilization* of any of these capabilities and functions. As a result, the new standard offers industry stakeholders, including utilities, a degree of flexibility in implementing 1547-compliant measures to account for differing utility, regulatory, and market contexts.

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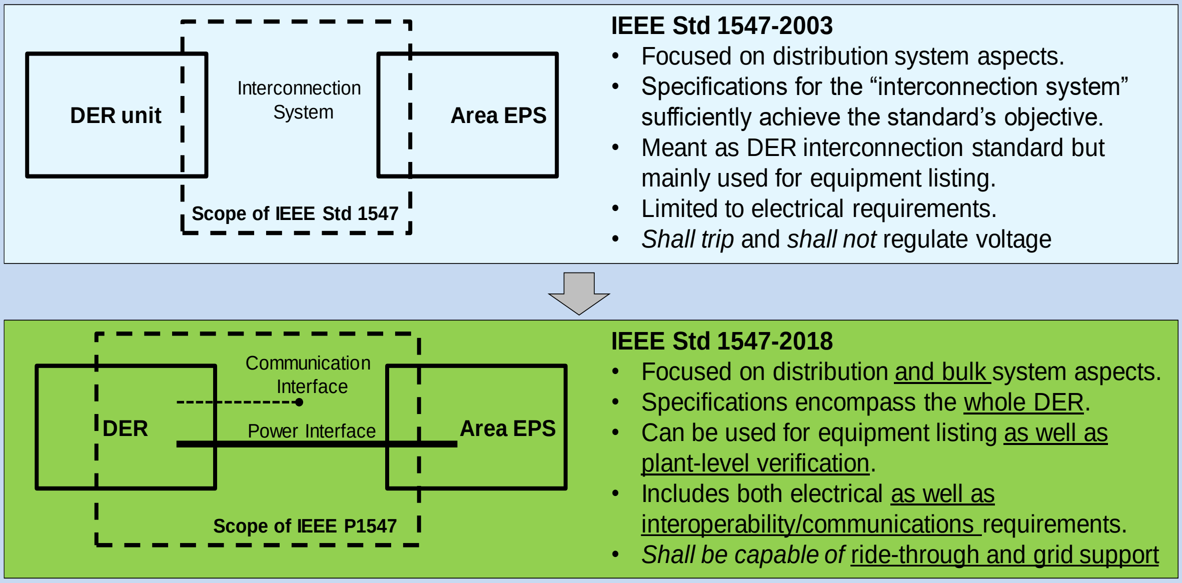
[1] IEEE, "IEEE Std 1547-2018 (Revision of IEEE Std 1547-2003) - IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," https://standards.ieee.org/findstds/standard/1547-2018.html.

Per Figure 1, IEEE Std. 1547-2018 introduces five key elements:

1. Expanded scope that considers distribution system issues as well as bulk system aspects, such as ride-through requirements.
2. Requirements that extend from the interconnection system and the individual DER unit to the whole DER facility (or DER system).
3. Broader application beyond individual equipment listing to plant-level verification.
4. The mandatory development of a standardized and open DER communication interface, as well as the electrical performance of the DER at its electrical connection point.
5. The required capability that DER provide grid support services (e.g. active response to voltage and frequency changes).



IEEE Std 1547-2003

- Focused on distribution system aspects.
- Specifications for the "interconnection system" sufficiently achieve the standard's objective.
- Meant as DER interconnection standard but mainly used for equipment listing.
- Limited to electrical requirements.
- *Shall trip* and *shall not* regulate voltage

IEEE Std 1547-2018

- Focused on distribution and bulk system aspects.
- Specifications encompass the whole DER.
- Can be used for equipment listing as well as plant-level verification.
- Includes both electrical as well as interoperability/communications requirements.
- *Shall be capable of* ride-through and grid support

Figure 1
Changes in the Scope of IEEE 1547, 2003 vs. 2018

Source: EPRI

The adoption of IEEE Std. 1547-2018 is expected to unlock the benefits of advanced DER functions and help utilities meet the evolving needs of the electricity network. It alone will not enable a transition to DER-based support to market and grid operations, but it is anticipated to provide the vital framework for actualizing such a vision. Following are the core activities that will be required to fully realize the potential of distributed energy resources.

- Adoption of standardized DER performance and functional capability requirements detailed in IEEE Std. 1547-2018. The standard grants the utility flexibility to determine the DER capabilities/categories it perceives will offer it the greatest situational benefits.

- Updates to utility interconnection procedures and screenings to match the new advanced DER requirements specified in IEEE Std. 1547-2018. For example, the development of criteria for "fast track" and new supplemental screens is expected to help streamline technical review while recognizing the capabilities of advanced DER functions.

- Implementation of the standard's required communication infrastructure (both networks and architecture) – either by the utility or third-party aggregator – to establish versatile device settings and control modes and, in turn, introduce the necessary flexibility for more fully applying DER in the system.

- Integration of DERs into grid operations and markets to, for example, provide var and frequency support, as well as offset the loss of generation. Clarifying compensation and market rules is viewed as pivotal to furthering the value of DERs as grid resources.

- The pursuit of greater coordination between transmission and distribution planners to help ensure grid reliability as it relates to DER protection, such as voltage and frequency trip functions and related ride-through capabilities.

A significant level of work remains to fully harness the promise of advanced DER functions. But, importantly, IEEE Std. 1547-2018 represents a foundation from which the industry can evolve notional concepts into practical realities.

As LPCs move to adopt IEEE Std. 1547-2018 and update their technical interconnection requirements, they will be challenged on how to utilize these capabilities and functions. But, in response, they will also have the opportunity to improve their internal interconnection processing and review practices in the name of reducing costs, improving customer service, and better meeting customer expectations.

After 10 years of significant DER expansion, there exists a library of best practices for utilities to model their interconnection process improvements upon, starting with the Federal Energy Regulatory Commission's (FERC) Standard Interconnection Agreements & Procedures for Small Generators (SGIP).[2] Additionally, states such as California (Rule 21), Hawaii (14-H), and New York (NY SIR) have revamped their interconnection processes in the recent past, while

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[2] FERC, Standard Interconnection Agreements & Procedures for Small Generators, https://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp.

others, including California,[3] Maryland,[4] Minnesota,[5] and Ohio,[6] are also updating their interconnection procedures and rules. Their goals often coalesce around reducing customer waiting periods, while increasing automation to lessen the burden on utility personnel. Examples of these implemented practices include providing simplified or "fast track" reviews of proposed projects instead of full technical studies, launching online portals, introducing public queues and/or hosting capacity maps, and offering pre-application reports or in-person consultations that characterize project-specific interconnection requirements. More broadly, increased transparency in the utility interconnection process has become a bedrock principal for gaining customer and regulatory trust.

As recognized in IEEE Std. 1547-2018, DERs have driven changes in the electric distribution system over the past two decades—changes that are likely to accelerate in the next decade as more DER adoption occurs and policymakers potentially move to open market access. At the same time, utility practices are continuing to evolve in ways that are intended to handle the anticipated upswings in DER interconnection requests to distribution.

Best Practice Recommendations: Methodological Approach and Scope

EPRI leveraged multiple sources and completed significant data gather and analysis to assess the existing interconnection practices of a representative group of local power companies in the Valley, identify opportunities for their improvement, and based on findings, suggest recommendations relevant to other LPCs in the Tennessee Valley. Information collection was primarily accomplished via In-Depth Interviews (IDIs) with 10 LPCs during the Fall of 2022 (see Table 1 for summary details). These day-long interview sessions were conducted via webinar and involved intensive discussion with LPC personnel responsible for interconnection administration and processing, interconnection technical review, and DER policies and procedures.

Local Power Company	In-Depth Interview Date
Blue Ridge Mountain Electric Membership Corporation	November 15, 2022
Bowling Green Municipal Utilities	November 12, 2022
BrightRidge	November 08, 2022
Cullman Electric Cooperative	November 17, 2022
Huntsville Utilities	November 10, 2022
Jackson Energy Authority	December 02, 2022

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[3] California Public Utilities Commission, "Interconnection Rulemaking 17-07-007," http://www.cpuc.ca.gov/Rule21/.

[4] Maryland Public Service Commission, "Revisions to Comar 20.50.02 and 20.50.09 – Small Generator Facility Interconnection Standards," Administrative Docket RM61, https://www.psc.state.md.us/search-results/.

[5] Minnesota Public Utilities Commission, "Minnesota Statewide Interconnection Standards Update," https://mn.gov/puc/utilities/interconnection/.

[6] Public Utilities Commission of Ohio, "In the Matter of the Commission's Review of Chapter 4901: 1-22 of the Ohio Administrative Code Regarding Interconnection Service," http://dis.puc.state.oh.us/CaseRecord.aspx?CaseNo=18-0884-EL-ORD.

Knoxville Utility Board	December 01, 2022
Middle Tennessee Electric Membership Corporation	November 29, 2022
Nashville Electric Service	December 06, 2022
Pickwick Electric Cooperative	November 08, 2022

Table 1
Summary Details: LPC In-Depth Interviews

The diversity of staff perspectives provided a comprehensive characterization of the current interconnection practices being used in the Valley, as well as future aims. Subject matter areas discussed during the IDIs included:

- Interconnection application management procedures (i.e. current workflow practices and protocols for receiving and processing interconnection applications);
- Technical review approaches (i.e. triggers, screens, and associated costs relevant to different levels of application review based on nameplate or other considerations);
- Existing infrastructure (i.e. staffing and organizational structure, software/hardware platforms and their degree of integration, etc.);
- Energy storage interconnection considerations; and
- Recent/planned interconnection enhancements as well as opportunities for further streamlining and/or automation.

Following the IDIs, extensive follow-up and data cleansing occurred to fill knowledge gaps and address remaining questions. EPRI supplemented knowledge gleaned from the IDIs with survey data collected via a “utility interconnection worksheet.” In addition, secondary sources were referenced, including public-facing LPC interconnection websites and available materials, as well as third-party reports, to attain a more holistic understanding of the interconnection procedures and their contexts.

EPRI subsequently conducted a gap analysis to discern areas for potential improvement and developed an assortment of prioritized interconnection-related recommendations for future consideration. The evaluation focused on the relative degree to which LPC processes could be further streamlined or automated as well as on their level of flexibility to accommodate future requirements. Identified areas for improvement were based on EPRI insights gained through similar utility interconnection practice reviews completed in the recent past. External sources were also consulted that convey interconnection “leading practices” in different states and jurisdictions, discuss areas of unresolved debate, and present an assortment of process improvement possibilities and challenges.

Several IDIs were also conducted with various TVA departments to obtain an informed picture of relevant TVA considerations with regard to DER interconnections made to the distribution system. These discussions helped to, for example, identify current and historical TVA incentive programs targeted at DER on distribution as well as characterize their procedural implications; delimit DER size thresholds and “affected system” concerns that prompt TVA review requirements; and define system reliability requirements as they correspond to IEEE Std. 1547-2018.

Recommendations were subsequently formulated and organized around five themes that espouse overarching utility interconnection objectives. These subject matter themes served as the basis for EPRI's LPC interconnection practices and protocols assessment and were devised based on prior experience as well as industry literature published by The National Regulatory Research Institute (NRRI), National Renewable Energy Laboratory (NREL), The California Public Utilities Commission (CPUC), and various utilities, among others.

Defined in Table 2, the five organizing themes encompass "application management," "technical review approach," "internal infrastructure," and "IEEE Std. 1547-2018-readiness." In the latter theme, five sub-categories were introduced to further segment the embedded recommendations by adoption and utilization topics: Interconnection & Interoperability Capability (adoption); DER Data Management & Functional Settings Determination (adoption); Consideration in Technical Interconnection Review (adoption); Interoperability & Communication Utilization (utilization); and Distribution, Transmission, and Stakeholder Coordination (utilization)

Organizing Themes	Subject Matter Coverage Areas
Application Management	Administrative procedures, tools, online services offered to applicants, customer-facing online elements (e.g., workflow, resourcing, timelines, dispute resolution, queue management, procedural transparency)
Technical Review Issues (General)	Procedures, tools, data surrounding technical review process (e.g., preliminary review, screens, technical / supplemental review, pre-application, timelines, field data validity for hosting capacity analyses)
Technical Issues: Energy Storage	Definitions, tools, procedures surrounding energy storage (e.g., export control, power control systems, inadvertent export, screening techniques)
Internal Infrastructure	The physical architecture / tools / infrastructure that enable interconnection (e.g., GIS into Dx software, tracking software, online portal, tools for stakeholder engagement, staffing)
IEEE 1547-2018 Readiness	Issues specific to IEEE 1547 and its 2018 revision

Table 2
Organizing Themes for Organizing DER Interconnection Recommendations

Capability Progression Model

The RGT initiative has developed a Valley-wide Capability Progression Model (CPM) to help LPCs identify which capabilities are necessary for the grid of the future and self-assess their progress toward each of these capabilities. The CPM is designed for and with LPCs to meet the needs of stakeholders across the region. By outlining capability progression, LPCs are expected to have what they need to make meaningful, measurable advancements that can lead to a sustainable future for their organizations and those they serve.

As part of this effort, a CPM was developed for the DER Interconnection Pilot to align the DER improvement recommendations presented in this report with LPC circumstances, defined by DER interconnection activity, feeder penetration levels, and other metrics. This scheme, shown in Table 3, provides a means for standardizing LPC interconnection capabilities and approaches as DER activity grows in the Valley. It is meant to establish a Valley-wide competency for managing the DER interconnection process by 1) meeting a Valley-wide Standard (assigned to Level 2); and 2) incrementally evolving technical/administrative practices and standards to the appropriate CPM level based on local LPC conditions.

Capability Progression Model: DER Interconnection					
CPM Level Descriptions	**Level 1**	**Level 2** Valley Standard	**Level 3** Valley Transformational Level	**Level 4**	**Level 5**
Defined levels of abilities within each Capability of RGT, ranging from Level 1 (basic/ad-hoc) to Level 5 (world-class). All characteristics listed in a maturity level must be met to be considered achieved.	Basic DER interconnection approach for processing/ technical review; done on an as-needed, ad hoc basis.	Defined and documented manual interconnection admin and technical review processes for DERs on distribution system. *IEEE 1547-2018 Adoption and Implementation (incremental) per RGT DER Interconnection Standards Pilot Recommendations*. **Triggering Need:** Initial applications (>250* kW and <5 MW) for DER interconnection have been received.	Systematic DER interconnection process with study and size-specific guidance, greater transparency based on industry leading practices. Refer to L3 recommendations from *RGT DER Interconnection Standards Pilot*. **Triggering Need:** Recommended for systems encountering >50 apps/year and/or if circuits have >1% DER penetration.	Self-service data-driven DER interconnection process with study and size-specific guidance, greater transparency based on industry leading practices. **Triggering Need:** When and where there is sufficient LPC interest in increasing process efficiencies, improving customer satisfaction and optimizing interconnection queue management.	Largely automated and targeted DER interconnection process with granular interconnection support. Refer to L5 recommendations from *RGT DER Interconnection Standards Pilot*. **Triggering Need:** When and where there is sufficient LPC interest in further increasing process efficiencies, improving customer satisfaction, and optimizing interconnection queue management (e.g., trigger could be an increasing number and volume of interconnection requests, or the need to reduce staff time.)

Table 3
DER Interconnection Capability Progression Model

Per Table 3, the CPM is comprised of five levels, with each level describing increasingly more ambitious DER interconnection-related capabilities that are tied to a range of interconnection improvement recommendations. The Level 1 designation represents a "floor" that all LPCs have met and can work from to advance their processes and practices. Level 1 indicates a jurisdiction with scant DER activity served by an LPC with a basic, manual, and largely ad hoc DER interconnection approach for processing application and conducting technical review. On the other end of the spectrum, Level 5 designation indicates “world-class” interconnection protocols that embrace procedural automation and more targeted, granular DER interconnection processes.

Each level is also affixed to a “triggering need,” which provides the underlying conditions for pursuing the associated recommendations that achieve the level’s goals and mandated reforms. The triggers are tied to application size (e.g., initial applications >250 kW and <5 MW) and volumes (e.g., >50 apps/year), feeder penetrations (e.g., >1% DER penetration), and other LPC objectives, such as increased process efficiencies, improved customer satisfaction, and optimized interconnection queue management.

All LPCs are expected to achieve the Level 2 “Valley Standard” in which interconnection competencies are consistent across the Tennessee Valley. Meanwhile, capabilities enumerated in Levels 3-5 represent transformative goals that are voluntary and can be pursued based on an LPC’s size, customer density, capital and resource availability, or other factors. The CPM provides flexibility for LPCs throughout the Valley to gradually adapt their interconnection practices according to their individual needs and desires.

Opportunities to Improve LPC Interconnection Practices and Procedures in the Tennessee Valley: Best Practice Recommendations

In total, 82 DER interconnection improvement recommendations were devised across the five thematic subject matter areas described above and spanning each of the CPM’s five levels. Per Table 4, the recommendations are further classified by whether they are required to achieve the associated CPM Level or are voluntary goals that would be considered interconnection “leading practices.” Of the 82 recommendations, 29 align with the CPM Level 2 Valley Standard and are required and considered key to ensuring grid safety and reliability. Of these, 24 are tied to adopting and implementing aspects of IEEE Std. 1547-2018, and an additional five are connected to other relevant safety and reliability considerations. The remaining 53 recommendations are not formally required, but they are aligned with North American utility best practices and their adoption provides multiple LPC benefits, including improved procedural efficiencies, reduced labor demand, and cost savings. Their adoption might also be a prerequisite to participation in existing and future DER programs developed by TVA.

Valley-Wide Recommendations Overview

	Level 2 *Valley Standard*			**Level 3** *Valley Transformational*			**Level 4**			**Level 5**			**Recs - Total**		
Theme	**Req’d**	**Goal**	**Total**	**Req’d**	**Goal**	**Total**	**Req’d**	**Goal**	**Total**	**Req’d**	**Goal**	**Total**	**Req’d**	**Goal**	**Total**
Application Management	1	8	9	0	5	5	0	5	5	0	2	2	1	17	18
Tech Review (General)	3	4	7	0	3	3	0	5	5	0	0	0	3	8	11
Tech Issues: Energy Storage	0	5	5	0	5	5	0	3	1	0	1	1	0	14	14
Internal Infrastructure	1	4	5	1	3	4	1	5	5	0	6	6	1*	14	15
IEEE 1547-2018 Readiness	24	0	24	0	0	0	0	0	0	0	0	0	24	0	24
Totals	29	21	50	1	16	17	1	12	16	0	9	9	29	53	82

Table 4
Tally of Valley-wide DER Interconnection Recommendations

*Note: * Facets of same required internal infrastructure recommendation apply to multiple CPM levels.*

The Valley-wide recommendations in abbreviated form are initially listed below, and their long-form descriptions are presented thereafter. Each recommendation has an assigned designation: either “requirement” or “goal” for evolving Tennessee Valley-wide DER interconnection practices. They are furthermore categorized by CPM level to reflect their relative complexity, as well as their capital and labor needs. Note that a timeline for recommendations organized under the “IEEE Std. 1547-2018-readiness” category diverges from that of the other recommendations.

It provides a near-, medium- and long-term timing convention that is focused on the few years for implementations of IEEE Std. 1547.

For ease of review, the abbreviated recommendations shown below are hyperlinked; when clicked on, the reader will be taken to the long-form version of the corresponding recommendation. The long-form recommendation is, meanwhile, also hyperlinked; clicking on the "Back to List of Recommendations" will return the reader to the abbreviated list of recommendations. This arrangement allows the reader to toggle between the short- and long-form recommendations, as desired.

All told, the recommendations presented in this report are intended to help LPCs in the Tennessee Valley improve multiple aspects of their DER interconnection practice, including the associated processes, requirements, standards, and technical reviews that allow for the safe and efficient connection of DER to distribution and help establish and increase hosting capacity for DER while ensuring operational security. The recommendations, which advocate for greater consistency in DER interconnection approaches throughout the Valley, can collectively improve T&D grid reliability and safety, harmonize LPC practices with TVA requirements, and enhance LPC DER application processing and evaluation efficiencies.

Application Management		
#	**Recommendation**	**CPM Level**
1.	Update LPC websites to improve customer service, and provide a self-service option for customers and installers. *(Goal)*	2/5
2.	Provide examples on the LPC's interconnection web page of model single- and three-line diagrams for applicant reference. *(Goal)*	2
3.	Use a standardized interconnection application and interconnection agreement for DER installations. *(Requirement)*	2
4.	Make each LPC's interconnection application a "fillable-PDF" that is available via web download. *(Goal)*	2
5.	Include customers in all written communications with DER installers. *(Goal)*	2
6.	Designate and enforce a non-technical, single point-of-contact to serve as the customer-facing point person. ***(Goal)***	2
7.	Provide publicly-available education/training on interconnection throughout the calendar year and post training sessions online. *(Goal)*	2
8.	Establish and publicize internal timelines for DER interconnection and application processes. *(Goal)*	2
9.	Proactively provide potential applicants with details on the application review process that lay out specific steps that must be completed before PTO can be achieved as well as provide transparency into pricing. *(Goal)*	2
10.	Conduct market research to capture residential customer/installer experiences with LPC interconnection processes. *(Goal)*	3
11.	Publicly state expectations for initial DER plant commissioning and witness testing. *(Goal)*	3

12.	Consider instituting a fee for all interconnection applications submitted and enforcing that applicants reimburse the LPC for the cost of completing more complex technical studies. *(Goal)*	3
13.	Establish and maintain an internal interconnection queue operating under strong “first-in, first-out” principals; provide an online version that can be publicly accessed and monitored. *(Goal)*	3
14.	Adopt a consistent approach for determining whether modifications to an application requires its resubmission and repositioning in the project queue; exclude the addition of DC-coupled energy storage which does not increase a project’s export capacity from the utility’s list of qualifying material modifications. *(Goal)*	4
15.	Determine a process for removing unresponsive projects from the queue after notifying applicants of grounds/timeline for removal. *(Goal)*	4
16.	Allow applicants to securely pay interconnection application fees and/or deposits for technical studies online. *(Goal)*	4
17.	Provide a pre-application report to potential interconnection applicants upon request. *(Goal)*	4
18.	Consider alternative cost allocation methods that can expedite system upgrades needed to accommodate DER interconnections. *(Goal)*	5

Technical Review - General

#	Recommendation	CPM Level
19.	Screen for acceptable transformer ratings that can accommodate the individual and cumulative impacts of small-scale DERs. *(Requirement)*	2
20.	Use the California Energy Commission’s list of qualifying solar panels, inverters, and other DER equipment to expedite review of projects proposed for interconnection. *(Goal)*	2
21.	Require power quality monitors at relatively large DER sites to confirm plant compatibility with the grid and to alert for unexpected power quality issues when grid conditions change. *(Goal)*	2
22.	Develop DER technical review criteria as a public reference for internal and external use. *(Goal)*	3
23.	Develop a [standard] technical interconnection requirements (TIR) document for DER. *(Requirement)*	3
24.	Determine grounding requirements to prevent Ground Fault Overvoltage (GFO). *(Requirement)*	3
25.	Consider reducing the compulsory anti-islanding test for qualified installers using certified UL 1741 inverters for DER installation ≤50 kW (with export capacity limited to 25 kW). *(Goal)*	2/4
26.	Consider requiring DER plant reclosers for 1-2 MW DER systems (include SCADA communications). *(Goal)*	3
27.	Allow DER projects to interconnect to LPC’s network grids and develop standardized technical review processes. *(Goal)*	3
28.	Consider requiring reclose blocking at the main feeder breaker to prevent out of phase reclosing. *(Goal)*	4
29.	Provide guidance on plant recommissioning, including its required elements, triggers, and proposed schedule. *(Goal)*	4

Technical Review – Energy Storage Systems

#	Recommendation	CPM Level

30.	Explicitly define energy storage systems (ESS) as an eligible facility in interconnection rules and update utility interconnection documents – including application forms, study agreements, and interconnection agreements accordingly. *(Goal)*	2
31.	Define and describe the requirements and use of Power Control Systems (PCS), which are essential to capturing the advanced capabilities of storage. *(Goal)*	2
32.	Define and Distinguish Nameplate Rating and Export Capacity in interconnection rules. *(Goal)*	2
33.	Define Operating Profile and Operating Schedule in interconnection rules. *(Goal)*	2
34.	Update interconnection procedures to identify a list of acceptable methods that can be trusted and relied upon to enforce export controls. *(Goal)*	2
35.	Update screening and study processes to specify how limited- and non-export projects are reviewed. *(Goal)*	2
36.	Permit interconnection agreements to allow inadvertent export from "non-export" energy storage systems. *(Goal)*	2
37.	Adopt interconnection screens that distinguish between the Nameplate Rating and the Export Capacity of a project to accurately evaluate the distribution system impacts of export-controlled ESS. *(Goal)*	3
38.	Update interconnection studies to account for the way in which an ESS project's limited export may affect system impact study outcomes. *(Goal)*	3
39.	Consider implementing a new Inadvertent Export Screen into LPCs' review processes. *(Goal)*	3
40.	Adapt screening results so that they provide relevant and useful data that can inform changes to a DER (including ESS) application that enable it to pass a failed screen and avoid the need for grid upgrades. *(Goal)*	3
41.	Provide analysis of alternate options in ESS impact study results. *(Goal)*	4
42.	Improve verification processes to ensure DER/ESS compliance with the terms of the interconnection agreement and streamline associated labor requirements. *(Goal)*	4
43.	Implement a workable approach for assessing ESS with fixed scheduling. *(Goal)*	5

Internal Infrastructure

#	Recommendation	CPM Level
44.	Establish an internal, cross-functional team at each LPC to design, communicate implementation expectations, and monitor end-to-end performance against standardized practices on DER interconnection. *(Goal)*	2
45.	Create internal utility checklists for how interconnection applications are tracked and processed. *(Goal)*	2
46.	Identify and train employees to provide backup/redundancy for each interconnection personnel's function to overcome potential extended absences or bandwidth issues. *(Goal)*	2
47.	Enforce requirement that the sale/transfer of an interconnected DER system be reported to LPCs. *(Goal)*	2
48.	Add details on DER installations (including DER <50 kW) to the LPC's Geographic Information System (GIS), and automate the process. *(Requirement)*	2/4

49.	Develop and institute quality assurance programs on interconnection review processes conducted by LPC engineers.	3
50.	Evaluate effective, low-cost monitoring and control options for mid-sized DER systems (250 kW to 2 MW). *(Goal)*	3
51.	Automate interconnection application status emails, including confirmation of completed application submission. *(Goal)*	3
52.	Track differences between indicative cost estimates (or original customer deposits once instituted) and subsequent detailed cost estimates provided during detailed design and in the final developer invoice; move towards root cause analysis for large and/or consistent deviations. *(Goal)*	4
53.	Create maps detailing distribution system hosting capacity for internal and external use. *(Goal)*	4/5
54.	Launch initiative to clean up inaccurate data in GIS and other data systems in order to enable automation of technical review and use of future DERMS. *(Goal)*	4/5
55.	Replace LPCs' typical use of Excel spreadsheets to manage DER interconnections with a new utility software system to track, integrate documents, and process interconnection requests across the entire lifecycle. *(Goal)*	4/5
56.	Fully integrate back-office systems (e.g., GIS, power flow analysis, etc.) to enable the exchange of data for interconnection review and other processes. *(Goal)*	5
57.	Further develop flexible interconnection agreements to support the greater deployment of grid-connected DER, and pilot a distributed energy resource management system (DERMS) to enable managed control. *(Goal)*	5
58.	Institute integrated distribution planning in the Tennessee Valley. *(Goal)*	5
	IEEE 1547-2018 Readiness ***(Required – Level 2)***	
#	**Recommendation**	**Timing**
Interconnection & Interoperability Capability (IEEE Std. 1547-2018 Adoption)		
59.	Determine the adoption timeline of IEEE Std.1547-2018 (may incl. a stopgap solution for advanced inverters using UL 1741 SA). *(Requirement)*	Near
60.	Assign DER abnormal performance categories. *(Requirement)*	Medium
61.	Assign DER normal performance categories. *(Requirement)*	Medium
62.	Specify a single DER communication protocol, possibly differentiating by DER scale, in conjunction with adopting IEEE Std. 1547-2018. *(Requirement)*	Medium/Long
DER Data Management & Functional Settings Determination (IEEE Std. 1547-2018 Adoption)		
63.	Initiate the collection, management, and maintenance of DER deployment, performance capability, and functional settings data. *(Requirement)*	Near
64.	IF needed, THEN specify preferred settings. *(Requirement)*	Near
65.	IF needed, THEN specify utility-specific settings. *(Requirement)*	Medium
Distribution, Transmission, and Stakeholder Coordination (IEEE Std. 1547-2018 Adoption)		

66. Communicate/coordinate among the multiple Authorities Governing Interconnection Requirements (AGIRs) in the Valley regarding lead times for necessary updates to TIIRs and IA templates, including the need for a stakeholder process. *(Requirement)*	Near
67. Initiate a stakeholder process to determine interconnection and interoperability capability and, IF needed, THEN also preferred functional settings in advance of (or in conjunction with) adopting IEEE Std. 1547-2018. *(Requirement)*	Near
68. Establish protocols/procedures for aggregated data exchange across the T&D interface. *(Requirement)*	Near
69. Initiate development and implementation of internal processes to document and share any non-default DER functional settings (that differ from IEEE Std. 1547 default settings) with DER vendors. *(Requirement)*	Near
70. IF non-preferred, LPC-specific or site-specific settings for trip or any active power related functions are needed, THEN coordinate with TVA, the Regional Reliability Coordinator. *(Requirement)*	Near
71. Initiate stakeholder process to determine future T&D coordination/DER group management functions. *(Requirement)*	Medium
72. Update TIIRs and IA templates with references to IEEE 1547/.1, UL 1741 SB, and communication certification standards, as applicable. *(Requirement)*	Medium/Long
Interoperability & Communication Utilization (IEEE Std. 1547-2018 Utilization)	
73. Ensure that updates to interconnection agreements allow for utilization of the local DER communication interface. *(Requirement)*	Near
74. Interconnection agreements should include specific technical requirements that bar vendor proprietary "lock/unlock" mechanisms from preventing open access to the DER. *(Requirement)*	Near
75. Develop a roadmap to guide DER communication and control system deployment. *(Requirement)*	Medium/Long
76. IF desired, THEN evaluate and establish processes to integrate DERs into grid operations and markets. *(Requirement)*	Medium/Long
77. Select communication networks and federated architecture for DER management (FADER). *(Requirement)*	Long
Consideration in Technical Interconnection Review (IEEE Std. 1547-2018 Utilization)	
78. Consider new IEEE Std. 1547-2018 voltage regulation capabilities early on in technical review criteria (screenings or study); IF desired, THEN develop methods to specify/implement site-specific settings for advanced DER functions. *(Requirement)*	Near/Medium
79. IF technical review (screenings or study) indicates a potential risk of inverter-based DER unintentional islanding AND of inverter onboard anti-islanding detection failure, THEN require and use supplemental means of island avoidance or detection. *(Requirement)*	Medium
80. IF distribution circuit and DER data availability and analytical capabilities allow, move away from existing rules-of-thumb. *(Requirement)*	Medium
81. Develop technical review criteria (screenings or study) for assessing line worker safety during live-line maintenance on feeders with DER enabled for ride-through voltage disturbances (e.g., arc-flash). *(Requirement)*	Medium
82. Consider adopting the IEEE Std. 1547-2018 framework for DER facility design and as-built evaluations, as well as implementing detailed verification procedures beyond those specified in the anticipated IEEE P1547.1. *(Requirement)*	Medium

Recommendations: Application Management

<table>
<tr><th>Recommendation #1
Back to List of Recommendations</th><th>Update LPC websites to improve customer service, and provide a self-service option for customers and installers. (Goal)</th></tr>
<tr><td>Finding/Context</td><td>
<p>In keeping with the goal of serving as its members’ trustworthy partner, LPCs should evolve their website to more fully and accessibly convey the details of DER interconnection. Put simply, their website should be the first place their members go to learn about DER technologies and their grid connection. Awash with publicly-available information about solar PV and other DERs – potentially including misinformation from some installers – an LPC’s website can proactively provide members and installers with objective facts and guidance as a basic customer service.</p>
<p>The utility’s website should be considered a repository for information on the processes and requirements for pursuing grid-connected DER projects of varying sizes and makeup. A comprehensive, well-organized, and feature-rich website can enable greater member self-sufficiency and, in turn, save utility staff time and effort in responding to member and installer inquiries.</p>
<p>Among the leading “bottom line” features that an LPC might consider including in the DER-related area of its website include those listed in the table:</p>
<table>
<tr><th>Website Feature</th><th>Leading Practice Example</th></tr>
<tr><td>Point of Contact name (or generic contact)</td><td>Middle Tennessee's website</td></tr>
<tr><td>Generic contact info (or Point of Contact name)</td><td>Cullman Electric Coop's website</td></tr>
<tr><td>"Call Us" message for more info</td><td>Middle Tennessee's website</td></tr>
<tr><td>Application available for download</td><td>Jackson Energy Authority's website</td></tr>
<tr><td>Interconnection process overview/flow chart*</td><td>LADWP’s Type 1 Interconnection Process; National Grid’s Interconnection Process; PG&E’s interconnection resource page; MN DIP Integration Workflow; National Grid (MA) Road Map</td></tr>
<tr><td>Sample SLDs (string and micro-inverter configurations) for download</td><td>Manitoba Hydro website</td></tr>
</table>
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</table>

Interconnection Agreement for download	BGMU Interconnection Customer Agreement
Technical Interconnection Requirements (TIR)	BGMU Distributor Interconnection Procedures
Technical information for installers	Consolidated Edison information for Installers
Fees associated with DER installations	BRMEMC FAQ dropdown
Battery storage reference	BrightRidge's website
Battery storage-specific information	Sacramento Municipal Utility District website

** Many utilities have developed flow charts depicting their interconnection processes that they will share with customers/installers upon request.*

Frequently asked questions (or FAQs) are a useful tool to provide answers to commonly repeated questions from members or installers. They can also be used to provide information on key items that an LPC believes would benefit its members.

The table lists a series of recommended FAQs to include on an LPC's website. However, additional FAQs could be added to further educate prospective applicants about the merits and logistics of pursuing solar and other DER projects. Note how the listed FAQs are generally in line with how homeowners and businesses think through both the merits and logistics of pursuing a DER project.

FAQs to Include	Leading Practice Example
Is my roof right for solar power?	Consolidated Edison DER FAQs
How much electricity will my rooftop PV system produce?	Consolidated Edison DER FAQs
Will my system work at night or in winter?	Consolidated Edison DER FAQs
Will my solar panels work during an outage?	Consolidated Edison DER FAQs
How much will my LPC or TVA pay for power exported to the grid?	Consolidated Edison DER FAQs
Will my system require maintenance?	Middle Tennessee Electric Solar FAQs
How long will my system last?	BRMEMC FAQs
I got solar panels so I wouldn't have to pay anymore LPC bills? Why are you still charging me?	Consolidated Edison DER FAQs
How to select an installer	Consolidated Edison DER FAQs
What is community solar?	PEPCO Community Solar FAQs

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<table>
<tr><td>FAQs for battery energy storage</td><td>Sacramento Municipal Utility District</td></tr>
</table>

An additional FAQ that LPCs may consider is to emphasize the need for an inspection of the installed DER system by the local authority having jurisdiction (AHJ), and to include contact information for those AHJs that conduct inspections in an LPC’s service area.

Finally, per the following table, there are some optional features that an LPC can consider adding to its website. The examples listed tend to provide a greater level of information on issues beyond those tied to primary interconnection requirements.

<table>
<tr><th>Website Feature to Consider</th><th>Example</th></tr>
<tr><td>General "Understanding Solar Energy" overview</td><td>Consolidated Edison</td></tr>
<tr><td>Assessment of PV economics</td><td>PG&E website (powered by WattPlan)</td></tr>
<tr><td>Solar Calculator (TVA example), NREL’s PVWatts*, and/or Google Project Sunroof</td><td>BrightRidge's website; Knoxville Utility Board's "Generate Your Own Power" website; Riverside Public Utilities website</td></tr>
<tr><td>Solar Power for your Home: A Consumer's Guidebook*</td><td>Louisiana State University Guidebook</td></tr>
<tr><td>Link to training videos</td><td>Middle Tennessee's main solar webpage</td></tr>
<tr><td>TVA Virtual Solar Education Tour link</td><td>Knoxville Utility Board's "Generate Your Own Power" website</td></tr>
<tr><td>Green Connect link</td><td>Huntsville Utilities’ website</td></tr>
<tr><td>Preferred or registered DER installer list</td><td>CPS Energy registered installer list and Salt River Project preferred installers</td></tr>
<tr><td>Information on available Federal incentives for DERs</td><td>Middle Tennessee's FAQ webpage</td></tr>
<tr><td>Hosting capacity map(s)</td><td>Ameren Illinois</td></tr>
</table>

** The LSU guidebook is in the public domain and can be used with no fee.*

An LPC would not necessarily include all of these optional features on its website in the near-term; for example, posting hosting capacity maps are unlikely to be useful until DER penetrations begin to exceed double-digits of feeder capacity. However, most of the listed items would be useful to an LPC’s members and active installers in the near-term.
</td>
</tr>
<tr><td>Benefits</td><td>Enhanced Customer Experience; Improved Internal Efficiencies</td></tr>
<tr><td>Implementation Outlook</td><td>Progression Model Level 2-5 (Most website features are Level 2 and 3 activities, with hosting capacity maps and some other more functionally rich features are Level 4 and 5 activities)</td></tr>
</table>

Recommendation #2 Back to List of Recommendations	**Provide examples on the LPC's interconnection web page of model single- and three-line diagrams for applicant reference.** ***(Goal)***
Finding/Context	Most LPCs require that interconnection applicants provide a diagram in their submitted application package. As reported by numerous North American utilities, diagrams are often submitted incorrectly, holding up an application from being formally accepted and entered into technical review. Easy-to-access model diagrams can educate applicants/developers on both what these line diagrams should include and how they should be drawn. LPCs typically do not provide detailed diagrams, which they could do so as is done by Manitoba Hydro. Clearly providing reference to these model diagrams could, in turn, potentially reduce delays caused by LPC requests for more or correct information from applicants, while reducing LPC workstreams.
Benefits	Improved Internal Efficiencies, Enhanced Customer Experience
Implementation Outlook	Progression Model Level 2

Recommendation #3 Back to List of Recommendations	**Use a standardized interconnection application and interconnection agreement for DER installations.** ***(Required)***
Finding/Context	Many LPCs use their own DER interconnection application and interconnection agreement (IA). Consequently, some LPCs do not have a formal application, while others do not require DER projects under 1 MW to sign an IA. The inconsistent application approach by LPCs in the Valley has the potential to leave out important information that the utility should acquire and store (including in its GIS). Although this might not seem necessary at current DER penetration levels on many LPCs' systems, it could be increasingly important to safely operating and planning the utility's distribution system as DER proliferates. Meanwhile, an IA establishes the legal responsibilities for both DER owner and LPC, which are important to stipulate. LPCs should require that all DER projects submit an application with details on the DER technology type(s) to be deployed, system capacity, and inverter details (including whether listed under UL 1741); for energy storage projects, details should include whether they will be DC- or AC-coupled, their mode of operation, and (if relevant) the type of export control used. Per Recommendation #1, the application should be

	available for download on each LPC's website. Likewise, LPCs should consider requiring all DER projects sign an IA, which also can be posted to the LPC's website. As the regulator, TVA could, meanwhile, consider requiring that LPCs use a Valley-wide application that includes the minimum recommended information to be collected for proposed DER projects. For larger DER systems, additional technical details on the DER system and its electrical characteristics would be needed, as well as prospective information on IEEE 1547-2018-related criteria. The TVA Application for Interconnection used in TVA's Green Connect program is recommended as the starting point for such a Valley-wide template, while the IA used for TVA's Green Connect program is recommended to be used by all LPCs as the Valley-wide template. LPCs could be allowed to modify the IA (as well as the interconnection application), based on their specific needs. Regardless, establishing a minimum requirement for the information collected via the DER interconnection application and contractual language included in the Interconnection Agreement should be a priority for all LPCs to adopt.
Benefits	Readiness for Future System Evolution; Consistency and Quality
Implementation Outlook	Progression Model Level 2

Recommendation #4 Back to List of Recommendations	**Make each LPC's interconnection application a "fillable-PDF" that is available via web download.** ***(Goal)***
Finding/Context	Many, though not all, LPCs post a PDF of their interconnection application on their respective websites. Often, however, this PDF file must be printed, filled out by hand, and either emailed or snail mailed by the applicant to the LPC along with additional required materials. To reduce errors related to penmanship, a "fillable-PDF" formatted file can be supplied to customers for completing the application. This document can be downloaded and completed on a computer or tablet, thus enabling applicants to more quickly and accurately complete the form, while also lessening the time spent by LPC staff to translate the entries. A fillable-PDF can also reduce the likelihood of errors being manually input by utility personnel into an LPC's interconnection tracking system. The applications should also permit the use of an electronic signature by the customer.
Benefits	Improve Customer Experience; Improve Internal Efficiencies

Implementation Outlook	Progression Model Level 2

Recommendation #5 Back to List of Recommendations	**Include customers in all written communications with DER installers.** ***(Goal)***
Finding/Context	Some LPCs report that if a DER interconnection application is submitted by an installer (instead of the LPC customer), they do not always include the customer on future written communications. These LPCs could consider including their customers on all written communications with the DER installer as a practice to increase project transparency and ensure that their customers receive direct information from the utility (instead of second-hand from the installer). This modified process would ensure that the customer is receiving complete and accurate information as to the LPC's requirements and potential obstacles facing a project. It would also help prevent the installer from placing blame on the LPC for activities the installer might be responsible for (e.g., scheduling and successfully completing an onsite electrical inspection from the authority having jurisdiction [AHJ]).
Benefits	Enhanced Customer Experience
Implementation Outlook	Progression Model Level 2

Recommendation #6 Back to List of Recommendations	**Designate and enforce a non-technical, single point-of-contact to serve as the customer-facing point person.** ***(Goal)***
Finding/Context	Many LPCs currently rely on word-of-mouth for customers and installers to determine who to call and how to apply for permission to connect a new DER installation to the utility's system. To enhance customer service and internal LPC efficiencies, however, it would be useful to assign a single point-of-contact (POC) at an LPC who is both responsive to members and educated about the interconnection process. This person would preferably be listed on the LPC's website as well as on collateral (including the DER interconnection application) as the person to contact with questions about the interconnection process and application status. At most utilities outside the Tennessee Valley, the point of contact is in the Customer (or Member) Services department, and not part of the engineering team.

	An appointed single POC (in the Member Services department or otherwise) would be responsible for the day-to-day tracking of interconnection applications (including managing the internal workflow), fielding non-technical and rote technical inquiries, as well as communicating application approval (or rejection). This set up would allow much of the administrative work, as well as most of the interconnection-related inquiries, to be resolved by a non-technical staffer. In turn, the activities undertaken by technical staff could be more focused on higher-level activities, including DER application technical review (along with other technical responsibilities).
Benefits	Enhanced Customer Experience; Improved Internal Efficiencies
Implementation Outlook	Progression Model Level 2

Recommendation #7 Back to List of Recommendations	**Provide publicly-available education/training on interconnection throughout the calendar year and post training sessions online.** *(Goal)*
Finding/Context	Proactively educating potential customers/developers and other government officials (e.g., AHJs for codes) through face-to-face training sessions and workshops, webinar presentations, and associated written materials on a range of informational topic areas relevant to the interconnection process can increase general fluency as well as the quality of submitted applications. In the past, some LPCs have hosted engagement sessions with installers or AHJs, though these sessions have not been convened for nearly three years given the COVID-19 pandemic. The key to successful education is identifying high priority customer/developer training needs that will have the greatest positive impact on improving the interconnection process experience for all parties involved. For example, LPCs may find it useful to educate DER interconnection applicants about the basics of the interconnection submission and review process; this could be a topic for a webinar. Xcel Energy and Consolidated Edison have produced useful DER interconnection training materials that LPCs may consider leveraging for their own resources. Hosting working group meetings with developers can also serve as a forum for discussing issues and challenges that are impeding the interconnection process—whether it be for conventional interconnection issues, or newer ones that might include solar-plus-storage. Recording these sessions and posting them to an LPC's website would allow developers (workshop attendees and otherwise)

	to stay up-to-date on evolving interconnection processes and requirements. Middle Tennessee EMC offers one example of a utility's effort to post interconnection-related training videos. Austin Energy's Solar Education Course is another best practice example of utility packaged information explaining the ins and outs of solar and its installation. Finally, LPCs may consider conducting internal trainings with their staffs and external consultants (if applicable) to address identified interconnection-related challenges and procedural improvements. Example internal trainings might include stepwise approaches to conducting on-site commissioning, efficient review of residential and small commercial application quality checks, among other topics. Overall, utility availability and transparency can improve customer/developer relations in addition to the actual interconnection process.
Benefits	Enhanced Customer Experience
Implementation Outlook	Progression Model Level 2

Recommendation #8 Back to List of Recommendations	**Establish and publicize internal timelines for DER interconnection and application processes.** *(Goal)*
Finding/Context	LPCs do not appear to typically publish timelines for reviewing DER interconnection applications. As a result, applicants have no guidance on how long it might take for an LPC to complete its analyses and provide a project approval (potentially per specified conditions). This uncertainty could prove detrimental in a variety of ways: it could impact the ability of project developers to plan for other permitting activities, determine construction timing, and even line-up financing. Such timelines could also temper customer expectations on the speed with which their project might be completed. A standard utility interconnection best practice includes the establishment of specific timeframes by which utilities must respond to DER applications, with each step in the process having its own requirement. The FERC's Small Generator Interconnection Procedures (SGIP) includes such timelines. LPCs could consider adopting internal timelines for the interconnection review process, to be shared by the LPC with its customers and installers—either as part of its correspondence with applicants and/or on its public-facing website.

Benefits	Enhanced Customer Experience, Consistency & Quality
Implementation Outlook	Progression Model Level 2

Recommendation #9 Back to List of Recommendations	**Proactively provide potential applicants with details on the application review process that lay out specific steps that must be completed before PTO can be achieved as well as provide transparency into pricing.** ***(Goal)***
Finding/Context	For most utility customers, the process of requesting and obtaining approval to install a DER is unclear. Likewise, given utility and jurisdictional differences, installers are often confused about what is required of them. Providing a short, yet clear checklist of the steps involved in the interconnection process – and what is required of the customer and installer – provides improved knowledge and transparency to all involved parties, making it easier to successfully undertake the process, as well as reduce the volume of informational requests from LPCs. Furthermore, providing a clear rendering of an LPC's interconnection review process on the utility's website and via PDF handouts offers potential interconnection applicants an opportunity to learn what the study process entails and the range of associated costs—even before an initial application is submitted. LPCs could benefit by clearly differentiating how interconnection applications are reviewed, and, in turn, influence customer expectations before an actual application is submitted. Middle Tennessee Electric (MTE) sends its members a "welcome to solar" checklist listing its interconnection process (including prospective timelines) once it receives a new DER interconnection application. Knoxville Utility Board (KUB), meanwhile, has drafted a one-page checklist and cost information that, once finalized, it plans to post to its website for customers and local installers to download and use. KUB's aim is to support transparency, better information dissemination, and higher quality applications for its interconnection process. Other utility examples outside the Tennessee Valley include Sacramento Municipal Utility District, AEP Ohio, Southern California Edison, National Grid, and Exelon's Atlantic Energy). LPCs could consider adopting similar information, including a checklist that clearly states what is required of its members (and their installers), the process that an LPC takes in reviewing and approving or rejecting an application, and the associated fees.

Benefits	Enhanced Customer Experience; Consistency & Quality
Implementation Outlook	Progression Model Level 2

Recommendation #10 Back to List of Recommendations	**Conduct market research to capture residential customer and installer experiences with LPCs' interconnection processes.** *(Goal)*
Finding/Context	LPCs are likely to move toward refining their interconnection practices and procedures over the next few years. Before committing to selected future actions, market research efforts can help LPC staff learn from DER interconnection customers and developers/contractors about their experiences with the current process as well as their associated likes and dislikes. Likewise, an LPC could specifically focus its post-interconnection research efforts on specific technologies such as energy storage. Incorporating the voice of the customer/contractor into LPCs' consideration of future changes to the utility's interconnection processes (and embedded platforms) can provide invaluable and unique insights into what works well and what could be improved in an LPC's interconnection approach. Options for soliciting customer/installer feedback and perspectives include issuing surveys – one soon after Permission to Operate (PTO) is granted, another one year later; periodically convening focus groups; and including "feedback sessions" as part of LPC-run interconnection training workshops/modules (see Recommendation #7).
Benefits	Enhanced Customer Experience, Consistency & Quality
Implementation Outlook	Progression Model Level 3

Recommendation #11 Back to List of Recommendations	**Publicly state expectations for initial DER plant commissioning and witness testing.** *(Goal)*
Finding/Context	Most LPCs provide little or no guidance to DER developers and owners regarding commissioning and witness testing requirements. Providing a list of commissioning requirements would offer greater certainty that the commissioning tests performed by the asset owner's representatives, vendors, and other third parties are appropriate to ascertain compliance with the

	interconnection agreement, IEEE Std. 1547-2018 (if it is adopted), and other relevant standards. The commissioning tests required will differ based on DER system parameters, including size and complexity, the type testing performed, and any unique aspects of the interconnection. Meanwhile, the witness tests required will include those based on the results derived from required commissioning tests. Witness testing is the final opportunity before final acceptance of the system; it is undertaken to help assure a high probability of reliable DER system operation and grid interconnection. Clarification of plant commissioning and witness testing requirements would decrease the probability of issues arising that can be time consuming to resolve; in some cases, it may also help LPCs avoid making incorrect conclusions during testing. LPCs (potentially in collaboration with TVA) should consider developing training materials and events to help educate stakeholders about its expectations surrounding witness and commissioning practices. These efforts could help stress the importance of the commissioning tests and certification to the asset owner.
Benefits	Enhanced Customer Experience; Improved Internal Efficiencies; Consistency & Quality; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 3

Recommendation #12 Back to List of Recommendations	**Consider instituting a fee for all interconnection applications submitted and enforcing that applicants reimburse the LPC for the cost of completing more complex technical studies.** ***(Goal)***
Finding/Context	A number of LPCs do not charge an interconnection application fee for residential-scale DER system. Likewise, not all LPCs clearly document that they will charge engineering study fees for larger systems. To reduce potential cross-subsidy among its customers and move toward an interconnection approach that aims to recover the full costs from customer-induced interconnection activities, LPCs could consider adopting a standard, one-time fee for all interconnection applications that are based on capacity tiers (and not on customer segment).

	Additionally, LPCs could clearly state that they could charge customers for the labor of engineering staff conducting technical reviews of larger systems. As a courtesy to customers, LPCs could also consider only charging for technical reviews that go beyond a certain level of effort; Pepco Holdings, Inc. (PHI), for example, only assesses charges to technical studies that require more than 10 hours of utility labor. Charging customers an application fee is a widely accepted practice. For example, FERC’s SGIP suggests a $100 fee for projects with capacities of 10 kW or less. Many states require an application fee be imposed by its regulated utilities. For example, Washington State’s WAC Chapter 480-108 includes a $100 application fee for DER projects up to 25 kW. Minnesota’s interconnection standard (State of Minnesota Distributed Energy Resources Interconnection Process - MN DIP) require a $100 plus $1/kW of DER capacity fee for certified larger scale systems. LPCs could also contemplate providing DER owners with a rebate for such application fees if they ever participate in an LPC-sponsored program to use their member-owned DERs (e.g., bring your own device program, scheduled dispatch program, etc.).
Benefits	Consistency & Quality; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 3

Recommendation #13 Back to List of Recommendations	**Establish and maintain an internal interconnection queue operating under strong “first-in, first-out” principals; provide an online version that can be publicly accessed and monitored.** ***(Goal)***
Finding/Context	A best practice among North American utilities is maintenance of a queue of projects that are applying for interconnection. This typically involves accurately completed applications being assigned queue positions based on their date- and time-stamp (typically recorded every one-second), and that their processing follow a strict “first-in, first-out” principal for queue management (in order to be non-discriminatory). Other sequential queue management rules clearly define procedural timelines for both utility and applicant, including terms for queue removal, among other issues. These measures ensure

	accountability by both the utility and applicants, as well as transparency to all stakeholders. Few LPCs currently employ a queue management process that includes the first-in, first-out approach. That is largely due to the relatively low level of DER interconnection applications, particularly for projects above 25 kW that might take longer to conduct a technical review on. Applications are typically assessed and reviewed based on their readiness. Even though individual LPCs have yet to encounter feeder hosting capacity constraints that can affect the interconnection of new DER additions, it is recommended that a strong first-in, first-out review process be implemented *before* such situations arise. Related, a growing number of U.S. jurisdictions – including New York's Standardized Interconnection Requirements (NY SIR), California's Rule 21, and Minnesota's DER Interconnection Process (MN DIP) – require that a public queue be provided online and updated regularly (typically monthly) to inform individual applicants about the status of their requests, including visibility into projects that are in front of them in the queue. LPCs could consider providing more visibility on their future interconnection queues as part of a broader initiative to make their interconnection processes more transparent and promote greater customer self-sufficiency. (A more involved component of this broad-scale effort is the introduction of hosting capacity maps, per Recommendation #53.)
Benefits	Enhanced Customer Experience; Improved Internal Efficiencies
Implementation Outlook	Progression Model Level 3

Recommendation #14 Back to List of Recommendations	**Adopt a consistent approach for determining whether modifications to an application requires its resubmission and repositioning in the project queue; exclude the addition of DC-coupled energy storage which does not increase a project's export capacity from the utility's list of qualifying material modifications.** ***(Goal)***
Finding/Context	Once an LPC establishes an interconnection queue on a first-come-first-serve basis (see Recommendation #13), it next needs to determine its practices for how to handle changes to a DER project once an application has been accepted and deemed complete. Such modifications might include, for example, a project's inverter model being

	modified, or energy storage being added to an existing project's design. LPCs (in collaboration with TVA) should consider adopting and publicizing a clear and consistent approach for determining whether a project modification is material (or not). Communicating such an approach with project applicants can ensure they are aware of the implications of a potential project change for queue positioning. Moreover, publicizing its approach would allow an LPC to reduce judgements being made by utility personnel, while providing transparency to the DER developer community. LPCs should also consider excluding the addition of a DC-coupled energy storage system from its list of qualifying material modifications if such a system does not increase the project's export capacity. Utilities such as Duke Energy Carolinas are, in fact, promoting the adoption of DC-coupled solar-plus-storage as a means to avoid material changes to solar projects planning to add storage once they are in the interconnection queue. Although it does not appear that any LPC currently faces any challenges regarding material modifications and their consequences for queue positioning, it is recommended that they develop an approach in the medium-term that provides clarity on how the utility will address potential queue issues that may arise in the future with increased interconnection activity.
Benefits	Enhanced Customer Experience; Consistency & Quality
Implementation Outlook	Progression Model Level 4

Recommendation #15 Back to List of Recommendations	**Determine a process for removing unresponsive projects from the queue after notifying applicants of their projects' grounds and timeline for removal.** ***(Goal)***
Finding/Context	Once an interconnection queue has been established, it is important to include an equitable process for removing projects that are no longer being actively pursued. Such projects, by being in the queue, can take hosting capacity away from active projects. LPCs could adopt a practice of alerting customers/developers of a project's scheduled removal from the interconnection queue.

	This in mind, it is recommended that project applicants who have not been responsive to utility requests for further information, or have interconnection agreements (IAs) that have not moved forward, should be removed after the timeframe of three years passes (per Maryland's policy). To identify stalled projects more easily, an LPC could activate a flag in its interconnection queue to produce a list of projects that have not, for example, progressed for over 12 months. Jurisdictions have taken different approaches for notifying applicants of queue removal. The New York SIR, for example, does not stipulate that utilities are required to alert interconnection applicants that their project will be removed from the queue due to missed deadline or unresponsiveness. Other jurisdictions, notably California's Rule 21, do require such utility notification. Under Rule 21, California's utilities provide applicants with five (5) business days' notification to act to prevent losing their queue position. The short amount of time is fair to other applicants in the queue, whose projects are potentially being held up by the stalled project. It is recommended that LPCs consider making a good faith attempt to contact the developer, particularly given delays project developers have faced in securing final permits.
Benefits	Enhanced Customer Experience
Implementation Outlook	Progression Model Level 4

Recommendation #16 Back to List of Recommendations	**Allow applicants to securely pay interconnection application fees and/or deposits for technical studies online.** ***(Goal)***
Finding/Context	Interconnection applicants are required to pay application and study fees to most LPCs via a bank check that must be delivered (typically via USPS mail or hand delivered) to the utility. But first, the LPC might need to have an invoice issued to bill the installer, and once paid, manually communicate from the Billing Department to the internal person responsible for tracking applications that the check has been received. Online payment can provide greater convenience to applicants as well as reduce utility processing time and potentially credit card fees. Currently, LPCs typically have to match up individual checks with specific projects, which can be time-consuming. Electronic payment processing can also be automated, reducing the potential for clerical errors made by utility staff and labor requirements for handling, recording, and processing project-specific check payments. Other utilities

	– including National Grid, Salt River Project, and Eversource Energy – have implemented ACH funds and even credit card payments through portals (e.g., Clean Power Research's PowerClerk); building on their experience should ease the adoption of electronic payment. Caveat: online payment may require modifications to an LPC's other back-office procedures.
Benefits	Enhanced Customer Experience; Improved Internal Efficiencies
Implementation Outlook	Progression Model Level 4

Recommendation #17 **Back to List of Recommendations**	**Provide a pre-application report to potential interconnection applicants upon request.** ***(Goal)***

Finding/Context	Upon request, LPCs may consider providing prospective applicants with a pre-application report for a planned project. A pre-application report serves as a means for applicants to, for a modest fee, determine the economic merits of pursuing interconnection before actually submitting a full application. The utility identifies the substation/bus/circuit likely to serve the proposed DER installation and provides the applicant with known information about the existing feeder (e.g., nominal voltages, peak and minimum loads, queued generation on that feeder, etc.). The pre-application report can help applicants target their projects at circuits where greater hosting capacity is available and fewer potential issues may arise, thus reducing the need to conduct full studies on projects that may potentially require costly system upgrades to accommodate them. Some LPCs currently encourage prospective DER interconnection applicants to contact the utility to discuss their project(s). Even though the volume of DER interconnection applications received by most LPCs appears insufficient for instituting pre-application reports in 2023, planning for their adoption in future years would prepare the utility for potential growth in applications. The pre-application report is part of FERC's SGIP and is considered a "best practice" (suggested price point: $300/report). An example pre-application form from Commonwealth Edison can be accessed here. Caveat: if demand for pre-application reports is anticipated to be minimal, then an informal pre-application consulting option may be sufficient.
Benefits	Enhanced Customer Experience; Improved Internal Efficiencies
Implementation Outlook	Progression Model Level 4

Recommendation #18 Back to List of Recommendations	**Consider alternative cost allocation methods that can expedite system upgrades needed to accommodate DER interconnections.** ***(Goal)***
Finding/Context	Most LPCs appear to follow the standard practice of requiring that individual DER applicants pay for the entirety of utility-side investments needed to safely interconnect their projects. This "cost causer pays" approach has long been used by utilities to allocate system upgrades needed to support additional DER. It follows the principle of cost

	causation and is simple in its execution (which can keep transaction costs low). However, the status quo approach can also undermine DER project economics given that system upgrade costs are imposed on a singular project; free-rider problems can, meanwhile, occur as subsequent customers applying for interconnection on an upgraded feeder benefit without paying for the upgrade costs. In the future, as an LPC's distribution system starts having locations that approach their hosting capacity limits, cost allocation could become increasingly relevant. The added cost to a single DER project to fund a substation upgrade is likely to be prohibitive unless the project has a particularly large capacity. As a result, the circuits fed by constrained substations within LPCs' service areas could potentially be closed off to future DER interconnections. Revising an LPC's cost allocation approach could resolve potential bottlenecks, and there are several directions an LPC could go in (see EPRI report, *Exploring DER Interconnection Cost Allocation Approaches and Tradeoffs* [3002012961]). It could, for example, petition TVA to pay for such upgrades itself, thereby justifying the inclusion of the investment into its rate base as being a benefit to the overall system. It could alternatively pursue group (or cluster) studies, which spread the cost of utility system upgrades among a group of DER projects hoping to interconnect in an affected area. Such cluster studies, such as those pioneered in California and used by Duke Energy, among other utilities, enable costs to be recovered proportionally to each project's relative need for the upgrade, but can cause increased expense if projects drop out (thus requiring a group study redo). Alternatively, New York utilities have experimented with post-upgrade allocation methods, in which upfront mitigation costs are paid for by either the initial cost causer or by the utility, and subsequently reimbursed by future projects that interconnect to the upgraded circuit. A major challenge, however, is that these approaches tend to place risk on the original project owner or utility distribution customers given the uncertainty of whether future projects will materialize. Although cost allocation is ultimately a regulatory issue, exploring and/or advocating for alternative cost allocation

	methods can help support the greater deployment of grid-connected DER, promote potentially more equitable methods for funding system upgrades, and enhance customer relations.
Benefits	Enhanced Customer Experience; Consistency & Quality
Implementation Outlook	Progression Model Level 5

Recommendations: Technical Review Issues – General

Recommendation #19 Back to List of Recommendations	**Screen for acceptable transformer ratings that can accommodate the individual and cumulative impacts of small-scale DERs.** ***(Requirement)***
Finding/Context	LPCs currently review small-scale DER applications, including their associated single-line diagrams (SLDs), for their completeness and accuracy. However, as part of this effort, many LPCs *do not* check whether nearby service transformers have an acceptable rating to handle the potential injection of power from new connections, and/or the cumulative grid exports of existing small DERs. Conducting this screen, as stipulated in the Small Generation Interconnection Procedures (SGIP, for example, 2.2.1.7 and 2.2.1.8), can prevent future overloading of utility equipment on the circuit and is standard practice for utilities when reviewing small-scale DER interconnection applications. Given that small-scale DER installations tend to cluster in neighborhoods, LPCs should be required to add this screen to its current review process before issues appear with overloaded transformers, and before a full revamping of their interconnection processes is needed. Some LPCs report that they have already experienced residential DER activity that has exceeded service transformer capacity, highlighting the importance of conducting this simple check. If an LPC is including DERs and their respective service transformers in its GIS (see Recommendation #48), this technical screen could potentially be automated in the future.
Benefits	Streamline Technical Review
Implementation Outlook	Progression Model Level 2

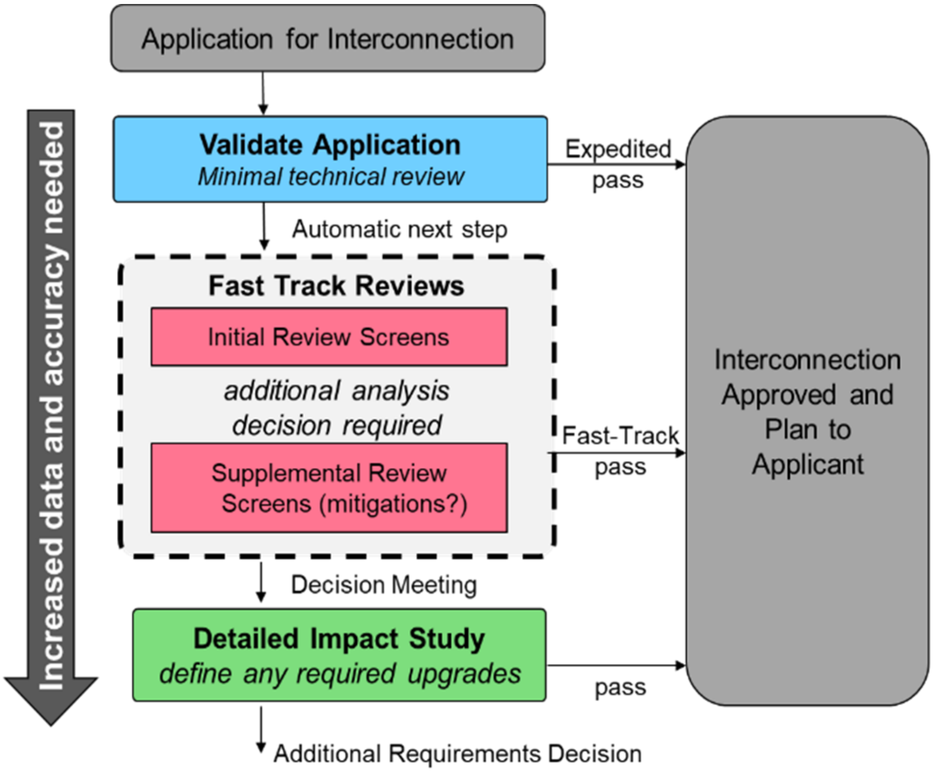
Recommendation #20 Back to List of Recommendations	**Use the California Energy Commission's list of qualifying solar panels, inverters, and other DER equipment to expedite review of projects proposed for interconnection.** ***(Goal)***

Finding/Context	Many LPCs currently require DER interconnection applicants to submit specification sheets for PV panels and inverters they propose to utilize in their prospective projects. This information is reviewed by LPCs to ensure that listed and application-appropriate equipment are used in projects. Such an activity could become time-consuming as application volumes rise, particularly if unfamiliar equipment is proposed for use. Instead of conducting a primary review of every project's equipment specification sheets, LPCs could consider confirming that the panels, inverters, and other equipment specified for a project are included in the California Energy Commission's (CEC) equipment lists during the project application's technical review. Equipment on the CEC's list – covering PV modules, inverters, energy storage systems, batteries, meters, and power control systems – meets established national safety and performance standards. For equipment that is not included in the CEC's approved lists, an LPC could request specification sheets and determine whether it is acceptable for system connection. Outsourcing confirmation that a product is compliant with the CEC's relatively tough equipment requirements should provide peace of mind that a plant is safe for an LPC's system. It can also ensure that future DER projects are using UL 1741-listed inverters, which would ease the adoption and implementation of IEEE 1547-2018 in the future.
Benefits	Streamline Technical Review; Improved Internal Efficiencies
Implementation Outlook	Progression Model Level 2

Recommendation #21 Back to List of Recommendations	**Require power quality monitors at relatively large DER sites to confirm plant compatibility with the grid and to alert for unexpected power quality issues when grid conditions change.** ***(Goal)***
Finding/Context	LPCs are likely to experience additional large DER installations (>250 kW) in the near-to-medium term, particularly given the launch of the Flexibility 1.0 and prospective Flexibility 2.0 programs. As a result, LPCs (in collaboration with TVA) should anticipate an issue that has arisen in other utility service areas: whether voltage drop is being modeled correctly or if adjustments should be made to the technical review approach. To confirm their technical review approach and process, LPCs could install power quality monitors at a limited number of new, large DER projects to obtain detailed data. Such equipment could also identify unpredictable power quality incompatibilities given significant changes in grid operation with DER and the potential for DER malfunction.

Benefits	Streamline Technical Review
Implementation Outlook	Progression Model Level 2

Recommendation #22 Back to List of Recommendations	**Develop DER technical review criteria as a public reference for internal and external use.** *(Goal)*
Finding/Context	The current approach for reviewing interconnection applications used by most LPCs does not adhere to an established screening process; this can lead to inconsistencies in review, process inefficiency, and applicant uncertainty. In these instances, the interconnection review process can be improved by more clearly defining and establishing different technical review levels for DER applications of different technology types and project capacities. Many utilities segment interconnection applications into three distinct categories: expedited (or simplified); Fast Track (often with supplemental screening); and full system impact studies. Examples of this segmentation include FERC SGIP, MN Distribution Interconnection Procedure, CA Rule 21, and NY Standard Interconnection Requirements. LPCs may consider adopting a similar segmentation that would be more efficient with internal resources, while providing sufficient technical review for projects that merit closer investigation. This reform would also provide interconnection applicants with a more defined and streamlined process, as well as greater transparency into an LPC’s approach. An example hierarchical approach is illustrated in the figure.

	 **Figure: Interconnection Application Processing Flow Chart** The expedited/simplified application path is for smaller (often inverter-based) generation systems (typically less than 10 kW or 25 kW, but up to 50 kW depending on jurisdiction) that do not require in-depth engineering studies. Larger inverter-based systems (>50 kW) are, meanwhile, usually screened with different levels of detail depending on plant rating, location, complexity, and interconnection type under a Fast Track approach. (Required pass-fail screening can include checks for DER certification, connection type, penetration levels, protection, impact on voltage level and potential for causing voltage fluctuations.) A Supplemental Review is applied if/when additional screens are deemed necessary as part of the Fast Track process. Supplemental review can avoid a full Detailed Study.
Benefits	Enhanced Customer Experience; Consistency & Quality; Streamline Technical Review
Implementation Outlook	Progression Model Level 2

Recommendation #23 Back to List of Recommendations	**Develop a [standard] technical interconnection requirements (TIR) document for DER.** ***(Requirement)***

Finding/Context	With increasing DER installs, sizes, and technology diversity, consistency in interconnection requirements may be difficult to maintain. Feeders are not uniform, and utilities often do not have a choice where DER are connected. It is recommended that each LPC adopt a Tennessee Valley-wide Technical Interconnection Requirements (TIR) document that is developed with TVA coordination. This type of document is common at other utilities and many jurisdictions now require it to ensure a consistent approach for evaluating and interconnecting DERs to a utility's distribution system in a safe and reliable manner. It assists in meeting new requirements and functions in 1547-2018, and can also help prepare for more complicated DER, including large and small hybrid solar system with batteries. EPRI created a generic template in 2021 that can be referenced to develop at TIR. The template offers helpful guidance and is being further evolved in 2023.
Benefits	Streamline Technical Review; Consistency & Quality; Improved Internal Efficiencies
Implementation Outlook	Progression Model Level 2

Recommendation #24 Back to List of Recommendations	**Determine grounding requirements to prevent Ground Fault Overvoltage (GFO).** ***(Requirement)***
Finding/Context	Screens for DER grounding compatibility systems (e.g., the original SGIP screen, CA Rule 21) have become outdated with the advent of inverter-based resources. It is now more difficult to cover all the system-related aspects of effective grounding using a simple transformer screen. Consequently, several jurisdictions are currently struggling with the nuances of inverters and GFO. On one hand, inverters have limited capability to sustain or tolerate terminal overvoltages, which is good news for GFO. But on the other hand, selection of the interconnection transformer high- and low- side windings may prevent monitoring the medium voltage (MV) from low voltage (LV) terminals. This is a complicating factor, as many winding configurations and neutral grounding do impact the ability of a certified DER to meet performance requirements in IEEE Std. 1547-2018. Terminal voltage of the DER will reflect the same level as the MV Reference Point of Applicability (RPA) if the connection is Yg-yg.

However, many PV plants are not compatible with a grounded wye transformer connection. Also, many utility practices specify either a Yg-Δ or Δ-y with or without ground. With these connections the DER may not be able to detect a ground fault and overvoltage on the MV. As indicated above, it is more complicated than a simple screen.

The below table may be used to identify acceptable connections for DER, including inverters. Note the four variables: the number of feeder wires, the MV and LV transformer windings, and the presence of MV sensing. EPRI has added the MV sensing variable, which is not typically included in most existing screens. This sensing normally involves a plant recloser requirement. It is required in three of the six acceptable interconnection methods listed in the table.

Note, effective grounding for utility purposes (per IEEE C62.92) is to prevent GFO. It is distinct from the safety, fire, and surge protection objectives typically found in building codes (based on NEC and IEEE Std. 142). All told, the preferred method for preventing GFO will depend on the multiple factors described above, as well as the feeder arrangement, service transformer windings, and type of DER.

Utility	MV Winding	LV Winding	MV Sense/ Trip (i.e., relay recloser) Required	Comment
3 Wire	Delta or Y	any	Yes	Pass if ungrounded
4 Wire	Yg	Yg	No	Pass
4 Wire	Yg	Delta	No	Fail (Need to check xfmr neutral impedance acceptable sizing)
4 Wire	Yg	Y	No	Fail (Exception to pass if inverter senses Vn, unlikely)
4 Wire	Yg	Y	Yes	Pass
4 Wire	Delta or Y	any	Yes	Pass (dependent on utility requirement)

Benefits	Streamline Technical Review; Consistency & Quality
Implementation Outlook	Progression Model Level 2

Recommendation #25 Back to List of Recommendations	**Consider reducing the compulsory anti-islanding test for qualified installers using certified UL 1741 inverters for DER installation ≤50 kW (with export capacity limited to 25 kW).** ***(Goal)***

Finding/Context	Many LPCs conduct in-person anti-islanding tests for all new residential-scale DER systems prior to granting permission to operate. Some LPCs even conduct anti-islanding testing on an annual basis. Very few anti-islanding test failures have been recorded to date, despite there being thousands of ≤25 kW DER installed throughout the Valley. Documented failures have typically been associated with new technology deployment, incorrect equipment being used, or poor installation wiring that was not identified by the AHJ—and all known failures have occurred at initial commissioning. Such an outcome is not surprising, given that a residential-scale inverter model listed under UL 1741 has been tested and certified that it will not unintentionally island. As such, in situ anti-islanding testing in a residential setting is relatively rare among U.S. utilities, particularly those with more systems connected to their distribution system. The hardware and software functionality that allows an inverter to operate in grid-following modes (phase-locked-loop, or PLL) is also involved in anti-islanding. Thus, there is an extremely low likelihood that an inverter will operate properly and synchronize to the grid yet somehow have a failure of anti-islanding functionality unless very high levels of DER penetration occur. Furthermore, even if a residential system did fail, its low power rating and minimal inrush capability would be unlikely to support even a small portion of the grid. Perhaps more importantly, the risk of personnel being shocked or injured conducting onsite anti-islanding tests is likely to be orders of magnitude higher than the risk of injury from residential-scale DER assets having actual unintentional islanding events that energize segments of the distribution system. LPCs might consider an optional “audit approach” to ensuring safety while minimizing the cost and effort of conducting a physical anti-islanding test at each site by only testing at selected sites, and only upon initial commissioning. For all projects, LPCs could confirm that the inverter specified for the project is listed on the California Energy Commission’s grid-support solar inverter or solar/battery inverter lists during the project application’s technical review, or even that the inverter is UL 1741 or UL 1741 SA listed (see Recommendation #20). For equipment that is not included in the CEC’s approved lists, an LPC could request specification sheets and determine whether it is acceptable for connecting to the LPC’s system. Subsequently, once a project is ready for commissioning, an LPC could conduct an anti-islanding test for new installers (or using new equipment) in its service area, though not for installers with whom the LPC has had positive experiences in the recent past. Once an installer has passed 5-10 projects with no issues, LPCs could replace their onsite

	testing with installer-supplied photographs indicating compliance with the proposed interconnection plan per its application. This is a process pioneered by CenterPoint Energy Houston (CPEH), which only conducts an anti-islanding test on DER systems installed by new installers to its service territory. For experienced installers, CPEH requires a series of photographs of equipment (meter, PV system, inverter, etc.), address signage, and correct placement of CPEH signage (e.g., on the disconnect switch and meter) to indicate compliance with the submitted single-line diagram and other utility requirements. (CPEH has subsequently ceased requiring even this photo-based process, relying on AHJs to ensure small-scale projects are installed correctly.) Of course, an LPC would retain the right to conduct an anti-islanding test on any system should a standard configuration not be used. For the majority of small-scale projects, though, the LPC would save time and resources that otherwise would be conducting site visits.
Benefits	Streamline Technical Review; Enhanced Customer Experience; Improved Internal Efficiencies
Implementation Outlook	Progression Model Level 2: selectively conduct anti-islanding tests; Progression Model Level 4: replace onsite visits with installer-supplied photo process

Recommendation #26 Back to List of Recommendations	**Consider requiring DER plant reclosers for 1-2 MW DER systems (include SCADA communications).** ***(Goal)***
Finding/Context	Experience indicates longer-term benefits from requiring a plant recloser (with multifunction relay) for larger DER. It is best if the utility owns the recloser, but EPRI has seen it both ways. Depending on the interconnection transformer, medium voltage switch settings may be required. For example, if DER connection does not provide zero sequence continuity, then the inverter cannot be expected to trip for ground fault overvoltage (i.e., if Yg-y, Δ-y or Δ-yg). To obtain most of the benefits of a plant recloser without high cost, several utilities have deployed a "virtual recloser" option. In these cases, only a relay (with PT and CTs) are installed on the MV side of the plant. From the relay there is a virtual option to communicate connect/disconnect to the plant LV devices. In the plant this could be a shunt trip breaker, directly to a single inverter, or to an RTAC able to communicate to multiple inverters. If possible, it is best to avoid two MV reclosers in series to forgo the need for coordination.

	LPCs should consider adopting such an approach in advance of increased medium- and large-capacity DER installations.
Benefits	Streamline Technical Review; Consistency & Quality; Improved Internal Efficiencies
Implementation Outlook	Progression Model Level 3

Recommendation #27 [Back to List of Recommendations]	**Allow DER projects to interconnect to LPC's network grids and develop standardized technical review practices.** ***(Goal)***
Finding/Context	A few LPCs operate network distribution systems in their downtown areas. To date, some of these LPCs have not allowed DER installations to be connected to these networks. However, a growing number of utilities in North America allow DERs to be connected to their network grids, albeit often via unique approaches. Consolidated Edison of New York, which primarily operates a network system, has developed a new approach for evaluating network-connected projects. It worked with the Joint Utilities of New York to better enable screening of proposed projects. Seattle City Light, meanwhile, takes a conservative approach to ensure that reverse power flow will not occur from network-connected DER; it requires that solar output not exceed a 10% minimum load criteria. LPCs that do not yet have standardized approaches to allowing DER installations to connect to their network systems should consider developing such an approach. This might require LPCs to update their network models prior to finalizing guidelines in order to start conducting technical reviews of DER projects on their systems. In doing so, they will be better able to meet customer and installer expectations for connecting DER systems to their distribution system networks.
Benefits	Streamlined Technical Review; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 3

Recommendation #28 Back to List of Recommendations	**Consider requiring reclose blocking at the main feeder breaker to prevent out of phase reclosing.** *(Goal)*
Finding/Context	When penetration of DER begins to exceed minimum load the issue of unintended islanding may come up from protection staff and linemen. For rotating machines, and traditionally for DER in general, direct transfer trip (DTT) has been required by LPCs to address unintended islanding. For inverters, active islanding detection is normally available and reasonably effective today. Therefore, cost and maintenance have been questions by both developers and utilities. If out of phase reclosing is the primary concern regarding penetration exceeding minimum load, then voltage blocking can be a good option. In some jurisdictions, criteria have been developed to use voltage blocking as an alternative to DTT. The Joint Utilities of New York has developed example criteria. EPRI is working on several alternatives to DTT. All have pros and cons. A key learning is to first determine the specific consequences of an island to the utility and then consider what is an acceptable response time (e.g., 2 sec, 10 sec, 30 sec). If ground fault overvoltage is already covered by supplemental grounding or if plant site detection/trip is installed, then plant tripping by SCADA may be acceptable.
Benefits	Streamline Technical Review; Consistency & Quality; Improved Internal Efficiencies
Implementation Outlook	Progression Model Level 4

Recommendation #29 Back to List of Recommendations	**Provide guidance on plant recommissioning, including its required elements, triggers, and proposed schedule.** *(Goal)*
Finding/Context	LPCs provide little or no guidance to DER plant owners about their recommissioning requirements. Stipulating a clear set of recommissioning requirements and providing developer and owner training would help to confirm that both LPCs and asset owners recognize the ongoing effort that is necessary to initiate and maintain a DER interconnection to the grid. It is recommended that common recommissioning requirements be established Valley-wide. Time-based recommissioning requirements include regular testing of basic protective and control functions. Depending on the type of

	equipment, these tests can occur in a timeframe ranging from 1 to 10 years. Proper time-based testing often identifies issues before they escalate into problems that may affect the reliability of the interconnection and influence the reliability of the grid. Event-based recommissioning requirements may include more extensive testing than time-based recommissioning requirements. These requirements may involve software version changes, software or parameter modifications that change the DER's rated values, major component or module replacement, or major equipment changes (e.g., transformers, circuit breakers, etc.). Alert-based recommissioning requirements may occur due to automated notices of operation outside of expected parameters. These notices may be provided by devices such as automated metering systems, system-checks, or PQ monitoring as part of protective relay packages. The alerts provide the basis for an analysis that will determine the need and scope of a recommissioning effort. All told, developing publicly available recommissioning guidelines will, on both a regularly scheduled time basis as well as event basis, limit the surprise to both the LPC and the DER owner when recommissioning is required.
Benefits	Enhanced Customer Experience; Improved Internal Efficiencies; Consistency & Quality
Implementation Outlook	Progression Model Level 4

Technical Review: Energy Storage Systems (ESS)

Recommendation #30 Back to List of Recommendations	**Explicitly define energy storage systems (ESS) as an eligible facility in interconnection rules and update utility interconnection documents – including application forms, study agreements, and interconnection agreements accordingly.** ***(Goal)***
Finding/Context	Two fundamental barriers to ESS interconnection are the lack of inclusion of storage in interconnection rules and a lack of clarity about whether and how existing interconnection rules (and related documents, such as application forms and agreements) apply to storage systems. In many jurisdictions, including within the Tennessee Valley, ESS are not explicitly included under the definition of eligible facilities. Also, applicable interconnection rules do not always adequately reflect the operating capabilities of ESS (e.g., export limiting), which may limit the beneficial and flexible services that storage can provide to the grid.

	These factors can pose a barrier to timely and cost-efficient interconnection and project financing. TVA, in collaboration with the LPCs, should clearly define what an ESS is in interconnection rules, and each LPC's DER interconnection application, interconnection agreement, and (future) technical interconnection requirements (TIR) should subsequently be updated to include this definition. Further, LPCs should clearly state in their updated documents that their stipulations apply to the interconnection of new standalone ESS, as well as ESS paired with other generators, such as solar PV systems. The following definition for ESS uses the structure of the definition of ESS found in existing interconnection standards and guidelines, including IEEE 1547-2018 and P1547.9. This definition is technology agnostic and should allow for a range of different energy storage types: ***Energy Storage System** or ESS is defined as a mechanical, electrical, or electrochemical means to store and release electrical energy, and its associated interconnection and control equipment. For the purposes of these Interconnection Procedures, an Energy Storage System can be considered part of a DER or a DER in whole that operates in parallel with the distribution system.* After defining ESS (in collaboration with TVA), an LPC's interconnection procedures should explicitly allow ESS to interconnect (with explanation of connection requirements and associated guidance). Information captured in the DER interconnection application should acknowledge that ESS can be used to limit export to the grid in some or all hours. Further, the application forms should include fields for information on the type of energy storage technology to be installed, any proposed operating profile and/or use, both kilowatt (kW) capacity and kilowatt-hour (kWh) storage values, and other information that is particularly relevant for reviewing an energy storage application. Finally, acceptable methods that can be trusted to enforce export controls should be specified to avoid the need to conduct customized review of the export controls for every interconnection application.
Benefits	Streamlined Technical Review; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 2

Recommendation #31 Back to List of Recommendations	**Define and describe the requirements and use of Power Control Systems (PCS), which are essential to capturing the advanced capabilities of storage.** *(Goal)*
Finding/Context	Because many ESS systems will be designed to control or manage export, interconnection rules and procedures need to recognize and define both non-export and limited-export capabilities. Some interconnection procedures today already define non-export, but few recognize limited-export specifically. In addition, many of the DER installed going forward are likely to use a PCS device to limit the export of energy to the distribution system. The PCS may be used alone or in conjunction with other means of controlling export, such as a utility grade relay. To capture the advanced capabilities of ESS, TVA and LPCs should collaborate in developing interconnection rules that describe the requirements and use of PCS. LPCs should subsequently incorporate these definitions into their interconnection procedures. Following are definitions for PCS and related concepts: • ***Power Control System*** *or* ***PCS*** *means systems or devices which electronically limit or control steady state currents to a programmable limit.* • ***Non-Export*** *or* ***Non-Exporting*** *means when the DER is sized, designed, and operated using agreed-to acceptable methods, such that the output is used for Host Load only and no electrical energy (except for any Inadvertent Export) is transferred from the DER to the Distribution System.* • ***Limited Export*** *means the exporting capability of a DER whose Generating Capacity is limited by a defined and agreed-to configuration or operating mode.* • ***Host Load*** *means electrical power, less the DER auxiliary load, consumed by the Customer at the location where the DER is connected.* • ***Inadvertent Export*** *means the unscheduled export of active power from a DER, exceeding a specified magnitude and for a limited duration, generally due to fluctuations in load-following behavior.* .
Benefits	Streamlined Technical Review; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 2

Recommendation #32 Back to List of Recommendations	**Define and Distinguish Nameplate Rating and Export Capacity in interconnection rules.** *(Goal)*
Finding/Context	DER with ESS often limit their output using a PCS, relay, or other means. It is useful for Valley-wide rules and LPC interconnection procedures to have a defined term that describes the maximum amount

	of this limited output. The term Export Capacity is recommended, which can be contrasted with the DER's full Nameplate Rating: ***Export Capacity*** *means the amount of power that can be transferred from the DER to the Distribution System. Export Capacity is either the Nameplate Rating, or a lower amount if limited using an acceptable means.* ***Nameplate Rating*** *means the sum total of maximum rated power output of all of a DER's constituent generating units and/or ESS as identified on the manufacturer nameplate, regardless of whether it is limited by any approved means.*
Benefits	Streamlined Technical Review; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 2

Recommendation #33 Back to List of Recommendations	**Define Operating Profile and Operating Schedule in interconnection rules.** *(Goal)*
Finding/Context	DER with energy storage can control their import and export according to a fixed schedule, or operating schedule. DER based on solar generators (without ESS) have a maximum possible output that is less than the DER's Nameplate Rating. This is often called a solar output profile. It is useful for Valley-wide rules and LPC interconnection procedures to have a defined term that describes the maximum output possible in a particular hour based on the DER's operating schedule or resource characteristics (e.g., solar output profile). It is recommended that this term be called the operating profile: ***Operating Profile*** *means the manner in which the distributed energy resource is designed to be operated, based on the generating prime mover, Operating Schedule, and the managed variation in output power or charging behavior. The Operating Profile includes any limitations set on power imported or exported at the Point of Interconnection and the resource characteristics, e.g., solar output profile or ESS operation.* ***Operating Schedule*** *means the time of year, time of month, and hours of the day designated in the Interconnection Application for the import or export of power.*
Benefits	Streamlined Technical Review; Readiness for Future System Evolution

Implementation Outlook	Progression Model Level 2

Recommendation #34 Back to List of Recommendations	**Update interconnection requirements to identify a list of acceptable methods that can be trusted and relied upon to enforce export controls.** ***(Goal)***

Finding/Context

Relying on customized review of the export controls for every ESS interconnection application is a significant barrier for ESS deployment. Non-standard types of export control equipment will continue to need customized review, but interconnection requirements should be updated to identify a list of acceptable methods that can be trusted and relied upon by both the interconnection customer and the LPC.

It is recommended that six export control methods be adopted in procedures across the Valley and, and if one is utilized, that the Export Capacity specified in the application be used by the utility for evaluation during the screening and study process (see Table).

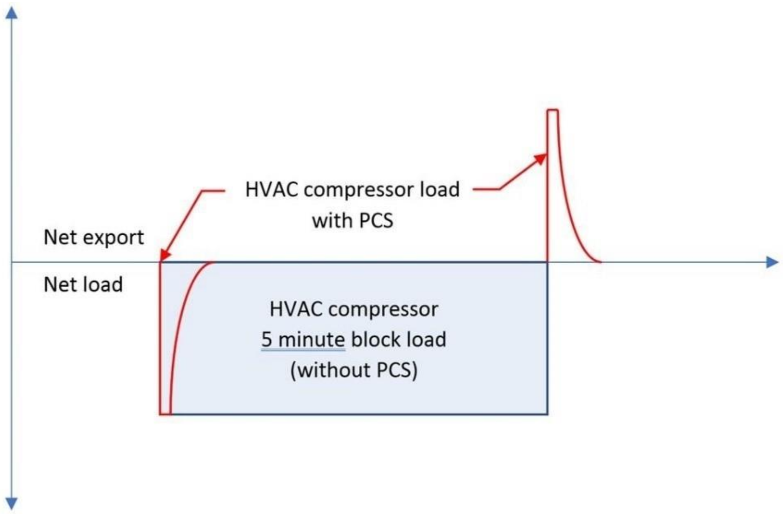
Acceptable Export Control Methods

	For Non-Exporting DER	For Limited-Export DER
a) Reverse Power Protection (Device 32R*)	Yes	
b) Minimum Power Protection (Device 32F*)	Yes	
c) Relative Distributed Energy Resource Rating	Yes	
d) Directional Power Protection (Device 32*)		Yes
e) Configured Power Rating		Yes
f) Limited Export Utilizing Certified PCS	Yes	Yes
g) Limited Export Using Agreed-Upon Means	Yes	Yes

Beyond the recommended eligible export controls listed in the table, a seventh export control option can allow for the use of any other method so long as LPCs (in collaboration with TVA) approve its use.

	Once a project's means of safely and reliably controlling export have been established, a project can be reviewed (screened and/or studied) with the assumption that it will control export as specified.
Benefits	Streamlined Technical Review; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 2

Recommendation #35 Back to List of Recommendations	**Update screening and study processes to specify how limited- and non-export projects are reviewed.** ***(Goal)***
Finding/Context	LPC interconnection application forms should be updated to include information about the ESS and, where export controls are used, the type of export control and the equipment type and settings that will be used. As a next step, during its completeness review and once screening or study commences, an LPC should verify that the equipment used is certified, where necessary, and/or is otherwise acceptable for the intended use. LPCs can also consider verifying the export control methods used to meet defined export control criteria (see Recommendation #34). For example, the utility should verify whether the applicant is using a PCS that has been tested under UL 1741, and for relays it should verify whether the relay is utility grade. Acceptable relay equipment is subject to utility-specific requirements which may be contained in handbooks or other addenda to technical interconnection requirements. If it doesn't already, LPCs may consider maintaining preferred equipment lists of specific equipment types and model numbers, allowing developers to easily include acceptable equipment in initial applications. An engineering evaluation of the proposed DER may still be needed to ensure proper relay configurations and settings are noted. Commissioning tests may include additional testing to ensure relays, PCS, or other export control devices are appropriately installed with the correct settings.
Benefits	Streamlined Technical Review; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 3

Recommendation #36 Back to List of Recommendations	**Permit interconnection agreements to allow inadvertent export from "non-export" energy storage systems.** *(Goal)*
Finding/Context	Energy storage systems that receive an Interconnection Agreement to operate in “non-export” or “limited-export” operating mode are typically not allowed to inadvertently export power for short, non-coordinated periods of time beyond the specified export limit. It is an LPC’s decision as to whether to allow or disallow inadvertent export, but it should consider allowing ESS to export energy in a non-coordinated way for a limited amount of time. It is EPRI’s understanding that LPCs do not include language on inadvertent export from ESS at its customers’ premises. Prohibiting storage systems from ever exporting can be challenging—and costly due to the potential for connected loads to rapidly change, requiring an expensive control system. The concept of inadvertent export for varying load conditions is illustrated in the figure.  **Figure** **Illustration of Inadvertent Export of Non-Exporting DER with Energy Storage and Varying Load** An LPC could consider allowing ESS to export energy beyond the specified limit in a non-coordinated way for a limited amount of time, while easing its technical review for such proposed projects. For example, California’s Rule 21 and Hawaii’s Rule 22 both allow energy storage systems to export power for up to 30 seconds; IEEE Std 1547-2018 also specifies that a DER shall limit its active power output to not greater than the active power limit set point (P_limit) for no more than 30 seconds. These rules appear to be working well, with no issues yet reported.

	In March 2019, Underwriters Laboratories (UL) published the first phase of a certification requirement decision (CRD) on Electronic Power Control Systems that adds new tests in UL1741 to address compliance verification for “non-export” and “limited-export” energy storage systems. (UL develops CRDs in response to emerging testing requirements that are not yet addressed in the referenced standard.) The CRD’s purpose has been to test and certify the non-exporting and limited-exporting functionality of PCS devices. One of the key metrics evaluated by the CRD is the Open Loop Response Time (OLRT) of the Power Control System, i.e., the time it takes the system to respond to changes in generation or load. The CRD sets a maximum OLRT of 30 seconds but both utilities and vendors acknowledge that response times less than 30 seconds may be needed to coordinate with distribution grid regulation and control time constants. The CRD, which is expected to be formally incorporated into UL1741 in 2023, harmonizes the OLRT using the definitions stipulated in IEEE Std 1547-2018. It ultimately allows a device to demonstrate that it is preventing export or to confirm that a fixed maximum export is not exceeded. LPC’s across the Tennessee Valley could use this CRD, soon to be folded into UL1741, to monitor whether load displacement projects are exporting real or reactive power to the grid.
Benefits	Streamlined Technical Review; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 3

Recommendation #37 Back to List of Recommendations	**Adopt interconnection screens that distinguish between the Nameplate Rating and the Export Capacity of a project to accurately evaluate the distribution system impacts of export-controlled ESS.** *(Goal)*
Finding/Context	Interconnection screens are designed to evaluate whether there is a risk that a proposed project will perversely impact the distribution system. The screens cover a variety of different concerns, including thermal, voltage, protection, grounding, networks, etc. Some screens evaluate a project’s likely impacts based upon the “size” of the project and, though the screens are not explicit, it is generally assumed that the size refers to the Nameplate Rating of the project. In the case of export-controlled storage systems, applying certain screens using a project’s Nameplate Rating instead of its actual Export Capacity can result in an overestimation of the

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<p>project’s impact. Consequently, ensuring that each screen is written to properly distinguish between the impacts of a project with or without export control is an important way that the interconnection process can be improved for ESS projects. This can primarily be done by distinguishing between the Nameplate Rating or the Export Capacity of a project depending on the type of potential impact a screen is intended to assess.</p>
<p>Whether and how a screen needs to be modified depends on the type of impact it is designed to evaluate. If/when an LPC fully adopts the SGIP technical review process and screens for conducting technical review (see Recommendation #21), it should also modify those screens in the table for which Export Capacity is appropriate to use when assessing impacts. This includes a new inadvertent export screen recently proposed by EPRI (see Recommendation #39). (The SGIP screens that are not identified in the table do not require revision).</p>
<table>
<tr><th>Screens in which Export Capacity is appropriate to evaluate impacts</th><th>Screens in which Nameplate Ratings can still be used</th></tr>
<tr><td>Penetration Screens</td><td>Spot Network Screen</td></tr>
<tr><td>The new Inadvertent Export Screen</td><td>Protection Screens (2)</td></tr>
<tr><td rowspan="2">Transformer Ratings Screen</td><td>Service Imbalance Screen</td></tr>
<tr><td>Transient Stability Screen</td></tr>
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<tr><td>Benefits</td><td>Streamlined Technical Review; Readiness for Future System Evolution</td></tr>
<tr><td>Implementation Outlook</td><td>Progression Model Level 3
(if/when an LPC adopts the SGIP screens)</td></tr>
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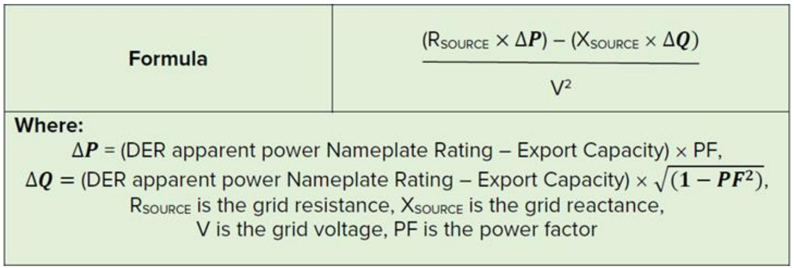
Recommendation #38 Back to List of Recommendations	**Update interconnection studies to account for the way in which an ESS project’s limited export may affect system impact study outcomes.** ***(Goal)***
Finding/Context	Interconnection studies must consider the manner in which a project has limited export when they assess impacts in the system impact study. If a proposed project uses an acceptable means of export control (described in Recommendation #34), LPCs should evaluate impacts to the distribution system using the project’s Export Capacity, except when evaluating fault current effects. (However, if the applicant has provided manufacturer test data to demonstrate that the fault current is independent of the Nameplate Rating, then an LPC should utilize the rated fault current instead).

	In addition, if the project has proposed to use an operating schedule (instead of a fixed export limit), the feasibility study and system impact study should take that profile into account if the utility has assurances that the scheduling equipment can be relied upon. The Facilities Study typically does not evaluate system impacts, therefore modifications to the Facilities Study are not recommended. An LPC's interconnection rules, system impact study agreement, and feasibility study agreement should be modified to require use of Export Capacity in the study evaluation where appropriate export controls are used; designate the use of Nameplate Rating or the rated fault current (if different) for evaluation of fault current; and require consideration of a project's operating profile.
Benefits	Streamlined Technical Review; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 3

Recommendation #39 [Back to List of Recommendations]()	**Consider implementing a new Inadvertent Export Screen into LPCs' review processes.** ***(Goal)***
Finding/Context	For interconnection of a proposed DER that can introduce Inadvertent Export, where the Nameplate Rating minus the Export Capacity is greater than 250 kW, the following Inadvertent Export screen is recommended. With a power change equal to the Nameplate Rating minus the Export Capacity, the change in voltage at the point on the medium voltage (primary) level nearest the Point of Interconnection should not exceed 3%. Voltage change should be estimated applying the following formula:  **Formula** $\frac{(R_{SOURCE} \times \Delta \boldsymbol{P}) - (X_{SOURCE} \times \Delta \boldsymbol{Q})}{V^2}$ **Where:** $\Delta \boldsymbol{P}$ = (DER apparent power Nameplate Rating – Export Capacity) × PF, $\Delta \boldsymbol{Q}$ = (DER apparent power Nameplate Rating – Export Capacity) × $\sqrt{(\mathbf{1} - \boldsymbol{PF}^{2})}$, R_{SOURCE} is the grid resistance, X_{SOURCE} is the grid reactance, V is the grid voltage, PF is the power factor
Benefits	Streamlined Technical Review; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 3 (if/when an LPC adopts the SGIP screens)

Recommendation #40 Back to List of Recommendations	**Adapt screening results so that they provide relevant and useful data that can inform changes to a DER (including ESS) application that enable it to pass a failed screen and avoid the need for grid upgrades.** *(Goal)*
Finding/Context	Ideally, when screening results are provided, full information about each screen should be given so that applicants are able to ascertain exactly what changes to their DER system are needed to pass failed screen results. Further, suggested design changes are also helpful to reducing interconnection hurdles (though an LPC may not feel this is within its realm of responsibility in the interconnection process). The type and amount of data provided by utilities varies significantly, with some utilities providing a simple "pass" or "fail" for each screen and others offering more detailed data. If/when an LPC adopts the SGIP screens for use in technical review, it might consider supplying the screen results data presented in the following tables.
Benefits	Streamlined Technical Review; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 4 (if/when an LPC adopts the SGIP screens)

SGIP Screen		**Description**	**Data to Provide**
Initial Review	2.2.1.2	15% of annual section peak load (or 100% minimum load)	Load (peak or minimum), aggregate generation (or Export Capacity), and percentage of load. For interconnection rules that integrate time-based load data into the screening process, provide the minimum load time window.
	New screen	Inadvertent Export voltage change screen	Provide values in the equation: $\frac{(\boldsymbol{R}_{SOURCE} \times \Delta \boldsymbol{P}) - (\boldsymbol{X}_{SOURCE} \times \Delta \boldsymbol{Q})}{\boldsymbol{V}^2} = \Delta \boldsymbol{V}$
	2.2.1.3	Spot network (5% of network peak load or 50 kW)	Peak load, aggregate generation on network, and percentage of load.
	2.2.1.4	10% of maximum fault current	Aggregate generation fault current on circuit, distribution circuit max fault current, percentage of max fault current, assumptions for customer's DER (e.g., fault current = 1.2x inverter Nameplate Rating).
	2.2.1.5	87.5% of short circuit interrupting capability	Short circuit interrupting rating at limiting (lowest rated) equipment in-line with DER, aggregate DER fault current contribution, distribution circuit max fault current nearest PCC, total short circuit current, percentage of short circuit interrupting rating.
	2.2.1.6	Line configuration	Distribution line type, interconnection (customer service) type.
	2.2.1.7	Shared secondary transformer 20 kW	Aggregate DER rating (or export) on shared secondary, for screens that use 65% of transformer rating instead of 20 kW provide transformer rating and percentage of rating.

	2.2.1.8	Single-phase imbalance	Transformer rating, imbalance as percentage of rating.
	2.2.1.9	10 MVA transient stability	Aggregate generation, whether there are known transient stability limitations.

SGIP Screen		**Description**	**Data to Provide**
Supplemental Review	2.4.4.1	100% minimum load	Min load, aggregate generation (or export), percentage of load, time period under consideration (e.g., hours of the day based on fixed vs. tracking PV).
	2.4.4.2	Voltage and power quality	This list is not exhaustive and would be dependent on the applied criteria. E.g., if non-bidirectional regulators experiencing reverse flow: maximum reverse power at regulator; If overvoltage is flagged at minimum load: maximum reverse power with customer's DER, maximum reverse power before triggering voltage limit violation.
	2.4.4.3	Safety and reliability	This list is not exhaustive and would be dependent on the applied criteria. E.g., conductor loading: limiting conductor ampacity, total current, loading as a percentage of ampacity.
Covering all screens			kW of existing DER in-line section and DER ahead in queue.

Recommendation #41 Back to List of Recommendations	**Provide analysis of alternate options in ESS impact study results.** ***(Goal)***
Finding/Context	System impact studies have a broad scope and require detailed analysis. Identifying the universe of data and information to be provided in study results is therefore challenging and interconnection rules typically describe such results in broad terms. From the developer perspective, a transparent, collaborative process between the utility and developer that helps to refine the proposed DER design in a manner that maximizes the benefits to the customer while also benefitting, or at least minimizing the impact on, the distribution system is ideal. A step in this direction, without completely revamping the interconnection process, is to provide a limited analysis of alternative DER configurations. For efficiency, studying these alternative configurations would best be done during the normal timeframe of the study, rather than requiring restudy after the results are delivered. Some utilities regularly provide this type of analysis as part of the study results, though they vary in how that information is evaluated or presented. For example, a reduced Nameplate Rating or modified power factor (PF) setting may be noted as a less expensive solution to an identified upgrade.
Benefits	Streamlined Technical Review; Readiness for Future System Evolution

Implementation Outlook	Progression Model Level 4

Recommendation #42 Back to List of Recommendations	**Improve verification processes to ensure DER/ESS compliance with the terms of the interconnection agreement and streamline associated labor requirements.** ***(Goal)***
Finding/Context	As DER, including ESS, grid interconnection requests grow, in-person validation, such as witness testing and anti-islanding testing, is likely to become less sustainable for small DER systems. Small, factory integrated systems are well-tested by Nationally Recognized Testing Laboratories (NRTLs), responsible for safety testing and product certification, to prevent unintentional islanding and other potentially dangerous modes of operation. No documented cases of modern, factory-integrated small systems unintentionally energizing the area EPS are known to exist. EPRI surveyed a number of utilities on future best practices for functional validation of DER installation. Almost without exception, these utilities favored remote and continuous validation processes via two-way communication, telemetry, or advanced metering infrastructure (AMI) over in-person testing. IEEE Std. 1547-2018 requires all systems to provide a standardized communications means, which can be leveraged for verification. The IEEE Std. 1547-2018 requirement that all systems provide a standardized communications means, which can be leveraged for verification, positions utilities to overcome several shortcomings associated with in-person testing, including: 1. In-person testing captures only one snapshot in time and thus cannot account for all corner cases in grid parameters; it also cannot foresee the impact of future settings or firmware changes. 2. In-person testing unnecessarily exposes workers to live equipment. 3. In-person testing requires sufficiently trained personnel, which are in short supply and can cause scheduling issues. 4. In-person testing is very expensive, one truck roll for such testing can cost well over $1,000. LPCs might review their current methods for validating DER compliance with interconnection terms and consider integrating new of modified approaches that offer the ability to verify proper operation on an ongoing basis (rather than in one instance), ease enforcement, reduce staff exposure to hazards, and lessen the

	demands on trained personnel (thereby freeing them up to tackle more important tasks).
Benefits	Streamlined Technical Review; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 4

<table>
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<th>Recommendation #43
Back to List of Recommendations</th>
<th>Implement a workable approach for assessing ESS with fixed scheduling. (Goal)</th>
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<td>Finding/Context</td>
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<p>Where DER penetration is high, hosting capacity determined by traditional means may be artificially low (i.e., basing a DER’s potential grid impacts according to its full Nameplate Capacity as if it were generating non-discriminately). Energy storage, when properly coordinated, can mitigate the impacts of intermittent renewable generation and address grid capacity constraints that may arise during certain times of the day, week, month, season, or year. Applying a fixed schedule that can adjust import and/or export from ESS and hybrid systems, such as solar-plus-storage plants, is one possible method of achieving this coordination.</p>
<p>Following are three primary ways to determine a fixed schedule, along with their respective pros and cons.</p>

Utility-defined scheduling – This approach, adopted in Massachusetts, involves the utility selecting and applying a schedule to all applications where ESS is prevented from exporting energy, and is generally designed to avoid periods of peak export from solar. Massachusetts utilities require that standalone ESS comply with a single pre-defined schedule for the whole territory or be subject to upgrades to support circuit switching conditions. This allows the utilities to potentially ease study by knowing when all ESS are charging or discharging. However, the schedule is not specific to the feeder constraints, and may interfere with ESS use cases (e.g., by requiring charging when it would be financially beneficial to discharge). The applicant/developer is responsible for ensuring the installed equipment adheres to the schedule set forth by the utility.

<table>
<tr><th>Pros</th><th>Cons</th></tr>
<tr><td>Simplifies study</td><td>Doesn’t fully support ESS versatility</td></tr>
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Simplifies operations	Lacks flexibility
Easy to conform to and enforce	Limits potential use cases

2. **Scheduling based on feeder-specific hosting capacity analysis (HCA)** – This method, being pursued by the largest investor-owned utilities in California, is similar to the fixed schedule approach described above, but observes schedules specific to individual feeder conditions which may be highly variable from one feeder to the next. The California process, currently being implemented, would allow applicants to propose “Limited Generation Profiles” that are designed around an HCA profile (with a -10% buffer). It requires an HCA tool, updated regularly, conducted at a granular level (i.e., 576 hours), with detailed results available to potential applicants. (HCA results are based on the past year’s load profile.) The applicant/developer is responsible for determining the schedule in accordance with the HCA provided by the utility and ensuring the installed equipment adheres to the schedule set forth by the utility.

Pros	Cons
Greater granularity	Computationally intensive
Flexible	Somewhat complicated
Enables greater use cases	A work in progress

3. **Applicant-provided schedules** – This more iterative approach involves the utility identifying system constraints during the interconnection screening or study process, and if desired by the applicant/developer, undertaking further evaluation on a more granular time scale to determine if the constraints are limited to certain times of the day/year. Applicants are then afforded the opportunity to amend their system design and/or introduce a schedule.

Pros	Cons
Greater flexibility	Significant data collection
Increased utility/applicant coordination	Considerable utility review/analysis
	Can be contentious

LPCs could consider implementing one of these methods as they determine how to address what is likely to be an increasing volume of schedule-based ESS interconnection requests in the future.

Benefits	Streamlined Technical Review; Readiness for Future System Evolution; Consistency & Quality

Implementation Outlook	Progression Model Level 5

Recommendations: Internal Infrastructure

Recommendation #44 Back to List of Recommendations	**Establish an internal, cross-functional team at each LPC to design, communicate implementation expectations, and monitor end-to-end performance against standardized practices on DER interconnection.** ***(Goal)***
Finding/Context	Many LPCs understand the growing role DER will have in the future of the electric power system, and the reality that the current organizational structure of the utility is not optimally designed to handle the multitude of DER-related issues that a distribution company will increasing encounter. As such, it could be valuable for each LPC to create an internal group consisting of Energy Services, Engineering, Billing, Metering, Distribution Planning, and other groups potentially impacted by DER (now and in the future) to efficiently coordinate the LPC's response to DER-related issues. Such a cross departmental team, empowered with sufficient management backing, could enable coordination, enhance customer experience, and implement thoughtful procedural reforms such as those suggested in this document Salt River Project has, for example, successfully created a cross-organizational team. Sponsored by three utility executives at the kick-off of an ongoing interconnection process improvement effort, the initiative was recognized as a company priority, and has since resulted in the implementation of substantial – and positive – changes to the utility's practices. The creation of an interdepartmental team can also sustain a long-lasting focus on interconnection, and help resolve lingering issues as well as new obstacles to conducting efficient technical review and processing DER interconnection applications. It would provide more clarity on an LPC's policies toward interconnection and, more broadly support a unified utility strategy regarding DER deployment.
Benefits	Improved Internal Efficiencies; Consistency & Quality; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 2

Recommendation #45 Back to List of Recommendations	**Create internal utility checklists for how interconnection applications are tracked and processed.** *(Goal)*
Finding/Context	Some LPCs do not have a standard utility checklist for processing interconnection applications. However, other LPCs report that a defined list of internal processing steps and quality checks that each incoming application must pass to arrive at an approval decision can be helpful. Internal review checklists also assign responsibility to utility staff/departments for performing identified items and define the associated timelines for completing them. Checklists may be set up as fully manual or include different levels of automation to track progress and communicate next steps (e.g., simple macros embedded in Excel worksheets to fully automated review steps programmed into third-party software or even online portals). For each LPC, such a checklist could be one task for the cross-functional interconnection team (see Recommendation #44) to produce.
Benefits	Internal Efficiencies; Consistency & Quality; Streamline Technical Review
Implementation Outlook	Near term / Progression Model Level 2

Recommendation #46 Back to List of Recommendations	**Identify and train employees to provide backup/redundancy for each interconnection personnel's function to overcome potential extended absences or bandwidth issues.** *(Goal)*
Finding/Context	LPCs in the Tennessee Valley are regulated by TVA. Currently, there are no mandated time-lines for LPCs to complete the review of a DER interconnection application. Even though no such mandate exists, it would be advisable for LPCs to identify and train employees to be able to take over specific interconnection personnel roles in the event of extended staff absences or other encountered bandwidth issues. The current process for handling redundancy of employee competencies at LPCs appears to be fairly informal. For example, if a technician is out, there's an expectation that someone will "pick up the slack" in terms of communication with members and installers, or queries will only be responded to once the designate point-of-contact returns from being out of office. A more formalized process for ensuring coverage during staff absences would allow for more consistency of application review, ensure stable process flow, meet (future) internal timeline goals, and potentially lead to higher customer satisfaction.
Benefits	Enhanced Customer Experience; Consistency & Quality
Implementation Outlook	Progression Model Level 2

Recommendation #47 Back to List of Recommendations	**Enforce requirement that the sale/transfer of an interconnected DER system be reported to LPCs.** ***(Goal)***
Finding/Context	LPCs stipulate different customer requirements in their interconnection agreements for being notified of when a sale or transfer of a DER system to another owner has occurred. It is, furthermore, unclear how stringently LPCs enforce this requirement and how many customers comply with it. This situation can undermine the accuracy of the DER asset ownership information the utility has on file. Correctly identifying the owner of a connected DER – and being able to communicate with them – is important for maintaining distribution grid safety. An immediate solution would be to ask all LPC customers who request a “Stop Service” or “Move Service” to indicate whether they have an interconnected DER, and if so, to share the new owner’s contact information. Once an LPC improves the accuracy of the information it has on customer-sited DERs in its customer database (or GIS), customer service representatives would only need to question those customer accounts that have indicated DER system ownership. Regardless of the approach, LPCs are encouraged to collect information on the transfer of DER ownership in-line with customer contractual agreements.
Benefits	Improved Internal Efficiencies; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 2

Recommendation #48 Back to List of Recommendations	**Add details on DER installations (including DER <50 kW) to the LPC’s Geographic Information System (GIS), and automate the process.** ***(Requirement)***
Finding/Context	Conducting accurate DER interconnection application reviews requires knowing what existing DER projects are already interconnected to the feeder of interest. Populating DER projects in an LPC’s GIS mapping system can provide this information, as well as support Grid Planning in longer-term activities. Many LPCs currently note DER projects graphically in their maps, though without sufficient details to use when conducting DER interconnection technical reviews or other utility planning activities. At current penetration levels, leaving customer-owned DER assets out of such modeling might not result in misleading assessments of

	an LPC’s system, though as more DER is added, their absence could lead to false conclusions. Furthermore, including DERs in the utility’s system would allow linesmen and other field staff to see DERs in the utility’s maps, improving their safety. To rectify this, LPCs should add the following details to its GIS: DER technology type(s), unique ID, location, nominal capacity, nominal voltage, nominal power factor, and operating mode (for storage), and tying the installation to a specific service transformer and customer location. Eventually, LPCs would also collect more advanced DER data on systems greater than 50 kW, including operating active/reactive power, impedance, grid support capabilities/mode, and dynamic/harmonic properties, as such information would be beneficial for conducting more detailed studies. For those LPCs with relatively high and/or growing DER project development in their service area, automating the process of adding DER projects to the utility’s GIS is likely worthwhile – and could be fairly straightforward. Staff at BrightRidge, the Johnson City LPC, recently automated the updating of its GIS with new DER projects. After a BrightRidge staffer manually enters an alert for a new DER project into the utility’s NISC CIS, it automatically triggers the project’s addition into the utility’s ESRI GIS, along with accompanying text on the DER system's capacity and whether BESS is included. BrightRidge reports that creating this automated step was "fairly simple" and that it "did not take much time" for the utility’s IT and mapping departments to set up. Such an effort could be a worthwhile model for some LPCs to emulate. It would help enable future power flow modeling to account for all DERs, and well as the development of hosting capacity maps. It would also represent a first simple step toward increasing automation of DER-related analyses and information storage for other LPC software applications that would improve staff productivity. Future automation efforts, for example, might include setting up an automated check on service transformer capacity.
Benefits	Improved Internal Efficiencies; Consistency & Quality; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 2 (Basic information entry) Progression Model Level 3 (Advanced information entry) Progression Model Level 4 (Automated information entry)

Recommendation #49 Back to List of Recommendations	**Develop and institute quality assurance programs on interconnection review processes conducted by LPC engineers.** ***(Goal)***
Finding/Context	To ensure consistent and systematic review of applications, LPCs should develop quality assurance (QA) programs for their field engineering departments that are engaged in the interconnection review process. To this end, it is recommended that standard templates be used with defined fields for conducting technical studies. Some utilities have tackled quality assurance through their engineering design manual and corporate DER roadmap, both of which have been useful. Key to any LPC effort is to establish documentation procedures, including those for tracking comparative review costs, that can build utility learning. Additional activities could encompass incorporating macros into templated utility forms – which can be shared with applicants – that provide prefabricated written descriptions of technical review findings. The overarching goal of a QA program is to ensure systematic review as well as utility education. In this way, subjective approaches (e.g., engineering “rules of thumb”) can be replaced with confirmed industry best practices and delivered in a consistent fashion.
Benefits	Consistency & Quality; Internal Efficiencies
Implementation Outlook	Progression Model Level 3

Recommendation #50 Back to List of Recommendations	**Evaluate effective, low-cost monitoring and control options for mid-sized DER systems (250 kW to 2 MW).** ***(Goal)***
Finding/Context	Advances to monitoring and control systems are needed to achieve increased distribution automation and better integrate DERs into distribution systems and with bulk markets. This is an evolving area without standards and represents a common challenge across many utility jurisdictions with increasing DER penetrations. Current utility practices generally address the same functions via a wide range of implementations. Telemetry (monitoring/ metering), control unit (remote terminals, plant controllers), and power output regulation (external recloser or direct control of DER) are, for example, achieved in a variety of ways. Control practices are the least evolved (until now typically only required for ≥1-MW exporting facilities) and exclude smaller DER plants. Generator control is rare. Meanwhile, recloser control is most common and

	may include some protection functions but is limited to on/off switching. Monitoring and control issues and questions that LPCs may consider addressing in the future include: • Is low-cost metering, protection, and control for smaller DER needed with increased penetration levels? • What is the relative cost vs. function for monitoring without control at 250 kW? • What technology and network options exist that most cost-effectively meet the monitoring and control needs? • Is recloser control, limited to DER switching, best in the long run? • Can remote terminal unit (RTU) generator control, which has not yet been defined or deployed, support future distribution automation? It is recommended that LPCs examine the cost-benefit of instituting different defined levels of telemetry (e.g., monitoring, controlling, fast/slow) and various local control capabilities. This direction is supported by IEEE 1547-2018, which requires communication and controllability in all DERs in the future. The question will be cost-benefit and feeder readiness to integrate DER control. The additional project cost for SCADA telemetry in some jurisdictions is in the range of $50,000 (plus ongoing monthly fees)—a significant sum to project owners. EPRI expects there will be different levels depending on size, location, degree of automation, and need for control. The real time automation controller (RTAC) option, being deployed by some utilities for smaller and commercial-sized plants, is considered an excellent step. Essentially a plant controller, an RTAC type device provides the capability of local logic and generation control. Also, the plant controller may acquire more information for appropriate recloser operation.
Benefits	Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 3

Recommendation #51 Back to List of Recommendations	**Automate interconnection application status emails, including confirmation of completed application submission.** ***(Goal)***

Finding/Context	Once an LPC is able to validate that a DER interconnection application is complete, it can consider communicating application status to applicants via automatically-generated emails. As a project moves through the interconnection review process, other automatically-generated emails – using standardized templates – can be sent to provide applicants with updates on the status of their applications. If a problem arises (e.g., a missing document or project detail needed for technical review), standardized text can be developed to alert applicants of associated issues. Automating communications with customers can reduce utility workload, while providing up-to-date information to DER interconnection applicants on the status and potential needs of their project applications. Such automation could potentially be enabled via an LPC's existing workflow management system. Adopting an online portal would typically include automated communications capabilities.
Benefits	Enhanced Customer Experience; Improved Internal Efficiencies
Implementation Outlook	Progression Model Level 3: workflow automation Progression Model Level 4: online portal adoption and use

Recommendation #52 Back to List of Recommendations	**Track differences between indicative cost estimates (or original customer deposits once instituted) and subsequent detailed cost estimates provided during detailed design and in the final developer invoice; move towards root cause analysis for large and/or consistent deviations.** ***(Goal)***
Finding/Context	Final costs to applicants for utility review of an interconnection application and/or construction needed to enable system upgrades can often vary from early utility estimates for a variety of reasons. Creating a formal feedback loop for informing LPCs' engineering staffs of cost changes that occur – and determining why they occur – can educate utilities about how to better estimate costs, thereby minimizing variances that can jeopardize DER project economics. Improved utility estimates can provide project developers more clarity on whether their projects' economics are viable and worth pursuing, while ensuring that LPC engineers are consistent in their handling of DER interconnection-related upgrades. To improve cost predictability for customers, LPCs might consider publishing a unit cost guide containing a list of standard prices for typical interconnection facilities and equipment. This practice has been adopted in California, where the state's three large investor-owned utilities publish and periodically update guides (see examples here and here). This information has been

	helpful to customers in understanding and predicting the costs of connecting their projects to grid, in some cases well before initiating the application process. Unit guides can also help to promote cost consistency across projects.
Benefits	Consistency & Quality; Enhanced Customer Experience
Implementation Outlook	Progression Model Level 4

Recommendation #53 Back to List of Recommendations	**Create maps detailing distribution system hosting capacity for internal and external use.** ***(Goal)***
Finding/Context	Accurate, up-to-date maps of an LPC's distribution system can play a useful role for both the utility and potential DER interconnection applicants. For the LPC, having such information can support a more rapid review of an interconnection application on a specific feeder. For applicants, access to a more simplified version of the map, specifically one that indicates remaining hosting capacity for new DER projects, can allow them to be more selective in the project types and specifics they pursue (e.g., capacity, technology deployed, etc.). By increasing visibility into the characteristics and feasibility of individual circuits, these maps can save both customers and utilities time and money. Most utilities first develop hosting capacity maps for internal use. Information concerning its generation load can be largely automated once an LPC's interconnection database is able to sync with the utility's backend system (e.g., CYME or Synergi power flow analysis tool and GIS). Once internal hosting maps are completed, they can be modified for external use. Updating hosting capacity maps on a monthly basis is the accepted practice by utilities in California and New York. For more information on hosting capacity maps, see EPRI report: *Recommended Best Uses and Expectations for Public-facing Hosting Capacity Maps*.
Benefits	Enhanced Customer Experience; Streamlined Technical Review
Implementation Outlook	Progression Model Level 4: internal maps Progression Model Level 5: external hosting capacity maps

Recommendation #54 Back to List of Recommendations	**Launch initiative to clean up inaccurate data in GIS and other data systems in order to enable automation of technical review and use of future DERMS.** ***(Goal)***

Finding/Context	A number of LPCs report that their GIS is often incomplete when it comes to DERs, and may even include incorrect information. As such, the information pulled from their GIS for analyses could lead to erroneous conclusions. The challenge LPCs face with inaccurate GIS data (as well as “bad” data in other utility databases) is not unique; in fact, the issue appears to be ubiquitous among North American utilities. Improving the accuracy of an individual LPC’s GIS will not be an easy task (much less more than 150 LPC GISs): other near-term priorities often secure budgets and executives’ support while GIS or other database improvements efforts end up being postponed. Still, improving the accuracy of an LPC’s GIS would provide numerous benefits, including reduced time and effort in confirming GIS information during interconnection reviews. It would also allow for greater potential automation in reviewing DER interconnection applications, and would be key to both safely operating a distribution energy resource management system (DERMS) that dispatches DERs in line with system needs and constraints, as well as enabling flexible interconnections (see Recommendation #57). All told, LPCs should consider proposing and implementing a GIS improvement initiative, the benefits of which would likely extend beyond DER interconnection application review and operation.
Benefits	Internal Efficiencies; Streamline Technical Review; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 4: GIS data clean-up Progression Model Level 5: DERMS implementation

Recommendation #55 Back to List of Recommendations	**Replace LPCs’ typical use of Excel spreadsheets to manage DER interconnections with a new utility software system to track, integrate documents, and process interconnection requests across the entire lifecycle.** ***(Goal)***
Finding/Context	A number of LPCs recognize that the current manner in which they track DER interconnections, via a Microsoft Excel spreadsheet (stored either in shared folders or individual’s hard drives), is insufficient for meeting the utility’s future needs for handling applications. LPCs could begin considering the adoption of an online portal to handle application submission and processing. As a result, the use of Excel spreadsheets to track and manage the interconnection queue could be reduced, if not eliminated.

	Once the initial portal is adopted, any new software system an LPC also adopts should be capable of seamlessly interfacing with the online portal for DER interconnection applications. A portal could also be integrated with an LPC's legacy systems over time. Eventually, such a combined system could be used to track, integrate documents, and process all interconnection requests across their entire lifecycle. It could also integrate with an LPC's workforce management system to assign tasks and send alarms to personnel on approaching deadlines (see Recommendation #51). The long-term goal (Level 5) would have the portal software system fully integrated into the LPC's IT systems used for business management, power flow analyses, and other applications that would allow two-way data flow and automated interconnection technical review (see Recommendation #56).
Benefits	Improved Internal Efficiencies; Consistency & Quality; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 4: Initial portal adoption Progression Model Level 5: Fully integrated portal

Recommendation #56 Back to List of Recommendations	**Fully integrate back-office systems (e.g., GIS, power flow analysis, etc.) to enable the exchange of data for interconnection review and other processes.** ***(Goal)***
Finding/Context	As LPCs update their back-office software systems, a long-term goal should be to enable their capability to autonomously extract and exchange data with other systems. Developing an integrated DER interconnection system, perhaps as part of a broader portal adoption strategy (see Recommendation #55), would enable an LPC to potentially create autonomous pre-screening and screening of interconnection applications. It could also conduct weekly or even daily data uploads to its GIS to help inform power flow analyses of the radial network. This practice is already being performed by utilities, such as Orange & Rockland in New York, Eversource Energy in Connecticut, and PHI in Maryland and the District of Columbia. One automated way to link system planning data with the interconnection application review process was developed by EPRI in 2018 (see EPRI white paper, *The Role of Automation*

in DER Interconnection, 3002013333). For a U.S. DOE project, feeder data and analytics were provided from EPRI's Distribution Resource Integration and Value Estimation (DRIVE) tool, which assesses the DER hosting capacity of distribution circuits. Automated application management was provided by Clean Power Research's (CPR's) PowerClerk Interconnect software. Decisions for first-level technical screening were enabled by interfacing DRIVE and PowerClerk using an automated service application called DRIVE Connect. The figure depicts the multiple steps involved in the automation process as applied to first-level screening.

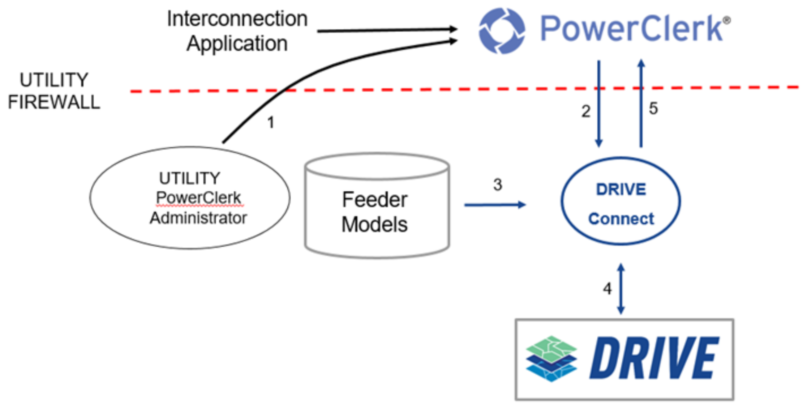

Figure
Automation of first-level technical review: process and steps

Notes: Step 1 - Administrator flags applications for DRIVE analysis (this may be all or selected depending on the jurisdiction). Step 2 - DRIVE Connect finds the project in the Engineering Review Request Queue. Step 3 - DRIVE Connect gathers circuit data for the project being analyzed. Step 4 - DRIVE Connect interfaces with DRIVE, and the latter performs hosting capacity analysis. Step 5 - DRIVE Connect automatically returns the results to PowerClerk.

DRIVE Connect automates data retrieval for a specific circuit and any other planned DER. It communicates with DRIVE, which then executes hosting capacity analysis for an interconnection, and subsequently post-processes the results. The analysis is fully automated, with results delivered to utility personnel for review and approval. A key point is that the analysis is automated, but the approval is not. It is intended that an engineer or technical staff member review and process the application after the automated analysis is completed. Permission to install or operate the DER is a separate step, but likely reached more quickly if the analysis indicates no hosting capacity limits.

	The goal of the interface (DRIVE Connect) between PowerClerk and DRIVE is to incorporate data and analysis not commonly available early in the screening process, while at the same time increasing processing speed of DER interconnection applications. Additional technical reviews can be manually initiated if applications require more than first-level screening. DRIVE-Connect and similar interfaces can provide a "data bridge" to a range of software tools that provide instructive analytics, notify engineering review, and make technical review more efficient. A first-step in creating a long-term goal for enabling its back-office software systems to exchange data automatically would be to conduct a cost-benefit analysis of such an undertaking. Most LPCs' anticipated interconnection application volume may not yet be sufficient for such an effort to provide a positive net benefit. Still, experience to date with a growing number of utilities located in California, Connecticut, and New York, have found such efforts to be cost effective.
Benefits	Consistency & Quality; Streamline Technical Review
Implementation Outlook	Progression Model Level 5

Recommendation #57 Back to List of Recommendations	**Further develop flexible interconnection agreements to support the greater deployment of grid-connected DER, and pilot a distributed energy resource management system (DERMS) to enable managed control.** ***(Goal)***
Finding/Context	Currently, DER penetration on distribution feeders throughout the Tennessee Valley is generally very low (typically <1% of LPC customers have installed DER), which should allow substantial DER capacity additions to occur in the foreseeable future. However, with projected DER growth, there could be a time when limited available hosting capacity prevents new DER systems from being added to specific feeders. If an LPC begins to approach such a situation, it could consider developing flexible interconnection agreements that enable greater implementation of DER while deferring the need for system upgrades and/or increased distribution system utilization. In tandem, it could consider implementing a communications and control arrangement (such as a Distributed Energy Resource Management System, or DERMS) to manage the safe, reliable, and flexible operation of these distributed assets as required by hourly, daily, and/or seasonal conditions. This latter effort would support an LPC's

	broad operational ambition to integrate a hardware/software platform capable of dynamically controlling the majority of distributed assets on its system. (Note: there are a number of options available for controlling flexible assets, including DERMS as well as local controllers. These options have varying levels of cost, complexity, and functionality.) Increasing grid penetrations of DER are beginning to challenge the accommodation limits of utilities' existing distribution infrastructure in certain locations beyond the Tennessee Valley. Although circuit capacity limits can be expanded, the required system upgrades often add significant costs and delay. In response, "flexible interconnection" approaches are being developed that can increase distribution system utilization and allow more DER to connect and export power to the grid while lowering the cost of integration. These agreements fundamentally include operational restrictions – such as active power curtailment – that limit DER imports and/or exports at key times when and where distribution system constraints are binding. From a control standpoint, autonomous inverter functions following a configurable response profile (e.g., volt-watt, frequency-watt) as defined in IEEE Std 1547-2018 or in the European Network Code Requirements for Generators (RfG), can help defer costly system upgrades at higher DER penetration levels. Managed control is another emerging control approach for real-power management that relies on communications infrastructure and control signals sent by a DERMS-like utility control platform requesting DER units to set or adjust their imports or exports to specific real-power levels, based on grid conditions. If DER penetrations grow in the Tennessee Valley, LPCs and TVA may consider leveraging knowledge accrued from early-adopter utilities that have piloted flexible interconnection agreements in the UK (SP Energy Networks, Northern Powergrid), France (Enedis), and the United States (Avangrid). See *Flexible Interconnection for DER: Emerging Practices at Early-Adopter Utilities* (3002012964). These perspectives can potentially help inform economic and technical approaches (e.g., relevant control techniques) that are well suited for meeting specific objectives under a variety of contexts.

	In preparation for implementation, an LPC may also consider determining both the functions it desires in a DERMS, as well as the standards-compliant downstream (device-level) and upstream (group-level) interfaces that it requires. EPRI's federated architectural view of DERMS is one technical approach that recognizes the relationship between DERMS and DMS and the extension of DER management architectures to include third-party aggregators and decentralized controls. Recent EPRI reporting also discusses both the costs and benefits of DERMS to help utilities consider the merits of a DERMS investment.
Benefits	Enhanced Customer Experience; Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 5

Recommendation #58 Back to List of Recommendations	**Institute integrated distribution planning in the Tennessee Valley.** ***(Goal)***
Finding/Context	Integrated distribution planning (IDP) – implemented by a growing number of U.S. jurisdictions, including Hawaii, California, Minnesota, and New York – offers a pathway for utilities to overcome major interconnection challenges that can hinder the integration of DERs. The overarching approach aims to more broadly help utilities plan their infrastructure investments and manage power quality at the distribution system level in ways that can address DER performance, penetration, hosting capacity, and other issues at least cost. The IDP approach relies on a multi-step process to proactively plan for the integration of DERs into the grid. It involves assessing the physical and operational changes to the grid that are necessary to maintain safety, reliability, and affordability, as well as provide service in a manner that satisfies customers' changing expectations and use of DERs. In short, IDP, in coordination with other types of planning, identifies: 1. Necessary distribution investments to enhance safety, reliability and security, including replacement of aging infrastructure and grid modernization. 2. Changes to interconnection processes and integration investments to support DER adoption. 3. The value of DERs and opportunities to realize net benefits for all customers through the use of DER-provided services. It entails projecting loads and DERs in a more granular way by conducting hosting capacity analyses to determine the amount

	of DERs that can be interconnected without adversely impacting power quality or reliability under existing control and protection systems and without infrastructure upgrades, as well as forecasting the expected growth of DER on evaluated circuits. Other tasks include assessing the locational value of DERs, analyzing non-wires alternatives (NWAs) to traditional investments, accurately representing the distribution system in models for planning and operations, and engaging stakeholders to promote transparency and customer service. By combining these elements, a utility can plan for upgrades in advance, if needed, to accommodate forecasted increased interconnection applications, or potentially identify instances where other DERs can address the expected impacts. Among the steps that can be taken to evolve toward IDP are: • Account for all resources in planning (i.e., consider energy efficiency, demand response – including direct load control, smart thermostats and time-varying pricing, DERs and storage alongside traditional distribution solutions where applicable). • Specify DER attributes to meet identified distribution system needs. • Test new sourcing and pricing methods (e.g., competitive solicitations, tariffs, programs). • Analyze multiple possible futures (e.g., loads, DERs, markets). • Phase in hosting capacity analysis to facilitate DER integration and to indicate relative ease of interconnection at difficult siting locations. • Pilot evaluation of locational impacts to identify where DERs might offer greatest benefits. • Plan integration of utility systems in advance by specifying how any proposed investments (e.g., advanced metering infrastructure, automated distribution management systems, etc.) will be used with other utility assets and systems, and how data will be provided for distribution planning. • Educate and train both internal and external stakeholders.
Benefits	Readiness for Future System Evolution
Implementation Outlook	Progression Model Level 5

Recommendations: IEEE 1547-2018 Readiness

Interconnection & Interoperability Capability (IEEE Std. 1547-2018 Adoption)

Recommendation #59 Back to List of Recommendations	**Determine the adoption timeline of IEEE Std. 1547-2018 (may include a stop gap solution for advanced inverters using UL 1741 SA).** ***(Requirement)***
Finding/Context	TVA and LPCs should determine how soon to adopt new interconnection and interoperability requirements for DER. The default is the adoption of all requirements in IEEE Std. 1547-2018 ("General Adoption"). UL 1741 certification for advanced inverters conforming to IEEE Std. 1547-2018 is picking up the pace and becoming more widely available; some States/Utilities have already started to require projects to use inverters compliant with UL 1741 SB as of Q2 2023. UL 1741 SA provides a stopgap solution for advanced inverter certification until UL certification and equipment conforming to IEEE Std. 1547-2018 become available in the marketplace. With the advent of Flexibility 1.0 contracts, and prospective Flexibility 2.0 contracts, TVA and LPCs should consider adopting the stop-gap measure of using UL 1741 SA inverters if SB inverters are not sufficiently available. Regional DER deployment forecasts and regional bulk system reliability assessments may be needed to justify the need for the UL 1741 SA stop gap solution for assuring that new DER interconnections have ride-through capabilities in a timely manner. Regardless, TVA and the LPCs should ensure that new DER installations are deployed with IEEE Std. 1547-2018 capabilities in a reasonable timeframe (i.e., 3-5 years).
Benefits	Readiness for Future System Evolution
Implementation Outlook	Near term

Recommendation #60 Back to List of Recommendations	**Assign DER abnormal performance categories.** ***(Requirement)***
Finding/Context	Adoption of IEEE Std. 1547-2018 requires the assignment of abnormal performance categories to specific (groups of) DERs, and the coordination of preferred voltage and frequency trip settings across the transmission and distribution (T&D)

interface. The specification of these preferred functional settings will need to balance bulk system reliability and distribution safety concerns. The distribution utility (LPC) should determine these preferred settings in close coordination with TVA (given its role as the Regional Reliability Coordinator).

Decisions related to ride-through capability and trip settings must be addressed in the near-term because the aggregate impact from undesired choices will accumulate over time and a re-configuration could be challenging and costly. The table highlights abnormal performance categories that should be utilized. (More information on these performance categories can be found in EPRI's Generic TIIR.)

Table. Abnormal Performance Categories

Power Conversion	Prime Mover / Energy Source	Category
Inverter	Solar PV, Battery Energy Storage	Category III [1] (amended)
	Wind	Category II
	Hydrogen Fuel Cell	Mutual Agreement
Synchronous generator	Bio-/landfill gas, fossil fuel, hydro, combined heat & power	Category I
Induction generator	Hydro	Mutual Agreement

[1] *Was Category II prior to Amendment*

Source: EPRI's Generic TIIR

Coordination between LPCs and TVA (as the responsible transmission entity, i.e., the Regional Reliability Coordinator) is essential to ensuring that abnormal performance category assignment meets future ride-through capability requirements and voltage trip settings coordinate with regional transmission grid operational and planning practices.

Benefits	Consistency & Quality; Readiness for Future System Evolution
Implementation Outlook	Medium term

Recommendation #61

Back to List of Recommendations

Assign DER normal performance categories. *(Requirement)*

Finding/Context

Adoption of IEEE Std. 1547-2018 requires the assignment of normal performance categories to specific (groups of) DERs (see Table). Category A specifies basic reactive power and voltage regulation capabilities, whereas Category B specifies advanced reactive power and voltage regulation capabilities for high penetrations of variable generation DER. Since voltage-related issues affect primarily the local distribution grid, utilities should be leading the decision making for the assignment of the DER normal performance category but, depending on the regulatory context, may have to work with their respective authorities and stakeholders to make the final assignment. Category A can accommodate synchronous generation-based DER, whereas Category B is applicable for certain inverter-based DER, such as photovoltaic systems.

Table. Normal Performance Categories

Power Conversion	Prime Mover / Energy Source	Category
Inverter	Solar PV, Battery Energy Storage	Category B
	Wind	Category B
	Hydrogen Fuel Cell	Mutual Agreement
Synchronous generator	Bio-/landfill gas, fossil fuel, hydro, combined heat & power	Category A
Induction generator	Hydro	Mutual Agreement

Source: EPRI's Generic TIIR)

Benefits	Consistency & Quality; Readiness for Future System Evolution
Implementation Outlook	Medium term

Recommendation #62

Back to List of Recommendations

Specify a single DER communication protocol, possibly differentiating by DER scale, in conjunction with adopting IEEE Std. 1547-2018. *(Requirement)*

<table>
<tr>
<td>Finding/Context</td>
<td>
<p>The new interoperability requirements for DER include a standardized communications interface and protocol that is locally available at the DER. A standard local DER communication interface makes it possible for the utility (or other parties) to perform monitoring and management/control (changing settings) of DER by deploying an appropriate network when needed, even if a DER vendor has gone out of business. It further allows utilities to collect standardized configuration information, such as nameplate ratings. IEEE Std. 1547-2018 specifies three applicable protocols: IEEE 2030.5 (SEP2), IEEE 1815 (DNP3), or SunSpec Modbus.</p>
<p><u>EPRI Perspective</u></p>
<p>[Recommended] Option A assigns standardized protocols for the local DER communication interface based on identified criteria and could have the benefit of increased interoperability between a DER and the associated DER Gateway that translates the specified local protocol to the protocol used by DER communication networks for integration into DER management systems (DERMS). Option A may not be acceptable to DER owners or developers because it may cause technical barriers for equipment that, although IEEE 1547-2018 compliant, does not use the protocol specified in the Table.</p>
<p>Table - Option A: Assignment of IEEE 1547-2018 local DER communication interface protocols to various types of DERs</p>
<table>
<tr><th>Criteria 1: DER Size</th><th>Criteria 2: Power Conversion</th><th>Examples</th><th>Standardized Protocol</th></tr>
<tr><td rowspan="2">Small scale</td><td>Inverter</td><td>Residential and small commercial Solar PV, Battery Energy Storage</td><td>SunSpec Modbus</td></tr>
<tr><td>Synchronous generator</td><td>Small industrial and independent power producer bio-/landfill gas, fossil fuel, hydro, combined heat & power</td><td>IEEE 1815 (DNP3):AN2018-001</td></tr>
</table>
</td>
</tr>
</table>

Large scale	Inverter	Solar PV, Battery Energy Storage	IEEE 1815 (DNP3):AN2018-001
	Synchronous generator	Industrial and independent power producer bio-/landfill gas, fossil fuel, hydro, combined heat & power	IEEE 1815 (DNP3):AN2018-001

[Alternative] Option B ensures that the DER complies with IEEE 1547-2018 by using one of the three standardized protocols for the local DER communication interface specified in the standard. Option B gives the DER owner or developer a choice which one of the three standardized protocols (listed in the Table) be used and thereby effectively reduces the creation of potential technical barriers.

Table - Option B: Allowing all three eligible IEEE 1547-2018 local DER communication interface protocols

Protocol	Transport	Physical layer
IEEE Std 2030.5 (SEP2)	TCP/IP	Ethernet
IEEE Std 1815 (DNP3):AN2018-001	TCP/IP	Ethernet
SunSpec Modbus	TCP/IP	Ethernet
	N/A	RS-485

Note: Option B should be used if the utility/PUC does not a DER communication roadmap in place. Furthermore, use of DER Gateway with protocol translation functionality can provide flexibility to defer the decision into the future.
Reference: Generic Technical Interconnection and Interoperability Requirements (TIIRs): A Generic Template Including DER Interconnection Technical Review Criteria and Standardized Forms for DER Functional Settings

In the long term, TVA and LPCs should 1) decide what criteria will be used to determine which DER should be

	required to interface with the communications system and when, and 2) select communication networks and architecture.
Benefits	Consistency & Quality; Readiness for Future System Evolution
Implementation Outlook	Medium to Long term

DER Data Management & Functional Settings Determination (IEEE Std. 1547-2018 Adoption)

Recommendation #63 Back to List of Recommendations	**Initiate the collection, management, and maintenance of DER deployment, performance capability, and functional settings data.** ***(Requirement)***
Finding/Context	Adoption of IEEE Std. 1547-2018 should happen in conjunction with DER data collection, management, and maintenance to enable accurate and efficient DER modeling for distribution and transmission planning studies. Information should be collected related to legacy and modern (IEEE Std. 1547-2018 compliant) DERs, including assigned abnormal performance categories to specific (groups of) DERs; preferred, utility-specific, or site-specific voltage and frequency trip settings; as well as active power- and reactive power-related functional settings. Collection of this DER planning dataset by LPCs should commence in the near-term because it becomes difficult to retroactively include planning data from legacy DER. Updated DER planning datasets should be provided by the distribution utility in regular intervals to TVA (as the responsible Transmission Planning Entity and the Regional Reliability Coordinator) for consideration and to maintain coordination with regional transmission grid operational and planning practices (for further details, see recommendations in the Distribution, Transmission, and Stakeholder Coordination section).
Benefits	Consistency & Quality; Readiness for Future System Evolution
Implementation Outlook	Near term

Recommendation #64 Back to List of Recommendations	**IF needed, THEN specify preferred settings.** ***(Requirement)***

Finding/Context	IEEE Std. 1547-2018 provides default values for functional settings for DER performance during normal and abnormal voltage and frequency conditions. If these values are not suitable for the given LPC's jurisdiction, preferred settings should be developed in coordination with TVA and other relevant stakeholders, such as DER vendors, project developers, and customers. Settings should always be within the stated ranges of allowable settings. Example settings include: • *Distribution Hosting Capacity* – Preferred settings for the voltage regulation functions that differ from the default values may increase distribution hosting capacity or better coordinate with existing or planned distribution voltage control schemes. • *Voltage and Frequency Trip* – Preferred voltage and frequency trip settings should be coordinated across the T&D interface. They will need to balance bulk system reliability and distribution safety concerns. The distribution utility (LPC) should determine these preferred settings in coordination with TVA (the Regional Reliability Coordinator).
Benefits	Readiness for Future System Evolution
Implementation Outlook	Near term

Recommendation #65 Back to List of Recommendations	**IF needed, THEN specify utility-specific settings.** ***(Requirement)***
Finding/Context	If the preferred functional settings are not suitable for the utility or for specific DER interconnections in an LPC's service area, utility-specific (service territory-wide) or interconnection-specific settings can be developed in coordination with TVA and other relevant stakeholders. Settings should always be within the ranges of allowable settings stated in IEEE Std. 1547-2018 and should furthermore consider guidance from the Regional Reliability Coordinator, TVA. Example settings include: • *Distribution Hosting Capacity* – Utility-specific or interconnection-specific settings for the voltage regulation functions that differ from the preferred values may further increase distribution hosting

	capacity or coordinate even better with existing or planned distribution voltage control schemes. • *Voltage and Frequency Trip* – Although preferred settings for voltage trip (voltage threshold and/or clearing time) and momentary cessation (voltage threshold) may be applicable for most DER interconnections in a utility's service territory, there could exist specific distribution circuits whose protection schemes differ from the general protection approaches assumed in determining the preferred settings during the Authority Governing Interconnection Requirements' (AGIR's) adoption of IEEE Std. 1547-2018. (Note: in the Tennessee Valley, the LPC Boards are the primary AGIRs, though some responsibilities fall to TVA.) Furthermore, some utilities may want to rely on specific voltage trip settings to coordinate with their particular reclosing practices, while others may employ coordination methods for DER interconnection that are based on historical practices (rather than state-of-the-art). Adjusting the momentary cessation threshold may better coordinate with existing distribution protection schemes and further reduce arc-flash concerns. Site-specific DER trip settings that differ from the preferred or utility-specific settings may be required in a few cases in order to maintain distribution system safety and reliability. As with the establishment of preferred settings, a utility's distribution department will need to coordinate with both the utility's transmission department and the regional reliability coordinator to maintain bulk system reliability, as applicable.
Benefits	Readiness for Future System Evolution
Implementation Outlook	Near term

Distribution, Transmission, and Stakeholder Coordination (IEEE Std. 1547-2018 Adoption)

Recommendation #66 Back to List of Recommendations	**Communicate and coordinate among the multiple Authorities Governing Interconnection Requirements (AGIRs) in the Valley regarding lead times for necessary updates to TIIRs and IA templates, including the need for a stakeholder process.** ***(Requirement)***

Finding/Context	The complexities of adopting IEEE Std. 1547-2018 and the fact that the new standard’s flexibility options (performance categories and functional settings) require some stakeholder involvement, will require the AGIR to get involved at a deeper technical level than in the past. The LPC Boards serve as the principal AGIRs in the Tennessee Valley, though TVA also plays a role and can support creating the broader vision for LPC implementation of IEEE Std. 1547-2018. Experience to date suggests that it can take roughly two years to reach consensus between distribution utilities (e.g., LPCs) and their Regional Reliability Coordinator (e.g., TVA) to assign abnormal (voltage and frequency ride-through) performance categories and to determine preferred voltage and frequency trip setting (thresholds and clearing times). Utilization of new DER communication and interoperability capabilities may require updates to technical interconnection and interoperability requirements (TIIRs) to address customer privacy and contractual concerns. To support the LPCs, TVA should plan to initiate the stakeholder process so that implementation of IEEE Std. 1547-2018 can occur as DERs that are fully certified to comply with the standard become available (some 1547-compliant DER equipment is already commercially available, while many more commercial products are expected to hit the market throughout 2023 and beyond).
Benefits	Readiness for Future System Evolution
Implementation Outlook	Near term

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Recommendation #67 Back to List of Recommendations	**Initiate a stakeholder process to determine interconnection and interoperability capability and, IF needed, THEN also preferred functional settings in advance of (or in conjunction with) adopting IEEE Std. 1547-2018.** ***(Requirement)***
Finding/Context	Adoption of IEEE Std. 1547-2018 requires utilities to make certain decisions about how to implement the standard. These decisions – which include the determination of 1) normal (reactive power / voltage regulation) and 2) abnormal (voltage and frequency ride-through) performance categories, preferred functional (voltage and frequency regulation) settings; as well as the selection of communication protocols – establish the present and future capabilities of new DER interconnections. It is difficult to retrofit new capabilities once these decisions are made. The rationale for making these decisions early on is to

	ensure that new DER interconnections can meet standardized advanced performance and functional capabilities even if some of these may not be utilized until they become necessary at a future date. Regarding functional settings, IEEE Std. 1547-2018 specifies default values. IF stakeholders decide these are not appropriate for certain classes of DER (technology, size, use-case, etc.), THEN preferred settings may be specified for these DER classes. Decisions relating to abnormal performance category assignment and specification of preferred settings for any active power related functions (e.g., frequency-droop [frequency-power] and voltage-active power) should be coordinated with TVA, the Regional Reliability Coordinator.
Benefits	Consistency & Quality; Readiness for Future System Evolution
Implementation Outlook	Near term

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Recommendation #68 Back to List of Recommendations	**Establish protocols/procedures for aggregated data exchange across the T&D interface.** ***(Requirement)***
Finding/Context	Adoption of IEEE Std. 1547-2018 should occur in concert with the establishment of protocols/procedures for the exchange of aggregated data across the T&D interface. This will enable accurate and efficient DER modeling for transmission planning reliability studies. Responsible transmission (TVA) and distribution (LPC) entities should work together to develop, manage, and maintain DER performance and settings databases. Transmission planners are required by NERC to maintain accurate models of system load in their planning studies. Thus, distribution utilities will need to track which DER are designed to meet IEEE 1547-2003 (legacy DER) and which DER are designed to meet IEEE 1547-2018 (modern DER). This applies to both behind-the-meter DER and DER connected to distribution feeders or at the low voltage bus of a substation. Joint EPRI research in the Grid Planning (P40) and Bulk System Integration of Renewable and Distributed Energy Resources (P173) programs has identified DER planning data that need to be collected and exchanged between the

	transmission (TVA) and distribution (LPCs) entities (see deliverables 3002009485, 3002008369, 3002010932). Results from this EPRI research has informed two NERC publications that are publicly available and that specify relevant DER planning data to be collected and exchanged: NERC (2018): *Technical Brief on Data Collection Recommendations for Distributed Energy Resources*. NERC (2017): *Reliability Guideline: Distributed Energy Resource Modeling*. In short, information relating to legacy and modern (IEEE Std. 1547-2018 compliant) DERs – including assigned abnormal performance categories to specific (groups of) DERs, preferred voltage and frequency trip settings, as well as the preferred active power related functional settings for frequency-droop (frequency-power) and voltage-active power – should be collected and exchanged across the T&D interface, at least as aggregated datasets per substation. Collection of this DER planning dataset should commence in the near-term because it becomes difficult to retroactively include planning data from legacy DER. Updated DER planning datasets should be provided by LPCs in regular intervals to TVA for consideration and to maintain coordination with regional transmission grid operational and planning practices.
Benefits	Consistency & Quality; Readiness for Future System Evolution
Implementation Outlook	Near term

Recommendation #69 Back to List of Recommendations	**Initiate development and implementation of internal processes to document and share any non-default DER functional settings (that differ from IEEE Std. 1547 default settings) with DER vendors.** ***(Requirement)***
Finding/Context	As advanced DERs become ubiquitous in new project installations, LPCs, in coordination with TVA, will need to determine whether to require DER settings that deviate from the IEEE Std. 1547-2018 specified default settings in order to best support grid operations and reliability. Prior to the deployment of a communication infrastructure which will allow for the remote updating of DER functional settings, DER vendors will implement manufacturer-automated profiles (MAPs) in their firmware based on utility-required profiles (URPs) specified by LPCs and TVA. Installers/developers

	will, in turn, be empowered to choose from these MAPs, based on the specifics of a DER interconnection agreement. For DER vendors to develop the MAPs, TVA and LPCs must provide their desired URPs to the vendors and establish new processes for doing so. One new process for providing URPs with DER functional settings that differ from IEEE Std. 1547 default settings to DER vendors is to consider developing application program interfaces (APIs) to exchange information with a new DER performance and settings database that DER vendors can access. Consider utilizing the EPRI DER Settings Database, a repository where utilities can upload specific DER settings requirements in the form of Utility Required Profiles (URPs) for public access. Additionally, EPRI has developed a file format specification was developed by a broad set of industry stakeholders to facilitate the communication of these settings and is publicly available here.
Benefits	Readiness for Future System Evolution; Improved Internal Efficiencies; Enhanced Consistency & Quality
Implementation Outlook	Near term

Recommendation #70 Back to List of Recommendations	**IF non-preferred, LPC-specific or site-specific settings for trip or any active power related functions are needed, THEN coordinate with TVA, the Regional Reliability Coordinator.** ***(Requirement)***
Finding/Context	Adoption of IEEE Std. 1547-2018 requires the coordination of voltage and frequency trip settings and frequency-droop (frequency-power) functional settings with TVA, the Regional Reliability Coordinator in the Tennessee Valley. Although not explicitly required in clause 5.4.2 (Voltage-active power mode) of the standard, the preferred settings for that particular function should also balance bulk system reliability and distribution voltage quality and safety concerns. LPCs, in coordination with TVA, should determine the active power-related settings that may need to deviate or are not in scope of the region-wide URP provided by TVA. In such a case, the LPCs should work with TVA to draft their own specific URPs. Utilization of the frequency-droop (frequency-power) function with adequate functional settings must be considered in the near-term. If concerns about the potential impact of that function on unintentional islanding run-on times prevail, adequate settings may impose a wide deadband that effectively

	desensitizes the function's impact. A proportional active power response from DERs to high-frequency conditions (reduction of active power above a certain frequency threshold) has been proven to be of critical importance to maintain bulk system during abnormal frequency conditions—especially those that may occur during system split conditions in an interconnection. The tendency of some distribution utilities to disable this function bears a significant risk that should be avoided by enabling the frequency-droop (frequency-power) functions and choosing adequate settings. Coordination between LPCs and TVA, as the Regional Reliability Coordinator, is essential to ensuring that active power-related settings for the frequency-droop (frequency-power) and voltage-active power functions coordinate reliably with regional transmission grid operational and planning practices. Consider utilizing the EPRI DER Settings Database, a repository where utilities can upload specific DER settings requirements in the form of Utility Required Profiles (URPs) for public access. Additionally, EPRI has developed a file format specification was developed by a broad set of industry stakeholders to facilitate the communication of these settings and is publicly available here.
Benefits	Readiness for Future System Evolution
Implementation Outlook	Near term

Recommendation #71 Back to List of Recommendations	**Initiate stakeholder process to determine future T&D coordination/DER group management functions.** ***(Requirement)***
Finding/Context	The third edition of EPRI's technical update, *Common Functions for DER Group Management*, provides a framework for hierarchical control of DERs in a federated architecture (FADER). Given that future T&D coordination and utilization of the DER group management functions will depend on regulatory and market contexts, a stakeholder process should be initiated to determine their requirements. To this end, it is recommended that TVA, as the regulator in the Tennessee Valley, take the lead in working with LPCs to develop consensus-based T&D coordination priorities that can map to DER group management functions.

Benefits	Readiness for Future System Evolution
Implementation Outlook	Medium term

Recommendation #72 Back to List of Recommendations	**Update TIIRs and IA templates with references to IEEE 1547/.1, UL 1741 SB, and communication certification standards, as applicable.** ***(Requirement)***
Finding/Context	Updating technical interconnection and interoperability requirements (TIIRs) and interconnection agreement (IA) templates is likely to require a stakeholder process. In the Valley, language should be appropriately added/updated in TVA's TIR as well as in each LPC's TIR and IA, and a modification should be made to the Valley-wide IA used in the Green Connect Program (see Recommendation #3). These documents should, as applicable, refer to IEEE Std. 1547-2018 and IEEE 1547.1. For inverter-based DER, reference to UL 1741 SB, which refers to IEEE Std. 1547.1, is applicable. Further references may include communication listing standards like SunSpec, DNP3, and IEEE 2030.5. Updates should consider customer privacy and contractual concerns.
Benefits	Readiness for Future System Evolution
Implementation Outlook	Medium to Long term

Interoperability & Communication Utilization (IEEE Std. 1547-2018 Utilization)

Recommendation #73 Back to List of Recommendations	**Ensure that updates to interconnection agreements allow for utilization of the local DER communication interface.** ***(Requirement)***
Finding/Context	Updates of interconnection agreements that require IEEE Std. 1547-2018 compliant DER should also allow for access to the communication interface and utilization of its features. Utilization of the local DER communication interface can raise customer privacy and contractual concerns that need to be addressed early on. Failure to address this upfront could make meeting the mandate for DER capability difficult to achieve.
Benefits	Readiness for Future System Evolution

Implementation Outlook	Near term

Recommendation #74 Back to List of Recommendations	**Interconnection agreements should include specific technical requirements that bar vendor proprietary “lock/unlock” mechanisms from preventing open access to the DER.** ***(Requirement)***
Finding/Context	Some DER have historically included methods to lockout communication through the local interface, usually with some kind of passcode mechanism. Some vendors may continue this practice even after open standards are required, using a proprietary step to unlock the device before submitting to certification testing, but locking devices that are shipped or installed. The open standard protocols do not support this and cannot unlock a DER that has been locked using proprietary means. Discussion on this topic during IEEE Std. 1547-2018 development left it to the utility interconnection agreements to define what is and is not allowed. Interconnection agreements can address this issue in three primary ways: 1. Do not allow devices to lock out the communication interface. This is the simplest way to ensure future access. It leaves local communication ports open, similar to local keypad interfaces. 2. Allow devices to be locked but specify the messages and passcode(s) by which they are locked so that there is a known, common way to gain access to all DERs in the service territory. 3. Allow devices to be locked in vendor-proprietary ways but require that developers provide documentation to the utility that describes the messages and passcode(s) for each DER. Note: Of the three options, this approach makes integration the most complicated, potentially resulting in large databases of unique passwords and extensive custom software to integrate DERs. TVA’s IA template should include the selected approach, and LPCs should adopt such language in their respective IAs.
Benefits	Readiness for Future System Evolution

Implementation Outlook	Near term

Recommendation #75 Back to List of Recommendations	**Develop a roadmap to guide DER communication and control system deployment.** ***(Requirement)***
Finding/Context	The IEEE Std. 1547-2018 local communication interface enables, but does not require, deployment of a communications and management system. This flexibility allows autonomous operation (set and forget) to be used when/where appropriate and enables each utility to independently determine: 1. When (date) a communication and control system is needed. 2. What technology and performance level of the communication system is required to support their use cases. 3. Which DER types or sizes need to be integrated (a comprehensive DER integration strategy is likely staged). 4. Who will own and operate each level/type of communication integration system (e.g., utility or third party). The development of a communications network can enable versatile settings and control modes to help maintain system reliability. Such a system also aims to serve as a conduit through which DER operating information and eventual settlement for DER-supplied services to the grid can be collected. TVA, in consultation with LPCs, could take the lead in developing such a roadmap, which can support future deployment by LPCs.
Benefits	Readiness for Future System Evolution
Implementation Outlook	Medium term: Roadmap Long term: Deployment

Recommendation #76 Back to List of Recommendations	**IF desired, THEN evaluate and establish processes to integrate DERs into grid operations and markets.** ***(Requirement)***

Finding/Context	Large DER and aggregations of small DER can provide benefits for bulk grid operation through, for example, frequency and var support. Cost-efficient utilization of advanced DER capabilities can create new value streams for DER owners, while maintaining bulk system reliability. However, significant DER integration into grid operations and markets will be challenging prior to the DER communication infrastructure becoming available. FERC Order 841 (Electric Storage Participation in Regional Markets) was established to enable full participation of energy storage in RTO/ISO markets. It allows DERs as small as 100 kW to participate in these markets, thus providing greater opportunity for DER aggregators to compete in providing energy and reliability services. Additionally, in September 2020, FERC approved Order 2222, the final rule that enables DER participation in ISO/RTO markets. The new rule defines a DER aggregator as an entity that aggregates one or more DER that satisfy minimum ISO/RTO performance requirements for purposes of participation in RTO and ISO markets. DERs offer potential benefits for both transmission and distribution grid operations. Consequently, utilities operating both within and outside of organized regional markets should prepare for DER aggregation and management/control. For the Tennessee Valley, TVA could take the lead, in consultation with LPCs, on how aggregated DERs might provide services to TVA's grid operations.
Benefits	Readiness for Future System Evolution; Enhanced Customer Experience
Implementation Outlook	Medium to Long term

Recommendation #77 **Back to List of Recommendations**	**Select communication networks and federated architecture for DER management (FADER).** ***(Requirement)***
Finding/Context	Utilization of IEEE Std. 1547-2018 specified DER interoperability and communications capabilities requires the deployment of communication networks and the specification of the communications architecture. Based on a previously initiated stakeholder process to determine future T&D coordination/DER group management functions (see Recommendation #71

	), LPCs, in collaboration with TVA, should select their communication networks and define how they integrate into the federated architecture for DER (FADER). DERs face a variety of local threats and vulnerabilities which are likely outside of utility responsibility and control. Currently, IEEE 1547-2018 is limited in scope of cybersecurity specification and may only address a subset of security issues. Furthermore, current compliance and certification frameworks are limited in their scope of enforcement to ensure that necessary security controls are adequately met among owners of DER. This presents a challenge for LPCs where assurances in integrity and availability of data and functionalities cannot be fully established. **DER gateways** can serve as local platforms housing features and logics important to the DER managing entity. They also perform several other important functions including translating the DER's communication protocol to the protocol supported by the DERMS and enabling secure integration with utility operations. Security requirements for utility gateways must consider the current deficiencies to help establish trust in the integrity of the DER and to protect critical utility systems, such as DERMS and ADMS, from third-party threats.
Benefits	Readiness for Future System Evolution
Implementation Outlook	Long term

Consideration in Technical Interconnection Review (IEEE Std. 1547-2018 Utilization)

Recommendation #78 Back to List of Recommendations	**Consider new IEEE Std. 1547-2018 voltage regulation capabilities early on in technical review criteria (screenings or study); IF desired, THEN develop methods to specify/implement site-specific settings for advanced DER functions.** ***(Requirement)***

Finding/Context	DER reactive power capability and voltage-related functional capabilities are determined by the IEEE Std. 1547-2018 normal performance category assignment. The autonomous voltage-regulating functions can determine the ability to connect a specific DER to an otherwise technically unsuitable point of interconnection in a given distribution circuit. The goal for LPCs is to develop, in collaboration with TVA, voltage quality-related technical review (screenings or study) criteria to identify those locations where custom settings for voltage-reactive power, active power-reactive power, and constant reactive power modes can be utilized in advanced DER functions (rather than using default values). Such practices are likely to increase the hosting capacity of the distribution system, while maintaining safety and power quality. If desired, methods to specify/implement site-specific settings should be developed.
Benefits	Readiness for Future System Evolution; Enhanced Customer Experience
Implementation Outlook	Near to Medium term, depending on utility preferences

Recommendation #79 Back to List of Recommendations	**IF technical review (screenings or study) indicates a potential risk of inverter-based DER unintentional islanding AND of inverter onboard anti-islanding detection failure, THEN require and use supplemental means of island avoidance or detection.** ***(Requirement)***
Finding/Context	Increased penetration of DER that is able to ride through voltage and frequency disturbances and actively respond to voltage and frequency disturbances may create the prospect that onboard anti-islanding detection methods could fail under certain conditions (e.g., load composition, mix of DER onboard anti-islanding detection methods, etc.). Given that unintentional islanding prevention is a major goal of any DER interconnection, and subject to new research findings, supplemental screenings and full interconnection studies may need updating to reliably determine whether supplemental means of island avoidance or detection are needed. For those DER interconnection requests where “fast track” screenings indicate a potential risk of inverter-based DER unintentional islanding, the distribution utility may require that DER owners disclose the DER’s manufacturer-specified inverter onboard anti-islanding detection method through classification to one or more generic detection method types. This will allow the LPC to perform a more sophisticated supplemental screen or interconnection study. IF the

	subsequent screen or study indicate a potential risk of inverter-based DER unintentional islanding AND of inverter onboard anti-islanding detection failure, THEN require and use supplemental means of island avoidance or detection, such as special protection means like direct transfer trip, to guarantee distribution grid safety and transmission system reliability. Research has shown trends in unintentional islanding detection performance with mixed DER types and has introduced generic detection method types that can be used to classify manufacturer-specified inverter onboard anti-islanding detection methods: Ropp, M.; Mouw, C.; Schutz, D.; Perlenfein, S.; Gonzalez, S.; Ellis, A. (2018), *Unintentional Islanding Detection Performance with Mixed DER Types*. SAND2018-8431. Sandia National Laboratories.
Benefits	Readiness for Future System Evolution; Streamlined Technical Review
Implementation Outlook	Medium term

Recommendation #80 Back to List of Recommendations	**IF distribution circuit and DER data availability and analytical capabilities allow, move away from existing rules-of-thumb.** ***(Requirement)***
Finding/Context	IEEE Std. 1547-2018 requirements provide flexibility in advanced DER settings and functions that can prevent undue impacts on distribution system protection schemes and power quality. For example, the ride-through in Momentary Cessation mode for voltage dips with less than 0.5 p.u. retained voltage, may reduce distribution protection coordination issues. Additionally, the overvoltage creation restrictions, along with adequate test procedures specified in IEEE 1547.1, may reduce the risk of load-rejection overvoltage. Meanwhile, the 15% of peak load rule that aims to prevent unintentional islanding, load-rejection overvoltage, and ground-fault overvoltage may need to be re-evaluated as it may suggest overly conservative results for circuits where any of the following apply: • Long reclosing times; • Grounded circuits; • Minimum load is larger than 30% of peak load; • DER is inverter-based.

	Other substation and/or feeder hosting capacity rules that are based on existing rules of thumb and use fixed aggregate DER feeder/substation thresholds should be replaced with approaches that consider the advanced DER capabilities specified in IEEE Std. 1547-2018, as well as the specific distribution utility feeder reclosing delays used.
Benefits	Readiness for Future System Evolution; Streamlined Technical Review
Implementation Outlook	Medium term

Recommendation #81 Back to List of Recommendations	**Develop technical review criteria (screenings or study) for assessing line worker safety during live-line maintenance on feeders with DER enabled for ride-through voltage disturbances (e.g., arc-flash).** ***(Requirement)***
Finding/Context	Maintaining distribution line worker safety remains a top priority for LPCs; however, the ability of advanced DERs to feed a current during low-voltage ride-through potentially increases the risk of physical harm to line workers from arc-flash incidents during live-line (a.k.a. hot-line) maintenance (e.g., from heat exposure or falling off operating equipment). This is particularly true for utility-scale DER that have a grounding transformer or use step-up transformers which provide a ground source to the Area EPS. As such, extension of the arcing time of faults during live-line maintenance may be perceived as a concern on some line configurations, unless DERs are preventively tripped by distribution system operators. IEEE Std. 1547-2018 allows the utility to require and operate an isolation device or send a shut off to the DER via SCADA prior to maintenance. The standard also permits the utility (or LPC in the Valley) to temporarily and selectively adjust voltage and frequency trip settings outside the specified ranges of allowable settings, but requires such changes to be coordinated with TVA (the Regional Reliability Coordinator). Screening for conditions (e.g., grounding schemes) where 1) arc energy may exceed a defined threshold for faults and 2) the current contribution from inverter-based DERs is the same order of magnitude as the grid contribution, would determine

	the relative risk of arc-flash hazard to live-line maintenance workers and should be considered in personal protective equipment (PPE) guidelines. For synchronous generator-based DERs, overcurrent protection or direct transfer trip can minimize DER fault contribution. More broadly, given that arc-flash is not uniquely related to fault ride-through of DERs, it is worth considering a rewrite of line work practices to address the larger threat of arc-flash to line workers beyond circumstances involving advanced DER facilities.
Benefits	Readiness for Future System Evolution; Streamlined Technical Review
Implementation Outlook	Medium term

Recommendation #82 Back to List of Recommendations	**Consider adopting the IEEE Std. 1547-2018 framework for DER facility design and as-built evaluations, as well as implementing detailed verification procedures beyond those specified in the anticipated IEEE P1547.1.** ***(Requirement)***
Finding/Context	Clause 11 of IEEE Std. 1547-2018 provides guidance on how to verify that DER facilities – either as certified DER systems or as composite DER with partially-certified DER units and supplemental DER devices – fully meet the IEEE Std. 1547-2018 interconnection and interoperability performance requirements at the reference point of applicability (RPA). The RPA is either the Point of DER Connection, the Point of Common Coupling, or any point in between as mutually agreed to between the distribution utility and the DER owner/operator. However, due to lack of mandatory verification requirements in IEEE Std. 1547-2018 and 1547.1, large and small DERs are expected to be interconnected to the grid with inconsistent evaluation of whether 1) the DER facility has been fully assessed and verified prior to commissioning, 2) whether equipment proposed in the screenings is the actual equipment incorporated in the project, and 3) if functional settings have been properly implemented before commissioning. Utilities, including LPCs, and DER developers are expected to both benefit from adopting the new IEEE Std. 1547-2018 DER facility design and as-built evaluations framework specified in Clause 11. This framework can provide a more complete evaluation and verification of the DER facility as well as avoid

	potentially time-consuming and costly modification to DER interconnection during final testing and commissioning. LPCs should consider adopting this new verification framework beyond the DER equipment type and production test procedures specified in IEEE Std. 1547-2018 and IEEE P1547.1. Furthermore, they should coordinate with TVA to enable greater awareness. For more information on current inverter-based resources verification, please refer to: • P2800.2 website at https://sagroups.ieee.org/2800-2/Verifying Performance of Bulk Power-System-Connected Solar, Wind, and Storage Plants at 3002025832
Benefits	Technical Review; Consistency and Quality; Readiness for Future System Evolution
Implementation Outlook	Medium term