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March 25, 2025

Via E-Filing

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Re: Petition of PPL Electric Utilities Corporation for Approval of its Second Distributed Energy Resources Management Plan, Docket No. P-2024-3049223

Dear Secretary Chiavetta:

Please find attached for filing the public version of the Joint Solar Parties' Main Brief.

The **HIGHLY CONFIDENTIAL** version will be filed with the Commission using its Confidential ShareFile site and will only be served upon Administrative Law Judge John M. Coogan and counsel who have executed and returned appropriate Non-Disclosure Certificates pursuant to an appropriate Stipulated Protective Agreement or the Protective Order entered in this proceeding.

Copies will be provided as indicated on the Certificate of Service.

If you have any questions, please contact me at (202) 213-1672.

Respectfully submitted,

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Attachment

cc: Service List
Hon. John Coogan

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a true copy of the foregoing upon the parties listed below via electronic mail and/or hand-delivery, in accordance with the requirements of 52 Pa. Code § 154 (relating to service by a party):

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Dated this 25th day of March, 2025   /s/ Bernice I. Corman

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of PPL Electric Utilities Corporation for Approval of its Second Distributed Energy Resources Management Plan	:	Docket No. P-2024-3049223

MAIN BRIEF OF JOINT SOLAR PARTIES

Before Administrative Law Judge John M. Coogan

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March 25, 2024

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Court Cases

Commission Cases

Statutes and Regulations

I. INTRODUCTION

Pursuant to the February 13, 2025 Briefing Order issued by Your Honor in this matter ("Briefing Order"), ¶ 1, American Home Contractors, Inc. ("AHC"), Enphase Energy, Inc. ("Enphase"), the Solar Energy Industries Association ("SEIA"), SolarEdge Technologies, Inc. ("SolarEdge"), Sun Directed, Tesla, Inc. ("Tesla") and Trinity Solar, LLC ("Trinity Solar" or "Trinity") (collectively, the "Joint Solar Parties" or "JSPs"), by and through their undersigned counsel, respectfully submit their Main Brief in Opposition to the May 20, 2024 Petition filed by PPL Electric Utilities Corporation ("PPL") for Approval of its Second Distributed Energy Resources ("DER") Management Plan ("Second DER Management Plan" or "Second Plan") ("Petition" or "PPL Petition").

a. Description of the Joint Solar Parties

The JSPs are an ad hoc group of entities as follows, all of whom are in the business of installing solar energy and battery storage equipment, manufacturing said equipment, or providing grid services via aggregation of said equipment, or are a trade association representing same, have been impacted by PPL's Pilot Program (also referred to as PPL's First DER Management Plan, and will be impacted if PPL's Second DER Management Plan is approved as proposed:

- SEIA is the national trade association for the solar and storage industries, with more than 1,200 member companies, including most of the JSPs, and other partners who do business in Pennsylvania, including in PPL territory. Joint Solar Parties Statement ("JSP St.") 1, p. 1.
- AHC is a $30 million/year company that presently does business in nine states, including Pennsylvania, and is finalizing its involvement in a tenth state. JSP St. 2, p. 1.
- Sun Directed, founded 16 years ago and employing 11 in Pennsylvania, JSP St. 3, p. 2, has installed 400+ solar and solar+storage projects in Central Pennsylvania. JSP St. 3, p. 1.

• Trinity is one of the largest, independently owned solar installation companies in the United States, JSP St. No. 5, p. 2, that over the last 30 years, has provided solar power and roofing solutions to more than 100,000 homeowners in the mid-Atlantic and Northeast, including 12,000 solar or solar + storage systems in Pennsylvania, over 1,700 of which in 2023 alone were in PPL territory. JSP St. No. 5, p. 2.

• Green Way Solar is not a JSP member but filed initial and Surrebuttal testimony on the JSPs' behalf, due to its dissatisfaction with PPLs' Pilot Program. JSP St. No. 10, p. 2. Green Way has been installing solar systems on residences and businesses in central and eastern Pennsylvania since 2018. Roughly 60% of its projects are in PPL territory. *Id*.

• Tesla is a manufacturer and installer of battery energy storage and solar systems, and is a leading aggregator of residential battery energy storage systems and facilitates customers being compensated for grid services such as generation capacity and ancillary services. Tesla has installed roughly 453,000 residential solar systems across the U.S. with project designs similar to those discussed in this proceeding before it ceased doing new business in PPL territory. JSP St. No. 4, p. 17. As of December, 2023, Tesla or third parties had installed nearly 800 Powerwall battery energy storage units in PPL territory. JSP St. No. 8, p. 3. Over 95,000 Tesla Powerwall residential battery energy systems amounting to more than 500 MW of nameplate capacity are enrolled in more than 50 Virtual Power Plants ("VPPs"), including utility-level programs, as well as aggregations participating in wholesale electricity markets. *Id*. at 5.

• Enphase is a global energy technology company and leading manufacturer of solar microinverters, battery energy storage, electric vehicle supply equipment and home energy management systems that optimize the use of locally produced solar energy to power homes and provide grid services. JSP St. No. 6, p. 2. Enphase also provides third-party aggregator grid services in demand response and VPP programs across the United States and in Europe, working with utilities, grid operators, third party DERMS providers, retail electric providers and homeowners to help utilities and retailers avoid the need to purchase power, in exchange for providing customers compensation that offsets the costs of their DER purchases or reflects the customers' performance in grid services events. JSP St. No. 6, pp. 19 - 20.

- SolarEdge is a Delaware corporation registered to do business in Pennsylvania with headquarters in Israel. SolarEdge is also an aggregator, providing grid services in exchange for compensation, such as generation, demand response, ancillary services, balancing services, voltage or frequency regulation, or other services, in response to utility-level signals or in response to wholesale electricity market opportunities. JSP St. No. 7, p 16.

b. Procedural History

On May 20, 2024, PPL filed its Petition requesting that the Pennsylvania Public Utility Commission ("Commission") approve tariff modifications and other authorizations needed to implement PPL's Second DER Management Plan pursuant to Paragraph 62 of the Joint Petition for Settlement of All Issues approved by the Commission at Docket No. P-2019-3010128. PPL served same on counsel for AHC, SEIA, Tesla and Sunrun, Inc. ("Sunrun"), a group of entities then also referred to as "Joint Solar Parties" in Docket No. P-2019-3010128.

On July 8, 2024, the entities referred to as "Joint Solar Parties" in this docket -- AHC, SEIA, Tesla, Enphase, SolarEdge, Sun Directed, Trinity, and Sunnova, Inc., filed an Answer, Protest, and Petition to Intervene in this docket, the latter of which was granted on August 6, 2024. Sunnova withdrew from this proceeding on July 10, 2024.[1]

c. Concise Statement of the Case

[1] Briefing Order, pp. 1, 2.

PPL's proposed Second DER Management Plan, if approved, would require in perpetuity,[2] as a condition of PPL's granting permission to interconnect to its distribution system,[3] that all DERs[4] owned by customers or third parties[5] interconnected to PPL's distribution system prospectively and retroactively[6] use only a Smart Inverter[7] approved by PPL as meeting state-wide requirements for interconnecting DERs,[8] as well as PPL's bespoke testing requirements to "... ensure that [the inverters] are compatible with PPL Electric's DER Management Devices ...[.]"[9, 10] PPL's program would also require that DER owners allow PPL to install a DER Management Device in their inverters that PPL would use to actively monitor and control their inverters.[11] Participation by all DERs, the majority of which are residential,[12] would be mandatory,[13] and DER owners would not be compensated for the grid services their DERs provide[14] for, effectively, monopoly use by PPL.[15]

[2] PPL St. No. 1, p. 23 (PPL's Second Plan would "make the Pilot Program permanent.")
[3] *See* PPL's Proposed Tariff, Section B (PPL Electric Exhibit (hereinafter "PPL Ex.") SS-2).
[4] DERs are defined as including "inverter-based alternative energy sources and systems, as defined in the Alternative Energy Portfolio Standards Act of 2004 (73 P.S. §§ 1648.1 – 1648.8), and storage resource (batteries)."
[5] PPL St. No. 1, p. 15.
[6] *See Id*. *See also* PPL Ex. SS-2, Sections B., C. (3), ¶ 2.
[7] "Smart inverters" convert the direct current ("DC") power produced by solar panels into the alternating current ("AC") power transported on the electric distribution system for use in homes and businesses. A "smart inverter" is an "inverter that performs functions that, when activated, can autonomously contribute to grid support during excursions from normal operating voltage and frequency system conditions by providing dynamic reactive/real power support voltage and frequency ride-through, ramp rate controls, communication systems with ability to accept external commands and other functions." PPL St. No. 1, p. 24.
[8] 52 Pa. Code § 75.22 defines a Certified DER as having "a designation that the interconnection equipment to be used by a customer-generator complies with the following standards as applicable: (i) IEEE Standard 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems," as amended and supplemented. (ii) UL Standard 1741, "Inverters, Converters and Controllers for use in Independent Power Systems" (January 2001), as amended and supplemented."
[9] PPL Ex. SS-1, p. 7.
[10] The current version of PPL's Approved Smart Inverter List was filed by PPL as PPL Ex. AD-1R, and is available here: PPL Approved Inverter List.
[11] PPL Ex. SS-2, Section D ("…the Company shall be permitted to actively monitor and manage the grid support functions of DER inverters…")
[12] *See* PPL St. 10-R at 10 (99% of systems representing 51% of installed capacity, are below 200-kW).
[13] PPL St. No. 1-R, p. 17 (…"reli[ance] on voluntary participation by a self-selecting group of customers to respond to price incentives will likely not achieve the goals of the Second DER Management Plan…").
[14] *See*, *Id*., and p. 25.
[15] *See*, *infra*, explaining that PPL's physical occupation of the DER's communications port and/or its tariff requirement that DER control cede to PPL, blocks or significantly impedes third parties' ability to participate in providing DER-generated grid services to the PPL or the wholesale market.

The Joint Solar Parties oppose PPL's one-size-fits-all, mandatory, territory-wide, active utility control program in which the utility takes the grid services provided by DERs without compensation[16] because it has driven up the price of solar, increased the cost of installing and servicing solar, blocked or limited the entry of solar and storage products into PPL, and blocked or deterred competition by grid service providers; because it is not necessary now, given the low rate of solar in PPL; because its benefits do not justify its costs; because it exceeds Pennsylvania standards; because PPL's Device disrupts customers' communications and power generation; and because PPL's Device installation has violated the National Electric Code in at least 8,000 systems, caused thermal damage, and voided customers' warranties.

d. Legal Standards

66 Pa. C.S. § 1301 requires that every rate made or demanded by a public utility shall be just, reasonable, non-discriminatory, and in conformity with the regulations or orders of the Commission. *See Metro. Edison Co. v. Pa.PUC*, 22 A.3d 353, 372 (Pa. Commw. Ct. 2011), *cert. denied*, 568 U.S. 959 (U.S. 2012) ("*Metro. Edison*"), *and Lloyd v. Pa.PUC*, 904 A.2d 1010, 1021 (Pa. Commw. Ct. 2006). 66 Pa. Cons. Stat. § 102 defines a "rate" as including any rules, regulations, practices, classifications, or contracts affecting utility charges. *Id*. at 359 (a public utility's rates include, *inter alia*, every individual charge that utility demands for any service offered, rendered, or furnished by the utility whether received directly or indirectly).

66 Pa. C.S. § 315 places the burden of proof on a public utility to establish the reasonableness of its rates. *Metro. Edison*, 22 A.2d 359. While the burden of production may shift, the burden of proof remains on the utility to establish the justness and reasonableness of every component of its rate request and this burden is an affirmative one. *Berner v. Pennsylvania Public Utility*

[16] PPL St. No. 1, p. 10.

Commission, 382 Pa. 622, 631, 116 A.2d 738, 744 (1955). The public utility must satisfy this burden by a preponderance of the evidence. *Energy Conservation Council of Pa. v. PUC*, 996 A.2d 465, 478 (Pa. Cmwlth. 2010). A preponderance of the evidence is established by presenting evidence that is more convincing, by even the smallest amount, than that presented by the other parties to the case. *Se-Ling Hosiery, Inc. v. Margulies*, 364 Pa. 45, 70 A.2d 854 (1950). Additionally, this Commission's decision must be supported by substantial evidence in the record. More is required than a mere trace of evidence or a suspicion of the existence of a fact sought to be established. *Norfolk & Western Ry. Co. v. Pa. PUC*, 489 Pa. 109, 413 A.2d 1037 (1980).

II. SUMMARY OF ARGUMENT

The JSPs strongly oppose a one-size-fits-all, mandatory, territory-wide, anti-competitive, active utility control program that provides no compensation to DER customers (PPL St. No. 1, p. 10), the only program of its kind in the country. PPL's restrictions on inverters fail to meet the just, reasonable and non-discriminatory standard, as they block manufacturers' entry into the market, block third parties' ability to perform the same grid services PPL is performing in a more cost-effective manner, deprive customers of the value of their DERs, as well as the opportunity to choose whether and how they wish to deploy their property towards contributing to grid improvements, and drive up the costs of purchasing, installing, and servicing solar systems.

PPL's program also fails to conform with Commission regulations or orders, as its restrictions on inverters exceed the standards imposed nationally (through IEEE 1547-2018), and state-wide (by 52 Pa. Code § 75.22), and its manner of installing its Devices violates the National Electrical Code, made applicable by 34 Pa. Code § 39.191, in addition to damaging customers' inverters and voiding customers' warranties.

PPL's program is inconsistent with Commission regulations and orders (discussed, *infra*), as it will suppress competition, threaten DER owners' due process rights to interconnect, deprive manufacturers of equal protection, stifle innovation, and deprive ratepayers' ability to choose.

PPL has failed to provide adequate justification for approval of its program at this time, as its territory has very low rates of solar penetration. More to the point, PPL has failed to provide an adequate factual basis demonstrating that the cost of its draconian, unnecessary and expensive program ($81 million through 2030), when weighed against the harms it has inflicted and will inflict on the JSPs, their customers, and the public at large, will outweigh its benefits at any point in time, rendering a decision to approve it unsupportable.

In Docket No. L-2023-3044115, *Distributed Energy Resources Participation in Wholesale Markets*, in its February 22, 2024 Advance Notice of Proposed Rulemaking Order ("ANOPR"), the Commission invited comment on many of the same issues raised in this docket, including on the trade-offs between "allow[ing] for utility direct control and overrides;" the opportunities provided by other options, such as "an option for firm and non-firm approval categories to reduce the need for system upgrades;" and the potential for conflict when utilities and third parties both seek to perform aggregation services in the wholesales market.

The JSPs urge the Commission to resolve these policy questions in its ANOPR docket, or when a better fact pattern and more complete record are presented to it than the one PPL offered in this docket. At a minimum, the JSPs urge the Commission not to approve PPL's Petition as doing so in this docket will deter the dispersal of the very business models envisioned in the ANOPR.

III. ARGUMENT

a. Details of PPL's Program

In Docket No. P-2019-3010128, PPL obtained approval to conduct a three-year Pilot Program (PPL St. No. 7, p. 4) through March 21, 2025. By Order dated September 12, 2024, its term was extended until thirty days after the Final Order is entered in this docket.

As of January 1, 2021, PPL's Pilot Program required that new DERs interconnecting with PPL's distribution system use smart inverters installed in the customer's DER and approved by PPL as meeting UL 1741 Supplement A ("SA"); and PPL's testing for the communications requirements under IEEE 1547-2018 (the "Interim Requirements") – which requirements PPL obtained approval to "proactively implement" in anticipation of UL 1741 Supplement B ("SB") becoming effective. PPL St. No. 1, p. 8.

Since January 1, 2023, PPL's Pilot Program has required that new DERs interconnecting with PPL's distribution system use smart inverters approved by PPL as meeting IEEE 1547-2018, and certified to UL 1741 SB using IEEE 1547.1-2020, PPL St. No. 1, p. 12, and meet PPL's DER Lab's testing requirements "to ensure that [the inverters] are compatible with PPL Electric's DER Management Devices …" PPL Ex. SS-1, p. 7.

IEEE 1547-2018, a consensus-based standard developed by the Institute of Electrical and Electronics Engineers ("IEEE"), provides the technical specifications for interconnection and interoperability between DERs and utility electric distribution grids. JSP St. No. 9, p. 4; 1547-2018 Abstract (attached as Appendix B). Per its Abstract, IEEE 15471-2018's purpose is as follows:

> There is a critical need to have a single document of consensus standard technical requirements for DER interconnection rather than having to conform to numerous local practices and guidelines. This standard addresses that critical need by providing uniform criteria and requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection."

IEEE 1547-2018 Sec. 3.1, defines "interoperability" as "[t]he capability of two or more networks, systems, devices, applications, or components to externally exchange and readily use information securely and effectively." A plain reading of this makes clear that the standard does not specify that networks, systems, devices, applications or components that are certified as being capable of exchanging and using information always be employed by the utility in that fashion.

IEEE 1547.1-2020[17] provides the nationally applicable testing requirements for how DER systems or equipment conform to the requirements of 1547-2018.[18] JSP St. No. 9, p. 4.

UL 1741 Supplement B ("SB") (approved March 5, 2020) provides the official industry standard for Nationally Recognized Testing Labs ("NRTLs'") to verify that the inverter meets the interoperability conformance test procedures set forth in IEEE 1547.1-2020 (approved March 5, 2020) (PPL St. No. 4, p. 6). A NRTL is "recognized [by the U.S. Department of Labor's Occupational Safety and Health Administration ("OSHA")] as meeting the requirements in 29 C.F.R. 1910.7 to perform testing and certification of products using consensus-based test standards."[19] *See also* 52 Pa. Code § 75.22 (similarly defining a NRTL).

Per UL 1741 SB (SB4.3.6.1), the interoperability conformance tests can be met through use of several communications protocols, which are used to store or send information and to control adjustable inverter functions:[20] either IEEE 2030.5,[21] SunSpec Modbus,[22] or DNP3.[23] JSP St. No. 9, p. 4. However, IEEE 1547.1 does not reference any requirement to receive certification by any of these protocol developers, such as SunSpec Certified™, or to any developer-produced test protocols, such as the SunSpec Modbus Conformance Test Procedures.

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[17] IEEE 1547.1-2020 contains IEEE's Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces.

[18] *See,* JSP St. No. 9, p. 4. *See also* IEEE 1547-2018 Abstract states: "The technical specifications for, and testing of, the interconnection and interoperability between utility electric power systems (EPSs) and distributed energy resources (DERs) are the focus of this standard. It provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection." *See*, Appendix B, PDF, p. 3.

[19] *See* https://www.osha.gov/nationally-recognized-testing-laboratory-program/frequently-asked-questions#employers_regulators.

[20] *See* https://solarbuildermag.com/inverters/smart-pv-inverter-overview-ieee-1547-2018-and-ul-1741-explained/.

[21] IEEE 2030.5 provides support for monitoring and control of DER devices. The standard defines the mechanisms for exchanging application messages, the exact messages exchanged including error messages, and the security features used to protect the application messages. IEEE 1547-2018, Annex 2, Clause D.3.2

[22] The SunSpec Alliance specifies standard Modbus-based information to support monitoring and control of the DER devices. IEEE 1547-2018, Annex 2, Clause D.3.4.

[23] IEEE 1815 is used to interface to DER devices, often used by utility supervisory control and data acquisition ("SCADA") systems. IEEE 1547-2018 Annex 2, Clause D.3.3.

That an inverter is "suitable" for use is evidenced by its "listing" or "labeling," 29 C.F.R. § 1910.303(b)(1)(i), which involves inspection and approval by the NRTL using "appropriate test standards approved by OSHA." 29 C.F.R. § 1910.399; 1910.7(b)(1)(i), (c). *Mut. Ins. Co. of Am. v. Royal Appliance Mfg. Co.*, 112 Fed. Appx. 386 (6th Cir. 2004).

PPL's Devices contain an Advanced Metering Infrastructure ("AMI") radio, or cellular modem, that connects to the DER's local communication interface and enables PPL's monitoring and management of the DER. PPL Ex. SS-1, p. 7. A local DER communication interface is "a local interface capable of communicating to support the information exchange requirements specified in this standard for all applicable functions that are supported in the DER."[24] IEEE 1547-2018 defines an interface as "[a]n electrical or logical connection from one entity to another that supports one or more energy or data flows implemented with one or more power or data links." A plain reading of IEEE 1547-2018 makes clear that the standard does not specify with whom or what a local interface must be capable of connecting, nor does it require that the capability to communicate means that the interface must always be employed for communication, nor does it limit the number of local interfaces capable of communicating. Rather, the standard's language ("a local interface") can fairly be read as requiring "at least one" location but prescribes no limits on the number of interfaces.

PPL's DER Lab testing "to ensure that [the inverters] are compatible with PPL Electric's DER Management Devices …"involves PPL's " ... DER Lab verif[ying that] the inverter has the ability to read and write to the Modbus registers or via the 2030.5 interface, an open and available port, and the ability to monitor and manage the DER regardless of the number of inverters networked." PPL St. No. 2-R, p. 19.

[24] IEEE 1547-2018, Section 3.1.

PPL concedes its DER Lab is not a NRTL. Hrg. Tr., pp. 362 – 363.

b. PPL's Program Unlawfully Exceeds Pennsylvania's Standards

The Commission should decline to approve PPL's program, as it unreasonably and unlawfully exceeds Pennsylvania's standards.

i. PPL's Testing Requirements Exceed Those of IEEE and UL

52 Pa. Code § 75.22 requires interconnecting DERs to be certified to meet "(i) IEEE Standard 1547, 'standard for Interconnecting Distributed Resources with Electric Power Systems,' as amended and supplemented," and "(ii) UL Standard 1741, 'Inverters, Converters and Controllers for use in Independent Power Systems' (January, 2011), as amended and supplemented."

PPL's program exceeds Pennsylvania's requirements in several important ways, and in so doing, unlawfully deprives manufacturers and customers of constitutionally guaranteed rights, and usurps the role of this Commission, and unjustifiably discriminates against certain manufacturers and the customers and installers who would choose their products.

First, PPL's program requires that in addition to meeting the above-stated state-wide requirements, that DERs also meet PPL's DER Lab testing requirements "to ensure that [the inverters] are compatible with PPL Electric's DER Management Devices ... " (PPL St. No. 2-R, p. 19; PPL Ex. AD-7), in short that inverters meet IEEE 1547's interoperability requirements. *See* PPL St. No. 4, p. 15; PPL St. No. 6, p. 16. As even PPL's experts admit, no other utility in the country has "taken the next step of leveraging" IEEE 1547-2018's interoperability requirements "to monitor and manage DERs across the distribution system." PPL St. No. 6, p. 16.

However, the Electric Power Research Institute ("EPRI"), as well as industry experts including PPL, have identified 26 gaps in the "interoperability" portion of IEEE 1547-2018. (JSP St. No. 9, pp. 6-7). Indeed, PPL takes credit for having identified some or all these gaps to EPRI, which gaps

PPL discovered when it was testing inverters in its DER Lab for compatibility with its Device.[25]

As a practical result, though, and as PPL and its experts concede (*see* PPL St. No. 2-R, p. 7), the fact of "gaps," or "ambiguities," in the interoperability portion of the IEEE standard means that PPL can be interpreting the standards differently than are the inverter manufacturers or the NRTLs that certified the inverters as meeting the required standards. *See*, *e.g.*, PPL St. No. 5-RJ, p.5. *See also* an article by PPL's Expert, Jay Johnson, stating:

> ... [T]he team unearthed multiple issues with the IEEE 1547.1 test procedure, the information models, pySunSpec2, and the DER simulators running each of the protocols. These issues have been raised with the appropriate companies and committees to address these concerns and streamline the roll-out of advanced inverters.[26]

But PPL is <u>presently</u> excluding or restricting inverters used in its territory,[27] and denying permission to interconnect and permission to operate ("PTO")[28] based upon <u>its</u> unilateral interpretations of interoperability, in advance of the standards committees resolving ambiguities, and to the detriment of certain inverter manufacturers and their purchasers. No other U.S. utility requires that DERs be tested for compatibility with a utility-owned DER Management Device in order to receive approval to interconnect. JSP St. No. 9, p. 6.

As but one example, PPL's program requires that inverters be networked as a condition of being eligible to interconnect. *See* PPL St. No. 2-R, p. 24; Hrg. Tr. p. 342 (where Ms. Dombrowski-Diamond explains that to be approved for use in PPL territory, inverters must "have a network system and be able to communicate to inverters along the chain with a mod ID of two plus").

PPL's webpage containing its "Smart Inverters and DER Pilot Management Requirements"

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[25] PPL St. No. 2-R, p. 7; PPL Electric Exhibit AD-2R

[26] Evaluation of Interoperable Distributed Energy Resources to IEEE 1547.1 Using SunSpec Modbus IEEE 1815, and IEEE 2030.5, IEEE Access, Vol. 9, 2021, p. 142129, 142145.

[27] Hrg. Tr., p. 342, lines 22 – 24; PPL St. No. 2-RJ, p. 37. *See* PPL's Approved List, showing limitations in red font.

[28] *See* Exhibit JSP-JG-3, denying Tesla permission to interconnect multi-inverter solar systems using a Zigbee communications model.

(Updated 2/17/2025) provides:

> Inverter-based DER installations where more than one inverter is installed at a premise require that the inverters are networked together as part of the installation. Inverters shall be networked together such that all applicable inverters can accept commands from the Company-owned DER Management Device connected to a port earmarked and labeled for use by PPL.

Critically, however, IEEE 1547-2018 does <u>not</u> require that inverters be networked as a condition of NRTL certification to the standard.

As discussed above, IEEE 1547-2018 Section 10.1 requires that a DER have provisions for <u>a</u> local interface but does not specify the numbers of interfaces that must be capable of communicating. Further, IEEE 1547-2018, Section 1.4, makes clear the standard does not require that inverters be networked. It states:

> This standard does not determine <u>the communication network specifics</u>, nor <u>the utilization of the DER provisions for a local DER interface capable of communicating</u> (*local DER communication interface*) to support the information exchange requirements specified in this standard.

(emphasis added.).

Finally, IEEE 1547-2018 defines "interoperability" as "a capability which may be met by two or more networks." It does not require that two or more inverters be networked to meet the definition of interoperability.

Notwithstanding the foregoing, PPL has limited the use of 41 inverter models from 6 manufacturers (amounting to nearly one-third of all inverter manufacturers on PPL's approved Smart Inverter List) to single-inverter projects because "those inverters cannot have a network system" and are unable to communicate to other inverters "in a stream." Hrg. Tr., pp. 342 – 343. And PPL has done so, even though each of the inverters was NRTL-certified as meeting the IEEE 1547-2018 standard, as PPL admits. *Id.* *See* PPL Approved Inverter List, on which certain inverters are flagged in red as being limited to "One … Inverter per Application."

Mr. Johnson claims that in June 2024, the above-described ambiguity was resolved with SunSpec's issuance of a certification specification that now requires an adjustable Modbus RTU device address. PPL St. No. 5-RJ, p. 4. But here, Mr. Johnson impeaches himself. He has written:

> IEEE 1547.1 testing is not a comprehensive interoperability test sequence. It is designed to verify a basic level of functionality to demonstrate the DER communication interface is connected appropriately to the electrical control and measurement capabilities of the DER. In order to fully validate the communication capabilities of DER, a separate certification program has been established by the SunSpec Alliance for IEEE 2030.5 clients and servers, SunSpec Modbus devices, and IEEE 1815 masters and out-stations . . . These experiments are <u>not</u> included in the IEEE 1547.1 test procedure."

Disturbingly, when asked about the fact that its interpretation differs from the NRTLs, PPL's response has been consistently to declare that the NRTLs "got it wrong" when they certified inverters as meeting IEEE-1547.1 and UL 1741 SB. *See* Hrg. Tr. p. 369. Or PPL blames the manufacturers. *See*, *e.g.*, PPL St. No. 2-R, p. 16, where Ms. Dombrowski-Diamond stated: "While certain entities may have interpreted those communications protocols incorrectly, which led to the creation of the interoperability gaps ..." *See also Id. at* p. 7 (where Ms. Dombrowski-Diamond blames the manufacturers for interpreting the standards differently "than they are plainly written."). To which the JSPs' expert, Brian Lydic, responded:

> …[The fact that the inverters were able to obtain IEEE 1547-2018 and UL 1741 SB certification by [NRTLs] is evidence that the inverter manufacturers in fact did comply with the requirements under the standard, and that both the NRTL and the inverter manufacturer independently determined that the inverter complied with the standards' requirements. The fact that PPL identified gaps in the standard during its testing is not evidence that the inverter manufacturers have failed to interpret the standards "as they are plainly written" as PPL wishes they were. It also is evidence that PPL is attempting to force inverter manufacturers to a narrow interpretation of the standards that go above and beyond what the standards actually require to achieve certification.

JSP St. No. 9-SR, pp. 4 – 5.

As disturbingly, PPL's expert Mr. Johnson testified that manufacturers can and should expect standards to change – and design to the as-yet unwritten standards. *See* PPL St. No. 5-RJ, p. 4, where he opines: "[i]f DER manufacturer expected their equipment to be placed in a multi-inverter installation, it would be logical to include adjustable device addresses." Mr. Johnson calls on manufacturers to exceed the standards as part of a grand experiment. *See Id*., p. 7, where he states:

> I believe it is most beneficial for utilities to participate in national and international standards-making processes so that gaps can be filled on a wider scale. Over time, revisions to the standards will pave the way to plug-and-play DER environments. However, on a practical level, when an organization is the first to implement a program of this type – as PPL Electric is – there will be clarifications to the standardized interface to get the equipment to operate. Thanks to PPL Electric's work in this area, those clarifications (e.g. support for broadcast mode and support for adjustable device addresses) are now included in the SunSpec specifications.

Id. at p. 8.

PPL and its experts have missed the point of there being standards, and in so doing, are eroding the very uniformity and market certainty that IEEE 1547-2018 is intended to provide.[29] PPL's unilateral gap-filling also undermines the very purpose of NRTL certification (also a cornerstone of Pennsylvania's requirements),[30] which is to ensure IEEE 1547-2018's uniform standards have been met. *See Process Controls Int'l Inc. v. Emerson Process Mgmt.*, 2012 U.S. Dist. LEXIS 151243, *22 - *23 (the value of the certification system rests upon its reliance on testing and oversight by a NRTL).

PPL is not at liberty to disregard manufacturers' NRTL certifications. *See Board Tech Elec. Co. v. Eaton Elec. Holdings LCC*, 2017 U.S. Dist. LEXIS 180348 (S.D.N.Y. 2017), *18, holding:

> It may be that plaintiff's own testing shows that certain of the light switches that bear the UL mark do not in fact comply with the safety standards . . . It is up to United Laboratories to police the mark. To the extent plaintiff believes that the mark has been diluted – or tarnished – by a failure to properly police it by United Laboratories a remedy is available under 15 U.S.C. § 1064(5): plaintiff may seek to cancel the mark.

These issues are not merely academic, as PPL's imposition of its unilateral interpretations is blocking or limiting manufacturers' ability to enter the PPL market, and/or certain inverters or inverter configurations from permission to interconnect, infringing on constitutionally guaranteed

[29] *See*, *supra*, quoting the IEEE 1547-2018 Abstract stating the purpose of the standard.
[30] 52 Pa. Code § 75.22, defining a NRTL.

rights. Certainly, the Commission has taken care in other settings to ensure that novel interpretations of existing standards be subject to notice and comment in a state-wide proceeding.[31]

Further, PPL's reason for discriminating against inverters that cannot network is not justifiable. In *Harris v. Pennsylvania Turnpike Com.*, 410 F.2d 1332, 1336 (3rd. Cir. 1969), the court explained that "…the equal protection clause is offended only if classification rests on grounds wholly irrelevant to the achievement of the state's objective."

Here, however, PPL explains its objective as follows, stating on its FAQ page:

> "**Why does PPL Electric require me to network my inverters?**
>
> As part of our DER Management Pilot Program requirements, PPL Electric is permitted to install a limited number of management devices per calendar year. To prevent the installation of multiple management devices and to keep installations as aesthetically viable as possible, we require networking of all inverters which are part of a single application submission. This allows PPL to expand our Pilot Program to encompass as many of our customers as possible, while at the same time keeping the amount of utility equipment required for your installation to a minimum.

The JSPs submit that PPL is not at liberty to decide that as a cost-savings measure, or worse, due to aesthetic concerns, it is authorized to bar manufacturers and configurations that are certified as standards-compliant from interconnecting based on its unilateral resolution of a standards gap.

And again, the JSPs note that to date, at least 25 additional gaps in the standard have been identified that may be differently interpreted by PPL and manufacturers and NRTLs. *See*, *e.g.*, Proposed Findings of Fact, ¶¶ 41 – 46, 48 – 50.

ii. PPL's Tacit Claim of Exclusivity Over Reactive Power Overreaches

PPL's program exceeds IEEE standards in another important regard. PPL claims that the principal purpose of its program is to increase hosting capacity by "addressing over and under-voltage violations by assuring appropriate levels of reactive power." PPL St. No. 1-R, p. 8. PPL

[31] *See*, *e.g.*, Jan. 13, 2012, , *Standards for Electronic Data Transfer and Exchange Between Electric Distribution Companies and Electric Generation* Suppliers, Pa. PUC Docket No. M-00960890F0015 (Jan. 13, 2012), p. 1.

claims its manipulation of reactive power does not interfere with the JSPs' ability to aggregate grid services because, PPL claims, no market exists for provision of reactive power. *Id.*; PPL St. No. 4-R, p. 20. Indeed, PPL's expert asserts that in his opinion, which he claim "the text and context of IEEE 1547-2018 supports," the appropriate role of an aggregator is the management of DER active power[, while r]eactive power and distribution system voltage management are . . . not commodities appropriate for aggregation." PPL St. No. 4-R, p. 26. PPL claims its management of reactive power has no material impact on the level of real power DERs can produce or export, PPL St. No. 1-R, p. 9, but that "to the extent there is curtail[ment of] active (real) power to produce increased reactive power to meet applicable power quality parameters," PPL St. No. 1-R, p. 18, it is as a result of a discretionary design choice by the inverter manufacturer.

PPL errs in all regards. Firstly, PPL has continually disregarded evidence put forth by the JSPs that they have participated in programs involving their management of customers' reactive power. SolarEdge participated in a utility program in which SolarEdge provided the service of improving power quality by remotely updating customers' reactive power control settings to absorb or generate reactive power when the grid voltage was outside a predefined range. Customers were offered a flat fee for enrolling, more for staying in the program, and additional compensation when SolarEdge's manipulation of the customer's reactive power did in fact interfere with the customer's generation of real power. JSP St. No. 7, pp. 20 – 21; JSP St. No. 7-SR, p. 18; Ex. JB-21SR.

Secondly, PPL misunderstands the implications of its demands that the manufacturer design an inverter large enough to produce sufficient reactive power to meet PPL's needs, as well as the customer's interest in real power. The JSPs' testified that in their experience, a large, commercial customer may spend more on an inverter big enough to meet both. But:

> …[t]o [the JSPs'] knowledge, it is not typical of manufacturers of residential system inverters to design their inverters this way, because it requires inverter manufacturers to oversize the

> inverter's capacity, list the inverter at a lower nameplate capacity, and reserve a portion of the inverter capacity at all times to sit idly until it can be used to provide reactive power.

JSP St. No. 7-SR, p. 21. Doing so "would risk increasing the inverter's price and making it less competitive, especially in the residential market." JSP St. No. 8-SR, pp. 6 – 7.

Importantly, the IEEE standards do not go as far as PPL envisions. The standards do not by themselves authorize utilities to carve up the market, as PPL is proposing in its Second Plan. IEEE 1547 Section 1.4 is explicit that it is the Commission that has the responsibility to determine who shall manage reactive power capability, stating:

> " . . . it is the responsibility of the *authority governing interconnection requirements* (AGIR) to determine the applicability . . . of performance categories related to reactive power capability and voltage regulation performance requirements . . . "

In Section 1.4, n. 12, the standard reinforces the critical role played by the Commission, stating:

> The impact of DER on frequency and voltage performance of the interconnections and the regional power systems differs significantly, and it remains the responsibility of an AGIR to quantify impactful DER penetration levels.

Again, the JSPs urge the Commission to provide heightened scrutiny when examining PPL's claims its program comports with IEEE standards.

iii. PPL's Claims regarding Anti-Island Overreach

In addition to claiming that its program focus is on managing reactive power, PPL argues its control of customers' inverters is required to use remote on/off functions on battery storage or solar systems that have not safely isolated, or "islanded" from the distribution system. Petition, p. 15.

PPL overplays this concern. The sole evidence to which PPLs point as the reason it needs control is an NREL Primer it claims states that "increasing DER penetration and deployments of different types of inverters can increase the likelihood of unintentional islands." PPL St. No. 3, p. 56; D. Narang, et al., NREL/TP-5D00-77782, April, 2022, *A Primer on the Unintentional Islanding Protection Requirement in IEEE Std 1547-2018* ("NREL") (appended).

But NREL's Primer makes clear that discussions on enhancing unintentional islanding risk and prevention may be entertained in future updates to IEEE Std 1547-2018. The Primer also makes clear that NREL's concern arises in "high-penetration" scenarios (NREL, p. 22), which, as explained, are at least ten years away in PPL's territory. Consistent with NREL's finding, OCA's expert noted that Australia's Energy Management Office needed the ability to turn off solar in rare emergency conditions in an area where rooftop solar is periodically applying more than 100% of the state's demand. OCA St. No. 1-SR, pp. 10-11. PPL simply does not have that need at this time.

Indeed, PPL's expert's own testimony underscores the lack of a present-day need for PPL to have active remote access to inverters' on/off function. Mr. Davis testified that to date, PPL has "not yet" accessed the remote on/off capability it gave itself. Mr. Davis explained the reason PPL had not yet done so was because out of the numerous outage events PPL observed that impacted actively managed DERs, none caused an unintentional islanding event. PPL St. No. 3, p. 55.

The JSPs agree that DERs must have effective anti-islanding capabilities. However, as the Commission has noted, that anti-islanding capability is already built into inverter-based systems certified to IEEE 1574 standards and tested in accordance with UL 1741.[32] *See also*, JSP St. No. 14-SR at pp. 15-16, where the JSPs explain why PPL's concern with anti-islanding is not valid.

The JSPs again urge the Commission to exercise care in contemplating sanctioning a program that would <u>exceed</u> IEEE standards, and by definition, those incorporated into Pennsylvania regulations, where there is no present need to do so.

iv. IEEE Calls on the Commission to Decide Questions of Control

Finally, PPL's assertion of "control" in the manner required by PPL's program, is not required

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[32] Pa. PUC, *Final Rulemaking Re Interconnection Standards for Customer-generators pursuant to Section 5 of the Alternative Energy Portfolio Standards Act, 73 P.S. § 1648.5; Implementation of the Alternative Energy Portfolio Standards Act of 2004: Interconnection Standards*, Docket No. L-00050175, p. 9 (Aug. 17, 2006).

by IEEE. Again, 1.4 makes clear that a local DER interface must be capable of communicating, but it does not state that the interface shall be always used by the utility for such purpose.

The standard further states: "it remains in the responsibility of an AGIR to quantify impactful DER penetration levels." 1547-2018, n. 2.

Finally, the standard developers have also made clear that the standard does not prescribe a particular use case, such as the active management and control regime contained in PPL's plan. As the JSPs' expert Brian Lydic testified:

> ... [I]n the … IEEE 1547.2-2023 Guide[,] which provides technical background and guidance to support understanding of IEEE 1547-2018, the guidance explicitly states that: "IEEE Std 1547-2018 does not assume a specific use case or application . . . This standard does not address planning, designing, operating, or maintaining the Area EPS with DER."

In short, it is squarely the responsibility of this Commission to decide whether the levels of penetration seen today warrant the Commission's granting PPL a monopoly over monitoring and management of residential customers' DERs. The JSPs respectfully contend that the record developed by PPL fails to provide the Commission with the foundation with which to do so.

IV. PPL FAILS TO SHOW ITS PROGRAM IS REASONABLE, JUST OR IN THE PUBLIC INTEREST

a. PPL Fails to Show its Extreme Program is Necessary at this Time

PPL claims its Plan will assist it in "proactively preparing for increasing DER interconnections," PPL St. No. 1, p. 28, chiefly, by "increase[ing] hosting capacity for additional DERs at far lower cost than the available alternative."[33] PPL St. No. 1-R, p. 15. PPL also claims its Plan will assist it in "proactively tackling issues presented by DERs, rather than invest in costly distribution system upgrades to resolve those issues." *Id*. at 34.

[33] "Hosting capacity" is the amount of [distributed photovoltaic systems] ("DPV") that can be added to distribution system before control changes or system upgrades are required to safely and reliably integrate additional DPV. Petition, n. 2.

The JSPs applaud PPL's forward thinking and goal of increasing the numbers of solar energy users on its system. However, the JSPs respectfully submit that in seeking to establish a program to resolve problems potentially caused by DERs that PPL admits are not upon us, PPL has failed to provide the Commission with a reasonable basis for it to approve a "proactive" program that is this extreme and this costly at this time, particularly where doing so improperly strays from legal bounds, as discussed herein,[34] and inflicts so many harms (*see*, *infra*, Sec. IV.b.iii.).

First and foremost, PPL has failed to demonstrate why its program, with its first-in-the-nation features, must be approved now. PPL has very low rates of solar penetration (only 3.94% of peak capacity in PPL territory 270.641 MW), as compared with Vermont's (32%), or San Diego's (43%).[35] Accordingly, there is simply no fact-based reason to concur that PPL's program as currently designed is justifiable.[36] This is especially the case, given that PPL's Device has a 15-year book-life,[37] and that DERs installed today that must be compatible with PPL's Device "are expected to remain connected to the PPL Electric System for decades."[38] Approving this program now will deprive Pennsylvanians long into the future of the advances in technologies and approaches that will evolve in this next ten-year period.

Similarly, PPL offers no credible factual bases for its projections of future DER rates. For example, PPL claims a study by Deloitte "shows that by 2035, Pennsylvania <u>would</u> rank sixth amongst all states in DER capacity . . .," PPL St. No. 1-R, p. 47; PPL St. No. 1-RJ, p. 13. (emphasis added.) However, in addition to the study being purely aspirational, the study actually states only

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[34] *See e.g., Sunrise Energy, LLC v. PPL Corp.*, 2015 U.S. Dist. LEXIS 39433, *14 (W. Dist. Pa. 2015) (recognizing the "clearly established right to net meter" under the Alternative Energy Portfolio Standards Act, 73 Pa. Stat. §§ 1648.1-1648.8).
[35] JSP St. No. 1, pp. 10, 19-20.
[36] *Philadelphia Suburban Transp. Co. v. Pennsylvania Public Utility Com.*, 281 A.2d 179 (Pa. Commw. 1971) ("Both at common law and under our statutes, the discrimination forbidden is one that is unreasonable and without factual basis.")
[37] PPL St. No. 10-R, p. 5.
[38] PPL St. No. 4-R, p. 14.

that ". . . residential capacity could grow . . . " by 2035. *Id.* (emphasis added). Similarly, a study cited by PPL's expert, discussed *infra*, assigns an amount of future distributed generation to solar that is 57% lower than the amount he assumes in his analysis. JSP St. No. 4-SR, p. 27.[39]

By contrast, jurisdictions with far higher rates of solar penetration are relying on an array of tools – such as custom smart inverter setting profiles, grid modernization investments, voluntary flexible interconnection options, and compensation for customers and non-utility service providers who both provide and receive grid services – without causing power quality or reliability issues.

For example, Hawaiian Electric is projected to have over 2,086 MW of solar on its system by 2045.[40] Its grid modernization strategy, however, includes the creation of custom smart inverter setting profiles, grid modernization investments, ". . . equitable cost allocation and compensation for customers and other non-utility service providers who both provide and receive grid services." *Id*., p. 9. Notably, even utility programs that have piloted active utility control and shown that such control can provide benefits, PPL St. No. 7-R, p. 5, *citing* JSP St. No. 1, p. 24, have also provided compensation to DER owners for their provision of grid services, have been fully voluntary, and have provided customers with the ability to use software to manage their DERs, rather than having to install a utility-owned management device in their inverters.[41, 42]

PPL, however, has refused to explore whether it could achieve its objectives through a voluntary program, conceding it conducted no analysis as to any specific level of enrollment that could accomplish its program objectives. *See* Ex. JSP-NZ-1SR, PPL's response to an Office of

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[39] *See also*, *infra*, regarding PPL's internal analysis.

[40] Hawaiian Electric, Maui Electric, Hawai'i Electric Light, Modernizing Hawai'i's Grid for Our Customers, August 29, 2017, *available at:* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/grid_modernization/final_august_2017_grid_modernization_strategy.pdf , p. 3 (*cited in* JSP St. No. 1-SR, p. 17).

[41] JSP St. No. 1-SR, p. 5, *citing* Ex. JSP-JW-2SR ("California Energy Commission, Final Project Report, Electric Access System Enhancement, Assessment of a Distributed Energy Resource Management System for Enabling Dynamic Hosting Capacity, June 2024; CEC-500-2024-064), p. 14.

[42] *See* Office of Consumer Affairs ("OCA") St. No. 1, p. 30, *citing* San Diego and Massachusetts' ConnectedSolutions.

Consumer Affairs discovery request acknowledging that PPL did not even seek to identify such level, having found instead "that monitoring and active management have already become desirable and cost-effective and will provide significant benefits."

It is particularly troubling that PPL conducted no analyses into the need for its Second Plan to apply retroactively.

PPL's Pilot Program capped the number of Device installs at 3,000/year, PPL St. No. 1, p. 13, and excluded from Pilot requirements members of control groups whose DER inverters operated instead under autonomous settings only, PPL St. No. 1, p. 14, and members in a Grandfathered Group. PPL St. No. 1, p. 3. However, PPL's Second Plan would apply to all new DERs, to all DER's in the Pilot Program's control groups, to all systems interconnected before the Pilot Program started on January 1, 2021, and to all inverter-based DERs interconnected after the Pilot Program started without Devices installed; and would remove the Pilot Program's 3,000 Devices/year cap. PPL St. No. 1, pp. 22 - 23. Previously excluded customer-generators would be required to submit a new interconnection application when they upgrade their system, install a new inverter on their system, or by March 22, 2040, whichever is earlier. PPL St. No. 1, n. 3

As of the date of its Petition, PPL had 26,243 customer- and third-party -owned DERs on its system, 11,841 of which interconnected during the Pilot Program. PPL St. No, 1, pp. 25, 11. Of the 11,841 customers, 7,418 were included in the program and have a Device installed, while 4,423 DERs were grandfathered because of the annual cap, or because there were no Devices available that were compatible with those DERs at the time of interconnection. PPL St. No. 2, p. 11.

PPL's proposed retroactive reach is unreasonable to customers who invested in very expensive equipment will be subject to utility control they never envisioned when they signed up for net metering. JSP St. No. 1-SR, p. 15. It will also serve to disincentivize those customers from seeking to upgrade their systems. JSP St. No. 2, p. 4.

The law typically frowns upon retroactive application absent "extraordinary and nonrecurring exceptions."[43] Having done zero analyses to support the request be territory-wide and backward-reaching, the JSPs respectfully submit that PPL has failed to meet this steep burden.

PPL has also refused to explore whether provision of compensation to customers would incentivize enrollment in a program. *See*, *e.g.*, PPL St. No. 1R, p. 17, where PPL states without pointing to any factual support, that "relying on voluntary participation by a self-selecting group of customers to respond to price incentives will likely not achieve the goals of the Second DER Management Plan, which require wide deployment of active management to achieve the benefits of the kind and magnitude that [PPL's expert] identified in his cost-benefit analysis."

PPL points to no support for its conclusion that its provision of incentives would not bear fruit. Utilities are experienced in calculating the incentive amount that might be reduced to induce program enrollment. *See e.g.*, *Pennsylvania Public Utility Commission, et al. v. UGI Central Penn Gas, Inc.*, Pa. PUC Docket No. R-2010-2214415, et al. (July 23, 2012). In this docket, however, PPL has elected not to do so.

PPL argues: (i) that "PPL is the owner of the devices and incurs all of the costs associated with the program[, so t]here is no logical reason the DER owners should be compensated for grid benefits created by Company-owned devices[;]" and (ii) that " . . . the current net metering credits provided to DER owners are more than sufficient compensation for the benefits that they provide to the PPL Electric System." PPL St. No. 10-R, p. 36.[44]

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[43] *Application for Authority to Transfer Control of Trigen-Philadelphia Energy Corporation by the Sale of All of its Stock, Currently Owned by Trigen Energy Corporation, to Thermal North America, Inc.*, Docket No. A-130375F5000 (April 7, 2005), p. 20.

[44] PPL's Sal Salet and Bethany Johnson add: (iii) that PPL's increasing hosting capacity will lower costs to PPL and to future DER owners; and (iv) that PPL's program focuses on manipulating reactive power, for which no market exists. PPL St. No. 1-SR, pp. 8-9; PPL St. No. 11-RJ, p. 7. We address these last two arguments, *infra*.

PPL's premises are deeply flawed. As explained by JSP witness Marc Monbouquette -- the reason DER owners should be compensated for the grid services they provide is because it is they who own the DERs that provide the reactive power support functions and monitoring capabilities PPL manages. JSP St. No. 6-SR. If it weren't for customers' DERs, there would be no reactive power for PPL to manage.

Importantly, PPL has acknowledged that the voltage violations for which the DERs are resolving are remote from the point of interconnection and that PPL does not know the root cause of these voltage violations. This means that by definition, the DERs are resolving grid voltage problems for which they are not the cause, which underscores that they are providing a grid service deserving of compensation. *See* JSP St. No. 9, p. 10, and Exhibit JSP-MM-1SR.

While the JSPs do not concede that Pennsylvania's net metering law is even intended to compensate a DER owner for their provision of grid services (as opposed to real power), the JSPs agree with PPL that the law provides for compensation beyond generation, insofar as the "full retail kilowatt hour rate" includes distribution and transmission charges in addition to generation. PPL St. No. 11-R, p. 22. 52 Pa. Code § 75.13. However, again, PPL has made no effort to calculate whether the "excess" it contends DER owners are paid even begins to approach the value of the grid services their DERs can provide, nor the higher prices they will have to pay for equipment over-sized to ensure production of reactive power over and above what they need to meet PPL's reactive power desires. *see* JSP St. No. 7SR, p. 19.

The JSPs' respectfully submit that PPL's failure to even attempt to do so, coupled with its failure to assess the level of sign-up needed to achieve its objectives, especially in light of PPL's proposed retroactive application, fail to provide the Commission with an adequate basis upon which to conclude that PPL's proposed mandatory, compensation-less, highjacking of customers'

DERs is reasonable, just, or in the public interest.

b. PPL Has Failed to Show the Costs of its Program are Reasonable

i. Mr. Wishart's Cost/Benefit Analysis Contains Significant Flaws

The JSPs respectfully submit that PPL has failed to justify the benefits and costs of its program in several significant regards.

First, PPL's cost/benefit analysis is suspect, as it has greatly changed over the course of the proceeding. For example, in its Petition, PPL claimed that through the end of Program Year 2, the Program's greatest single monetary benefit was in avoiding voltage violations. Specifically, PPL claimed in its 2024 DER Management Report that active management of DERs avoided over 23,000 voltage violations that could have resulted in truck rolls, saving over $13.6 million dollars, PPL St. No. 3, p. 48. In its 2024 DER Management Report, PPL claimed that avoided truck rolls produced most program benefits, amounting to roughly 62% of PPL's claimed benefits of its program.[45] In fact, PPL's 2024 DER Management Report found that the benefit from avoided truck rolls alone was more than double the roughly $6.5 million in program costs to date at that time (PPL's calculations show avoided benefits as 2.09 times higher than program costs). *See*, *Id*., p. 1.

However, on Rebuttal, PPL's Expert Witness, Steven Wishart, explains that his "... approach to estimating avoided truck rolls ... result[ed] in a much lower estimate" than the one in PPL's Petition. PPL St. No. 10-R, p. 18. Mr. Wishart estimated 172 avoided truck rolls per every 10,000 DER Management Devices, PPL St. No. 10-R, p. 29, which is roughly 75 times less than what PPL estimated in it 2024 DER Management Report. In fact, Mr. Wishart's analysis reduced the benefits from avoided truck rolls to only 5% of the total program benefits. PPL St. No. 10-R, at 9.

But as the benefits PPL claimed from avoided operations and maintenance expenses shrunk

[45] PPL Ex. CD-4, p. 19 attributes $13.66 million to avoided truck rolls, and p. 1 lists $21.93 in total benefits to date.

significantly from its 2024 DER Management Report to Mr. Wishart's analysis, another type of benefit grew significantly. In its Petition, PPL identified 29 MW of new hosting capacity resulting from monitoring DER production, active management of power factor, and use of smart inverter settings in its Pilot. PPL St. No. 10-R, pp. 15 – 16. If fully utilized, PPL claimed the hosting capacity would have produced additional generation, and reduced distribution and transmission losses valued at approximately $4.57 million, amounting to roughly 21% of the roughly $21.9 million in benefits that PPL claimed under the Pilot. *See*, PPL Ex. CD-4, at p. 1.

However, on Rebuttal, Mr. Wishart identified that 85.9% of the Program's benefits would come from "incremental hosting capacity" created by the program, PPL St. No. 10-R, Table SWW-6, JSP St. No. 4-SR, p. 26, PPL St. No. 1-R, p. 5, PPL St. No. 10-R, p. 9. In total, this means that as PPL's claimed benefits from avoided operational and maintenance costs shrunk by a factor of 12 between the two analyses, PPL's claimed benefits from incremental hosting capacity essentially increased fourfold as a proportion of claimed Program benefits.

By itself, these dramatic differences in analyses (which, the JSPs note, were <u>not</u> presented in PPL's case in chief, as required by 52 Pa. Code § 5.243(e)) call into question the credibility of Mr. Wishart's analysis. But in addition, the JSPs submit that Mr. Wishart's analysis is itself significantly flawed, in particular because it significantly overstates the amount of benefits PPL's program would provide from incremental hosting capacity in several important ways.

First, Mr. Wishart justifies his assumption that all 258 MW of "incremental hosting capacity" will be used based on extremely aggressive DER growth projections – namely, that PPL expects roughly 5,731 MW of solar to be installed between 2025-30, or 11.6 times more over the next six years than has been deployed to date in Pennsylvania. JSP St. No. 4-SR, p. 27 (*citing* PPL's Answer to OCA-II-6).

However, the JSPs' analysis reveals that the two studies upon which Mr. Wishart based these projections do not provide him with the foundation he seeks. The Pennsylvania Department of Environmental Protection's ("PaDEP's") Solar Future Plan, Ex. JSP-JG-13SR, sets a target for the amount of solar PaDEP recommends be achieved by 2030 (10% of energy consumed). It does not provide an actual projection that the Commonwealth will achieve the target. Second, even if the 10% amount were to be achieved, the report states that only 2,500 MW is projected to come from distributed generation -- an amount 57% lower than Mr. Wishart Assumed in his cost/benefit analysis. JSP St. No. 4-SR, p. 27, *citing* Ex. JSP-JG-13SR.

The second study, PPL's internal Draft DER Forecasting Paper lacks credibility, for example, because it lacks definitive territory-wide projections, and fails to account for projections from other solar industry publications. JSP St. No. 4-SR, p. 28. As it is also potentially self-serving (generated by PPL), the Paper fails to provide a solid foundation upon which to premise a projection that is responsible for 89% of the benefits.

However, Mr. Wishart's estimate of the savings attributable to 258 MW of "incremental" hosting capacity is suspect because it contains an even more impactful flaw: as was made clear during the Hearing, Mr. Wishart likely double-counted some or all of the components comprising the benefits he ascribes to the increased "incremental" hosting capacity resulting from the program.

Mr. Wishart estimates that 258 MW of "incremental" hosting capacity will save $61.3 million from "Avoided Distribution Infrastructure Investments" and $64.6 million from "Avoided Energy from Incremental Hosting Capacity." PPL St. No. 10-R, p. 9, Table SWW-2. However, Mr. Wishart acknowledged during the Hearing that a specific DER cannot produce both benefits, essentially acknowledging a double counting of benefits. Hrg. Tr. pp. 212-215.

In the Hearing, Mr. Wishart agreed some homeowners would interconnect DERs regardless of whether PPL's Plan is approved, and that those customers therefore would have paid for grid upgrades to support their interconnecting. Hrg. Tr., p. 213. For these homeowners, it is appropriate to count the benefits attributable to avoided infrastructure investments, because the homeowners would have paid for them. But, as Mr. Wishart agreed, it is inappropriate to count avoided energy costs, because those homeowners' DERs would have interconnected and been generating energy even without PPL's Plan, as Mr. Wishart stated. Hrg. Tr. p. 214, line 15, and p. 216, lines 5 - 8.

Mr. Wishart also agreed that for the homeowners who would <u>not</u> have interconnected their DERs but for the Plan, it is appropriate to count benefits attributable to the avoided costs of purchasing energy for them, but not the benefits associated with avoided infrastructure investments. These customers would not have required upgrades because they wouldn't have interconnected. Mr. Wishart so stated this as well. Hrg. Tr., p. 214, lines 7 – 9.

Importantly, for all DERs that would conceivably interconnect to the 258 MW of incremental hosting capacity that Mr. Wishart claims would be created, each DER falls into only one of these categories: either it would have interconnected regardless of PPL's Program or it would have interconnected only due to PPL's Program. That in turn means that no DER among the 258 MW that Mr. Wishart projects to use the Plan's "incremental hosting capacity" can claim both avoided infrastructure investments and avoided energy costs. However, Mr. Wishart counted both benefit values for all the 258 MW of DERs interconnecting using the "incremental hosting capacity." That is clear evidence of significant double counting, to the tune of between $61.3 million and $64.6 million, rendering Mr. Wishart's projected benefits, again, highly suspect.

Finally, the JSPs submit that Mr. Wishart's analysis overstates benefits to ratepayers, as it fails to distinguish the proportion of the benefits associated with Avoided Distribution Infrastructure Investments that would flow to ratepayers, rather than to the owners of interconnected DERs, given that DER owners typically pay the costs of grid upgrades associated with interconnection. JSP St. No. 4-SR, p. 28; PPL St. No. 10-RJ, p. 22; Hrg. Tr. p. 206. While Mr. Wishart contends that he could not accurately forecast what proportion of the benefits would flow to ratepayers rather than DER owners (*see*, PPL St. No. 10-RJ, at p. 22), the omission of this information leaves the Commission with insufficient information regarding whether any portion of the largest single benefit that Mr. Wishart projects under the Plan would ultimately flow to ratepayers.

When accounting for the numerous flaws in Mr. Wishart's analysis, the JSPs found that the Plan's benefit-to-cost ratio dips significantly. After subtracting the roughly $61.3 million of projected benefits that are clearly double counted by Mr. Wishart (a conservative reduction), the program's benefit-to-cost ratio falls to 1.05 (down from the 1.8 ratio that Mr. Wishart calculated). This means with this simple correction alone, that PPL's Plan would provide only slightly more total benefits than costs. However, importantly, this ratio would hold true only if *all* of Mr. Wishart's other projections also hold true. That means that unless PPL actually sees 11.6 times more DER installed over the next six years compared to the total number of DERs installed in its territory to date, and unless that level of installation actually requires the specific 258 MW of incremental hosting capacity that PPL claims will be created under the Second Plan, and unless PPL's Second Plan actually creates 258 MW of incremental hosting capacity, then the Second Plan's benefits-to-cost ratio is very likely to sink below 1.0 – which in turns means that it will cost ratepayers more than the benefits it will provide. If none of these hosting capacity benefits materialize, the benefits-to-cost ratio falls to 0.25, and if only half of the incremental hosting capacity is used, the benefits-to-cost ratio falls to 0.65. *See Petition of UGI Utilities, Inc. – Electric Division for Approval of its Energy Efficiency and Conservation Plan*, Pa. PUC Docket No. M-2020-2210316 (March 15, 2012), p. 10 (declining approval of a program with a TRC benefit/cost ratio of 0.49). In both cases, the Plan would be a bad deal for ratepayers. Lastly, without Mr. Wishart providing an analysis of what portion of the "Avoided Distribution Infrastructure Investments" benefit would flow to ratepayers, it is safe to assume that the benefits-to-cost ratio specifically for ratepayers would be significantly below even the ratios as recalculated above, because a portion of the "Avoided Distribution Infrastructure Investments" described by Mr. Wishart are likely to benefit DER owners rather than ratepayers broadly.

In sum, the single-most critical component of Mr. Wishart's benefits projection fails. PPL has not provided this Commission with a basis upon which to approve its plan.

ii. PPL Failed to Conduct the Analyses Required by the Commission; and the Analyses it Did Do are Flawed

PPL's cost/benefits analysis is also of limited utility not just because of what it says, but also because of what it doesn't say.

As a condition of approval of its Pilot program, the Commission required that PPL compare the costs and benefits of active management of DERs by PPL's Devices, to the benefits available by using inverter autonomous grid support functions. PPL St. No. 1, p. 13. As we explain on p. 35, PPL's evaluation in the context of its Pilot was inadequate. Nor did Mr. Wishart elect to include such analysis in his cost-benefit analysis because he "did not see any value in conducting an analysis on smart inverters with autonomous operation that are already required." PPL St. No. 10-RJ, p. 4. However, this omission deprives the Commission of a complete record upon which it can decide if PPL's $81 million active management plan is worthwhile.

To date, the benefits yielded from three years under the Pilot have been meager. For example, the stated purposes of the Plan included managing DER reactive power "to help resolve voltage violations at the point of interconnection" (PPL St. No. 3, p. 40) and "to meet overall distribution system voltage objectives" (PPL St. No. 4, p. 19); increasing hosting capacity and deferring capital upgrades (PPL St. No. 3, p. 38); and accessing a remote on/off capability (PPL St. No. 3, p. 54). However, to date, PPL has not yet managed DER reactive power "to help resolve voltage violations at the point of interconnection," PPL St. No. 3, p. 43; avoided specific investments, PPL St. No. 3, p. 49; or accessed remote on/off capability, PPL St. No. 3, p. 55. As to resolving overall distribution system voltage issues, the JSPs calculate that PPL's active management has resulted in no change to the number of voltage violations 63% of the time; increased voltage violations 27% of the time; and reduced voltage violations only 10% of the time. JSP St. No. 6, p. 16. Further, as noted by OCA Witness Nelson (OCA-1-SR, n. 17): "Company witness Miu demonstrated the *capability* of active DER management to mitigate voltage violations …, while still ignoring the *magnitude* of this affect across the system which would indicate how valuable this benefit really is." *See* PPL St. 7-R at 9-10. Thus, PPL has failed to provide information on when, where and how frequently its active management assisted in resolving overall system voltage issues.

As autonomous smart inverter grid functions are able to achieve most if not all of the above-stated objectives, it was incumbent upon PPL to do as the Commission ordered and evaluate the incremental benefits to be obtained through active management as against those obtained anyway from autonomous grid support functions. As PPL did not do so, its Petition should be declined.

Indeed, Mr. Wishart and PPL have handicapped the Commission's ability to approve PPL's Petition, as they have failed to provide an analysis of any alternatives to active utility control, again, an approach not adopted by any other jurisdiction. Thus, Mr. Wishart conducted no analyses of alternate approaches, such as Flexible Interconnection, despite there being ample literature on such programs.[46] Flexible interconnection offers reduced interconnection costs for DER owners who elect to limit the power that their systems can export to the grid, such as California Rule 21's

[46] Astonishingly, Mr. Wishart states: "I did not include analysis of other policies because there were not any well-formed policies with supporting data that I could use to perform a cost-benefit analysis." PPL St. No. 10-SR, p. 23.

Limited Generation Profile,[47] under which Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company define conditions of operations to allow DERs to perform within existing hosting capacity constraints and avoid triggering distribution grid upgrades. JSP St. No. 9, p. 11. The UL 3141 standard, which certifies system-level Power Control System functionality to provide time-based import and export limitations, can serve as the basis of flexible interconnection options for customers. JSP St. No. 6-SR, p. 10.

Nor did PPL analyze any other mechanism, including lower-cost mechanisms, or approaches to employ in "controlling" the DER other than PPL's Device, such as Enphase's customer-owned modem that communicates through the cloud. Enphase witness Marc Monbouquette testified that the Enphase modem should be able to provide an equivalent level of reliability to PPL's DER Management Device, one of which is a cellular gateway. The Enphase modem is listed for $410.50, and can easily be installed by customers themselves. JSP St. No. 6-SR, p. 10. By contrast, the weighted average cost of PPL's DER management device is $959. PPL St. 10-R, Table SWW 5. The Enphase modem's lower per unit cost, reduced or avoided costs from labor and truck rolls to oversee installation, and op-ex treatment for customer rebates rather than capitalizing equipment cost and adding it to the ratebase, would provide greater net benefits for PPL customers. JSP St. No. 6-SR, p. 11.

PPL also failed to analyze whether it could procure grid services using third-party aggregators. A third-party aggregator is a non-utility entity that controls the behavior of DERs in response to dispatch signals from the utility, or price signals from wholesale electricity markets. By controlling a fleet of DERs in unison, the third-party aggregator can provide higher-order grid services that can make meaningful contributions to satisfying a utility or energy market's reliability

[47] *See* Ordering Paragraph 2, p. 102, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M527/K981/527981713.PDF.

requirements. JSP St. No. 6, p. 20.

The SolarEdge inverter can automatically communicate with its built-in modem, eliminating the need for a DER Device or an AMI network to talk to the Device. It eliminates also the need for the truck rolls and equipment costs associated with these installations. The lower cap ex reduces costs for ratepayers. JSP St. No. 7, p. 21; JSP St. No. 7-SR, pp. 22 – 23.

Another stated purpose of PPL's Program was to facilitate PPL's monitoring of real power, reactive power and voltage (PPL St. No. 3, pp. 13). Here too, as a condition of approval of PPL's Pilot Program, the Commission also expressly required that PPL test and evaluate the costs and benefits of monitoring DERs through PPL-owned devices connected to customer-owned inverters, as compared to maintaining distribution system status visibility through other means (e.g., automated reading equipment, advanced distribution systems ("ADMS"), modeling). Recommended Decision, Docket No. P-2019-3010128, ¶ 54.

More than 67% of all projected program benefits, or $98.6 million of the $146.6 million, come just from monitoring, rather than active management. JSP St. No. 4-SR, *citing* PPL St. No. 10-R, p. 9, Table SWW-2. However, again, in derogation of the Commission's Order, PPL performed no analyses of alternative methods it could use to obtain monitoring data, such as use of Application Programming Interface (API) to provide the ability to communicate with inverters, receive data from the inverters, and even control the inverters for any third party that has been granted access. JSP St. No. 4-SR, p. 22. APIs provide data and access over "the cloud, so can be provided via a network of remote serves that are accessible over the internet." JSP St. No. 4, p. 22. The Government of Western Australia (which receives upwards of 80% of its total energy from solar) is using this solution. JSP St. No. 4-SR, p. 23; JSP Ex. JG-12SR.

Finally, when PPL did in fact compare the use of autonomous smart inverter functions compared to active management in regard to the efficacy of voltage control in its 2024 DER Management Report ("Report"), the analysis was notably unscientific, as described by JSP Witness Monbouquette.[48] Portions of PPL's analysis in the Report claimed benefits of active management in reducing the duration and frequency of voltage violations, but only when compared to a "Grandfathered Group" of DERs that were not subject to active management or smart inverter settings. Those portions of the analysis provide no information to the Commission regarding the benefits of active management compared to autonomous smart inverter settings in regard to voltage regulation.[49] When PPL did compare feeders with actively managed DERs to those with only autonomous smart inverter settings, PPL significantly limited its analysis to Control Group 1 feeders, which comprised DERs on 75 specific circuits, and completely ignored any comparison between actively managed DERs and Control Group 2, which comprised 1,000 DERs located across PPL's grid and which had autonomous smart inverter settings activated.[50] In fact, despite Control Group 2 being the largest control group in the Pilot, PPL never used Control Group 2 to provide any conclusive evidence regarding the relative value of active management versus autonomous settings, effectively and arbitrarily excluding a substantial number of the Pilot's control group participants from its analysis.

In its Report, even when PPL compared Control Group 1 feeders to actively managed feeders, PPL never conducted any scientific regression analysis (an industry best practice, *see* JSP St. No. 6, p. 15, *citing* a Harvard Business Review article) to determine whether changes in voltage frequency and duration were due to the active management, the smart inverter settings, or numerous other factors that affect voltage. In its Report, PPL simply stated that the "the impact of

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[48] JSP St. No. 6, pp. 13-19.
[49] JSP St. No. 6, p. 13-14.
[50] JSP St. No. 6, p. 14.

active management on the duration and frequency of voltage violations is readily apparent."[51] PPL stated in its response to JSP-II-9(a) and (b) that "a regression model has not been necessary based upon the analyses conducted regarding the voltage violations," because factors that could have explained differences in voltage violations between control groups "have been consistently present before and after the pilot and are not believed to be the driver in this difference for voltage violation frequency and duration."[52] However, PPL acknowledged in its 2024 Report that Control Group 1 feeders and actively managed feeders had notably different voltage conditions at the start of the Pilot, emphasizing the need for a more rigorous and scientific regression analysis, which PPL did not conduct. In short, while PPL's Pilot was intended to compare the ability of actively-managed inverters to those using autonomous smart inverter settings in providing voltage control, PPL's actual comparison was significantly flawed – and the question of voltage regulation has been relegated to a much more minor portion of Mr. Wishart's analysis.

PPL's failure to analyze alternatives, in addition to constituting blatant disregard of Commission Orders, deprives the Commission of a sound record upon which to base its finding that PPL's Program benefits justify the costs, especially when weighed against the harms.

iii. PPL Has Failed to Analyze the Magnitude of Harms Its Program Has Done and Will Do to the JSPs, to Other Solar Customers and Companies, and to the Public Interest Generally

PPL's program does not meet the reasonableness, just, and public interest standard, including because PPLhas not accounted for the harms its program has done and will do, if approved, to the JSPs and to the public interest writ large. While PPL purports to having done so in the analyses provided on rebuttal (as opposed to its case in chief), the JSPs note that even if it had, the record would still be incomplete, as the JSPs could only put forth evidence as to the harms

[51] See, PPL Electric Exhibit CD-4, p. 15.
[52] JSP St. No. 6, p. 15.

they experienced first-hand. (The JSPs did discuss harms done to 6 non-JSP inverter manufactures above, in Section III.b.ii., that were clear in the record.)

1. PPL Fails to Account for the Lost Sales Resulting from its Program Restrictions

JSP Witness Zavala provided evidence that AHC denied sales to at least 52 customers because it could not provide the customers with the products that the customers requested. JSP St. No. 2-SR, p. 11; Ex. JSP-NZ-6SR (REDACTED). Mr. Zavala testified that Pennsylvania is AHC's second largest market and would be its largest, if AHC, a Tesla Premier Certified Installer with a focus on the Tesla Powerwall and Solar Roof ecosystem, were still able to sell, install, and service Tesla products in PPL territory. JSP St. No. 2, pp. 2, 3.

JSP Witness Michael Shadow testified that his company, Sun Directed has denied service to larger-size single phase commercial projects because it could not use the inverters that in its professional judgment were the best value for its customers, as they were not on PPL's Approved List. JSP St. No. 3, p. 4. Mr. Shadow testified that as there are 3 main utilities in Central Pennsylvania, PPL's program has limited 1/3rd of Sun Directed's business. JSP St. No. 3, p. 5.

PPL disputed Mr. Zavala's claim that 6 lost sales were attributable to PPL's program, arguing that those sites were located outside of PPL's service territory, PPL St. No. 2-RJ, p. 9, which effectively concedes that AHC did indeed lose at least 46 sales. Mr. Zavala testified that his information on location was based on, *inter alia*, copies of the customers' utility bills, and noted the difficulty in obtaining address information from PPL. JSP St. No. 2-SR, pp. 9 - 10.

PPL disputed Mr. Shadow's math as to whether PPL's being 1/3rd of Sun Directed's territory equated to 1/3rd of Sun Directed's business, PPL St. No. 2-RJ, again, effectively conceding that in fact, Sun Directed has lost business. Mr. Shadow responded that the density in PPL territory explains his common sense conclusion. JSP St. No. 3-SR, p. 9.

PPL disputed both Mr. Zavala's and Mr. Shadow's lost sales claims on grounds that both could have substituted other products. PPL St. No. 2-R, pp. 19, 22. Mr. Zavala testified that PPL's solution was "not feasible," JSP St. No. 2-SR, p. 6, as there is no substitute for the Tesla Powerwall battery with the integrated inverter, JSP St. No. 4; that in his "real world" experience, JSP St. No. 2-SR, p. 6, "mixing and matching" products meant the customer had to chase down two manufacturers if it wanted to pursue a warranty claim, *Id*., and resulted in sub-optimal product performance (for example, he could not monitor the performance of a Tesla Solar Roof using the non-Tesla inverter), *Id*., p. 6, and higher prices (for example, because he would have to hire a third-party designer to redesign a SolarRoof so it could accommodate non-Tesla mid-circuit interrupters, which, he testified he had not found on the market). *Id*.

Mr. Shadow testified that substitution was infeasible because PPL-approved products were higher-priced, based on cost comparisons he'd run for real clients, showing a price differential for a larger size single-phase residential project of [**REDACTED]**,[53] and for a smaller project, of **[REDACTED]** . In response to PPL's challenge to his comparing the Tesla "string" inverter to the higher-priced non-Tesla micro-inverter, Mr. Shadow testified that the PPL-approved non-Tesla string inverters were inverters with which his field staff had no experience installing, were not made in America, which would jeopardize customers' ability to qualify for grants, or were products he had never heard of, so could not recommend them to his customers. JSP St. No. 3-SR (HIGHLY CONFIDENTIAL), pp. 6 - 7.

Astonishingly, PPL's Ms. Dombrowski-Diamond asserted that "from [her] perspective, [the price differential for the smaller project] "does not appear to be significant enough of a difference

[53] Regarding the larger-size project, *see* JSP St. No. 3, p. 4; JSP St. No. 3-SR, p. 2. Regarding the smaller size, *see* JSP St. No. 3-SR, pp. 3, 7; Ex JSP-MS-1 (HIGHLY CONFIDENTIAL) (price list), and Ex. JSP-SD-1SR (cost comparison).

for a customer not to move forward with a project ..." PPL St. No. 2-R, p. 26. Mr. Shadow responded:

> With respect, I find Ms. Dombrowski-Diamond's views to be highly insensitive to the concerns of the average family. A **[REDACTED]** price difference may seem small to an employee of a large, investor-owned utility, and might indeed not be enough to move the needle with regard to a decision on an investment, but that amount of money can make a huge difference to the average family. Further, when faced with a choice between types of energy investments, the difference indeed could be enough to incentivize a customer to select the less expensive (and potentially dirtier) fuel source. Even to a small business, **[REDACTED]**can be significant.

Ms. Dombrowski-Diamond had inserted her own estimate of the price difference, based on a different set of assumptions than were employed by Mr. Shadow, PPL St. No. 2-RJ, p. 12, but did not explain them.

PPL asserted that Mr. Zavala's and Mr. Shadow's complaints should be with Tesla for not electing to seek inclusion of its inverters on PPL's approved list, rather than with PPL for establishing a list. PPL St. No. 2, pp. 16 – 17. Both responded that they did not know Tesla's reasons for not doing so, but objected to PPL's barring use of products that have been certified as meeting national standards but not PPL's, JSP St. No. 2-SR, p. 4; JSP St. No. 3-SR, p. 5, depriving customers of their ability to choose the products they wish and that they would recommend. JSP St. No. 2, p. 4; JSP St. No. 3-SR, p. 5.

PPL did not respond to Mr. Zavala's demonstration that the lost sales deprived Pennsylvanians of hundreds of kW of clean energy and battery storage, JSP St. No. 2, p. 5; JSP-NZ-1 (HC);[54] of access to less costly and more efficient products, JSP No. 2-R, pp. 6 – 7;[55] of revenues, due to the prohibition on the use of non-approved products, JSP St. No. 2, p. 5 (HC);

[54] Mr. Zavala calculated that as of September 24, 2024, the 31 lost sales would have produced 512.13 kW and 114 batteries. KSP St. p. 2, p. 5/Ex. JSP-NZ-1.

[55] The Tesla Powerwall accounted for more than half of the U.S. national solar-plus-storage battery manufacturer shares by installation count from 2018 to 2023. JSP St. No. 4, p. 23.

and of customers' ability to choose the products they desired. JSP St. No. 2, p. 2; JSP St. No. 3-SR, p. 5.

JSP Witness Graham provided evidence that Tesla was forced to redesign and downsize four solar systems, totaling a cumulative reduction of 37.6 kW-AC of those systems and a commensurate loss in sales,[56] due to PPL's March 2023 restriction[57] that limited Tesla installs containing SolarEdge or Delta inverters with Zigbee communications chips to single-inverter installs. Additionally, Tesla ultimately ceased PPL installations due to the difficulty of operating under the Pilot, resulting in untold sales losses.[58] In October 2023, Tesla closed its Tesla Energy warehouse in Norristown, Pennsylvania due solely to ceasing PPL residential energy installs. *Id.*

2. PPL Has Failed to account for Additional Losses to Pennsylvania Businesses and Customers

Trinity Solar testified it has not lost sales due to PPLs' program, but has lost profits, as it has absorbed the higher costs of doing business in PPL territory. As of the date Trinity filed its Initial Testimony, Trinity calculated it had lost approximately **[REDACTED]** in profits based on the prices paid in 2023 on the 1,700 projects it installed in PPL territory with PPL-approved inverters, as opposed to the inverters Trinity would have chosen to use, and the higher labor costs associated with installing the approved inverters, as well as additional man-hours, personnel, and truck rollouts uniquely associated with installing and servicing installations containing or potentially containing PPL's Device. JSP St. No. 5, pp. 3 – 4, 5; JSP St. No. 5-SR, pp. 3, 7.

Trinity showed also that servicing customers' inverters takes far longer under PPL's program, due to PPL's being the only entity able to install or remove its device from a customer's inverter, JSP St. No. 5, p. 5, in some cases up to 75 days, PPL St. No. 5-SR, p. 6; Ex. JSP-RP-4SR, causing

[56] See JSP Ex. JG-8SR - HIGHLY CONFIDENTIAL Ex. PPL to JSP-VI-6 Att. JG-1
[57] See Ex. JSP-JG-4 CONFIDENTIAL
[58] See JSP Statement No. 4, at p. 17

significant customer dissatisfaction, JSP St. No. 5-SR, p. 6; Ex. JSP-RP-5SR. Trinity also showed these delays have increased Trinity's costs by about an additional **[REDACTED]** per year, due to additional days of field techs' time, JSP St. No. 5, p. 5, and the costs associated with Trinity's having to hire an additional staffer to coordinate service visits. JSP St. No. 5, p. 7; JSP St. No. 5-SR, pp. 5 - 6. Trinity testified that this coordination between PPL, Trinity, and the customer is unique to PPL because of the Pilot and is not required in other areas. JSP St. No. 5-SR, p. 7.

Green Way showed that its customers have experienced lengthy delays in receiving permission to operate ("PTO"), as a result of their having to await PPL's installation of its Device, sometimes up to 47 days following the date of the electrical inspection. JSP St. No. 10, pp. 3 – 4; Ex. JSP-WS-1, Slides 16-23; and testified how a 38-day delay in obtaining PTO cost one customer $116,000.00, because his ability to obtain financing was pegged to his showing that his system was successfully operating for 30 days. JSP St. No. 10, pp. 5-6.

Green Way testified that the delay Green Way and its customers are experiencing is unique to PPL territory, as no other utility has a requirement to install utility-owned equipment on inverters. JSP St. No. 10, p. 4.

PPL's disputes as to Trinity's claims that PPL-approved equipment costs more (PPL St. No. 2-R, p. 27), were met with the same responses as were put forth by AHC and Sun Directed. *See* JSP St. No. 5-SR, pp. 2 – 5 (that Trinity priced the equipment its staff knows how to install and that Trinity believes is the best quality and American-made; and that Trinity's price estimates included the additional labor costs associated with installing the additional components comprising the PPL-approved equipment). Trinity also answered that it employed assumptions based on its average installations, which were significantly larger than the assumptions employed by PPL. *Id.*, p. 4.

In her Rejoinder Testimony, to which Trinity had no opportunity to respond, Ms. Dombrowski-

Diamond asserted that the reason Trinity's price estimate of PPL-approved equipment was higher was because Trinity included "optional" items in the systems it priced. PPL St. No. 2-RJ, p. 22. The record shows, however, that equipment Ms. Dombrowski-Diamond called "optional" (for example, SolarEdge's power optimizer), is in fact integral to using the PPL-approved inverter. *See* Exhibit JSP-RP-2SR (HC), and Exhibit JSP-NZ-3SR (HC).

PPL claimed Trinity overstated the numbers of times service visits required coordination. PPL St. No. 2-R, pp. 30 – 31. Trinity responded that it needs to coordinate in all instances, because it does not know in which inverters PPL has installed its Device, JSP St. No. 5-SR, p. 5, and that Ms. Dombrowski-Diamond's analysis erroneously included projects installed three years before the Pilot commenced. *Id*., p. 7.

PPL testified that delays in issuance of PTO are generally due to inclement weather or discrepancies found when field visiting the customers' system, neither of which they demonstrated. PPL claimed that PTO was delayed at Green Way's installations because of missing signatures from the customer on the certificates of inspection, PPL St. No. 2-R, pp. 52-53, but could not counter Green Way's evidence showing all signature lines completed. JSP St. No. 10-SR, p. 5.

3. PPL's Program Blocks or Limits Market Entry

Enphase expended significant resources seeking to obtain and maintain PPL approval of and support for its inverters, which were certified as meeting an IEEE 2030.5 interface, per California Rule 21 requirements, Ex. JSP-MM-3SR, because PPL initially sought to require all inverter products to be capable of communicating through DNP3 or SunSpec Modbus, due to PPL's having not yet completed an integration of IEEE 2030.5 into its AMI network. JSP St. No. 6, p. 5. Upon PPL's finally agreeing to use Enphase's product, Enphase sent free equipment to PPL's lab, and provided remote support as PPL worked to integrate Enphase into its servers. *Id*.

Enphase estimates it took three months of lab work for PPL to successfully "get the client to communicate with their servers," followed by ongoing troubleshooting and debugging tasks to ensure that commands were working as intended, and the expenditure of significant resources by both (approximately 250 hours of PPL staff time, and 150 hours of Enphase staff time). *Id*., p. 6. In addition to losing sales during this four month period, Enphase observed several installers and/or pending projects switch to competitor products. *Id*., p. 5.

Enphase testified it has not been required to dedicate this level of attention to operations in other similarly sized utilities' territory. JSP St. No. 6, p. 6.

When the Pilot commenced on January 1, 2021, SolarEdge inverters purchased by customers who were awaiting PTO did not yet meet the not-yet effective UL 1741 SB Standard. *See* JSP St. No. 7, p. 4. To obtain PTO for its customers, SolarEdge customized a solution that involved showing PPL its inverters already contained the "read functions" that would be required by UL 1741 SB, JSP St. No. 7, p. 4, using a function SolarEdge calls Modbus mapping. PPL Ex. AD-22R (HIGHLY CONFIDENTIAL). SolarEdge delivered Modbus register maps to PPL, and helped train the PPL team on how to use the maps. JSP St. No. 7, p. 4. SolarEdge estimates its development of this custom solution required that an employee dedicate a full two weeks of work (worth approximately $6,460) over the period from January 1, 2021 to January 28, 2021, JSP St. No. 7, p. 4, pp. 4 – 5, diverting his time from securing new business. JSP St. No. 7, p. 5. SolarEdge also lost or experienced delays in sales during the 28-day period it awaited approval of its inverters' inclusion on PPL's Approved List. JSP St. No. 7, p. 3.

PPL's restrictions and its requirement for supplemental utility testing also block installation of products that are in compliance with the IEEE 1547-2018 and UL 1741 SB standards but which have not submitted for PPL's testing. JSP St. No. 4, p. 22. One prominent example is Tesla's solar inverter and the inverter integrated into its Powerwall batteries, which are certified to the required

IEEE and UL standards but which are not on PPL's Approved Smart Inverter List, thus impeding or suppressing sales and installation of Tesla solar panels, solar roofs, and battery storage products in PPL territory, and depriving PPL customers of the savings and major efficiencies available through, in particular the Tesla Powerwall battery. *See* JSP St. No. 2-SR, p. 7.

Finally, we discuss, *supra*, in Section III.b.i. that PPL's restrictions have limited 41 inverters to multi-use configurations due to PPL's improperly requiring that inverters be able to be networked. These limitations restrict the ability of the manufacturers of these inverters to fully participate in PPL's market as they would elsewhere, limiting their competitiveness compared to inverters that are allowed to be installed in multi-inverter systems.

4. PPL Fails to Account for the Interference with Customers' Communications and Power Generation Caused by its Device

In at least 27 Tesla multi-inverter solar systems installs involving Delta or SolarEdge inverters, and all involving ZigBee communications modules, communications and data from customers' systems were fully or partially knocked offline due to the presence of PPL's DER Management Device. JSP St. No. 4-SR, p. 4-5; JSP Ex. JG-2SR HIGHLY CONFIDENTIAL. Cumulatively, those 27 systems had one or more inverters not sending communications for 6,933 days, or an average of 256 days/system. JSP Ex. JG-2SR HIGHLY CONFIDENTIAL.

The disruptions commenced when PPL installed its Device and changed the inverter ID in multi-inverter solar installations, JSP St. No. 4, p. 7, resulting in neither Tesla nor its customers able to see communications data from any inverter other than the inverter numbered "1," JSP St. No. 8, which blocked them from seeing how the entire solar system was producing and functioning.

Beginning in March 2023, PPL informed Tesla it would not grant PTO to any multi-inverter Tesla solar system using ZigBee in a SolarEdge or Delta inverter, Ex. JSP-JG-3; Ex. JSP-JG-4 (HC), causing Tesla to have to redesign four Tesla solar systems, and customers being forced to reduce the size of the systems from what they originally ordered. While PPL Witness Dombrowski-Diamond states that PPL had lifted its single-inverter restrictions on such systems, such relief was contingent on Tesla developing a bespoke software patch that Tesla was unable to develop, which meant the restrictions were never in fact lifted.[59]

Ultimately, in the summer and fall of 2024, PPL determined that it could allow for full communications for both Tesla and PPL systems using SolarEdge inverters (15 of the 27 Tesla-installed systems experiencing communications disruptions) simply by using a "register map for the Modbus register 700 series" that PPL obtained from SolarEdge in order to fix this issue[60] rather than requiring a bespoke Tesla software patch. By using the register map, PPL was able to set a unique Modbus ID number for each SolarEdge inverter, which in turn provided full system data communications for the customers, for PPL, and for Tesla. However, the fix came only after 2-to-3 years of troubleshooting and data communication disruptions for Tesla and its customers.

Similarly, Tesla and PPL have recently found that they may employ a grid code used in New York to resolve the disruptions to systems using Delta inverters. *See* JSP St. No. 4-SR, pp. 7 – 10. Again, while the result has been positive, the significant amount of time and resources spent until the "fix" was discovered, as well as values to customers lost, reflects another instance of PPL's Program resulting in harms to the solar community.

Tesla has installed roughly 453,000 residential solar systems across the country with one or more Zigbee communications modules installed. In no other territory have Zigbee communications modules posed the communications problems Tesla experienced in PPL's territory. JSP St. No. 4, p. 9. In no other territory has a utility limited installations of inverters with ZigBee modules to a single inverter. JSP St. No. 4, p. 9. All the inverters Tesla installed under PPL's Pilot

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[59] See, JSP St. No. 4-SR, pp. 15-16.
[60] PPL St. No. 2-R, p. 37.

were on PPL's Approved Inverter List, and Tesla has produced evidence showing that the ZigBee communications modules Tesla used in the PPL-approved inverters were either already installed, or approved for use, by SolarEdge and Delta. JSP St. No. 4, p. 2; Ex. JSP-JG-2.

Enphase recorded 18 incidents between April 30, 2024 and July 22, 2024 in which PPL's DER Management Device disrupted communications and power production from customers' inverters. JSP St. No. 6, p. 7. In 8 of the 18 instances, customer communications were disrupted because PPL was sending commands to the Enphase IQ Gateway (which manages local and cloud communications at the customer's premises) in the wrong units. JSP St. No. 6, p. 8. Regarding those instances, PPL asserted that Enphase "directed" it to use the wrong units (PPL St. No. 2-R, p. 33), but the evidence PPL offered in support (PPL Ex. AD-19R) contains no indication that Enphase provided any errant "direction." *See* JSP St. no. 6-SR, p. 2.

In these 8 instances, the disruption also halted power production from the customers' solar systems. JSP St. No. 6, p. 8; Ex. JSP-MM-3 (noted as "Issue 1"). REDACTED Ex. JSP-MM-3. The 8 systems experienced at least 419 cumulative days of solar power production downtime, resulting in an estimated 12,570 kWh of lost energy, assuming each system produced an average of 30 kWh of energy per day. In 10 of the 18 instances, communication traffic emanating from PPL's modem clashed with communication traffic over the customer's Wi-Fi related to local system operations, disrupting the customers' systems' communications. JSP St. No. 6, p. 8. In 5 of these 10 instances, the disruption also halted power production from the customers' solar systems. JSP St. No. 6 p. 8; Ex. JSP-MM-3 (noted as "Issue 2"). PPL has since changed all DER Management devices to a different LAN IP, which resolved the issue. PPL St. No. 2-R, p. 33.

As a result of these disruptions, Enphase's customers experienced at least 617 cumulative days of solar power production downtime, and at least 609 cumulative days of communications downtime. JSP St. No. 6, p. 8; Ex. JSP-MM-3.

Cumulatively, because of the disruptions caused by PPL's installation of its Device, the Commonwealth lost at least 18,410 kWh of solar power generation from these customers' inverters. JSP St. No. 6, p. 9. Cumulatively, because of the disruptions caused by PPL's installation of its Device, Enphase customers lost at least $1,851 worth of net energy metering credits, as well as lost SREC values. JSP St. No. 6, p. 9. Cumulatively, Enphase expended approximately $2,400 worth of labor to develop software fixes to resolve the two issues at the 18 sites. Enphase's costs do not include costs incurred by installers, who had to travel to each of the 18 sites at least once to perform troubleshooting and system reset activities on the physical systems. JSP St. No. 6, p. 9.

SolarEdge estimates it has spent 210 hours over the past two years supporting PPL's implementation of its program determining how to configure multi-inverter systems. JSP St. No. 7, p. 6; Ex. JSP-JB-2, Slide 14. Historically, PPL's Device required a Modbus RTU port, while SolarEdge inverters have only a Modbus TCP (or ethernet) port available. JSP St. No. 7, p. 5. At some point during the Program, PPL replaced the type of Device it was using with one able to be used with SolarEdge's Modbus TCP port. PPL St. No. 2-RJ, p. 40.

SolarEdge has not been required to meet utility-specific testing requirements that go beyond the requirements for IEEE and UL certification, or to provide ongoing technical support, in any other jurisdiction. JSP St. No. 7, p. 6.

Finally, although they have been resolved, Sun Directed also provided evidence of instances in which customers were inconvenienced, and deprived of the value of their solar equipment, and Sun Directed lost money servicing their systems, which experienced interference as a result of PPL's DER Device installation. JSP St. No. 3, pp. 5 – 6.

5. PPL's Program is Blocking or Impeding Competition from Third-Party Grid Services Providers

JSP witness Kevin Joyce of Tesla testified that PPL's ability to assert primary control of a customer's inverter will be a significant blocker for third-party aggregators of battery energy storage in PPL's territory, and will block the provision of wholesale market grid services from aggregated DERs by creating unique and excessive risk and complexities for aggregators that ultimately will dissuade them from aggregating Pennsylvania-based DERs.[61] Mr. Joyce testified that accommodating the utility control required by PPL's Pilot and Plan alongside a VPP program would require third-party aggregators, such as Tesla, to create novel technical solutions that would be unique to the PPL territory and would need to be capable of managing multiple points of communication and control.[62] Mr. Joyce testified that the need to create such a novel technical solution would be costly and would act a significant barrier for aggregators to enter PPL's territory, particularly for aggregators looking to participate in PJM.[63] Mr. Joyce also testified that the complexities of managing multiple points of communications and control created by PPL's Pilot and Plan, and of incorporating PPL management into VPP forecasting and dispatch strategies, would itself create an entirely new risk and complexity that is difficult for aggregators to assess and quantify, causing a significant deterrent to market entry.[64]

Enphase testified that PPL's ability to update reactive power setpoints has the effect of reducing the active power potential of resources such as solar and batteries, which can otherwise be controlled by manufacturers' cloud Application Programming Interfaces ("APIs") for participation in grid services programs. JSP St. No. 6, p. 21.

Enphase also testified that PPL's hegemony over DER control presents a high degree of uncertainty for prospective third-party aggregators, interfering with the latters' ability to be able to

[61] *See*, JSP St. No. 8, at pp. 6-12.
[62] *See*, JSP St. No. 8-SR, at p. 3.
[63] *See*, JSP St. No. 8, at pp. 9-10.
[64] *See*, JSP St. No. 8-SR, at pp. 3-5.

confidently deliver grid services, particularly wholesale electricity market reliability services.

SolarEdge also testified that PPL's program blocks its ability to confidently develop an aggregation program. JSP St. No. 7, p. 19.

PPL has uniformly rejected the JSPs' claims that its program causes sufficient uncertainty that will block aggregators from entering the market. Indeed, PPL appears not to have taken the JSPs' claims seriously. PPL's primarily argued, for example, that Tesla "already has to consider many variables that have a greater effect on their DER systems' generation, such as weather, circuit outages and equipment failures." PPL St. No. 11-R, p. 32. The JSPs contend that PPL's argument overlooks the JSPs' main concern that the new uncertainties introduced by PPL's program are unique to PPL's territory, and pose unique risks and complexities that would be costly to design around. JSP St. No. 8-SR, p. 3.

In response to the JSPs' claims of uncertainties, PPL's Bethany Johnson opined that third-party aggregators such as Tesla " . . . should "know the capacity and capability of each system within its portfolio and be able to develop a range of possibilities based on that information." PPL St, No. 11-R, p. 33. Ms. Johnson offered as a solution that Tesla could build a risk premium into its payment to defray the risk." *Id*., p. 32.

Tesla's Mr. Joyce responded that Ms. Johnson's testimony (and suggestion that Tesla charge a risk premium) shows her acknowledgement that PPL's program poses risk. JSP St. No. 8, p. 3.

PPL's witness Ms. Dombrowski-Diamond, rejected the JSPs' claims that PPL's occupation of the inverters' communications port denies third party aggregators access to the same, insisting during the Hearing that "[w]e have multiple installations [with] more than one connection for communications." Hrg. Tr., p. 343.

Ms. Dombrowski-Diamond's response does not address JSP Witness Lydic's statement that

PPL's Device physically blocks access to the port for any inverter that has a single port. Mr. Lydic states that to the extent that a third-party aggregator may need access to an inverter's communication port in order to aggregate DERs in PPL's territory, the aggregator likely would be unable to access that port, because PPL's Tariff requires that PPL "be permitted to actively monitor and manage the grid support functions of DER inverters using the DER Management Device and the Company's Distributed Energy Resources Management System (DERMS)."[65]

Ms. Dombrowski-Diamond testified that "[a]ll inverters are able to communicate with more than one communication device[,]" PPL St. No. 2-R, p. 44, offering as support that "this has been true with all customer-owned [SCADA] systems installed in PPL Electric's service territory that have a DER Management Device installed," *Id*. 44, and that if the manufacturers cannot communicate, its because "the manufacturers are [not] following the proper communication protocols required by the applicable standards" (*Id*., p. 45).

The JSPs responded, that SolarEdge equipment "cannot communicate with multiple entities at the same time;" that SolarEdge equipment is in fact "adhering to the proper communications protocols required by the applicable standards," but that IEEE 1547-2018 "is silent about communicating with multiple entities at the same time for the purposes of [providing] grid support." JSP St. No. 7-SR, p. 23. As for SCADA systems, the JSPs testified that Ms. Dombrowski-Diamond may be correct with regard to a much larger, industrial user "(i.e., one that can afford a $100,000.00 SCADA system) [, b]ut she is incorrect with regard to the residential systems at issue in this litigation." JSP St. No. 7-SR, p. 22. Ms. Dombrowski-Diamond responded that "[t]here are smaller SCADA systems available for homeowners," and that she had seen one "at a Tesla location," but that she had "not polled [PPL] territory" so as to be able to know how widely SCADA systems

[65] JSP St. No. 9-SR, at p. 14.

are used in residences. Hrg. Tr., p. 346.

The *Board-Tech* decision, discussed above, is instructive. While not exactly on point procedurally (that case involved an entity's failure to follow proper procedures to cancel a NRTL registration), the underlying principles are the same – that standards can be mis-used by a competitor to try to gain an unfair advantage. The court held that "[t]he certification mark regime "protects a further public interest in free and open competition among producers and distributors of the certified product." *Id*. at *9.

Here, the JSPs have shown that even though they are certified to the standards (as required by Pennsylvania), PPL's mis-use of the standards has resulted in squeezing the JSPs out of the grid services market. This is precisely the danger the Commission noted could occur if utilities themselves participate in wholesale markets in the form of, and in competition with, DER aggregators, and on which it solicited comment. *See* ANOPR, p. 44. Such result would conflict with the Commonwealth's legislative policy favoring competition over regulation. *See Investigation of Pennsylvania's Retail Electricity Market; End State of Default Service*, Pa. PUC Docket I-2011-2237952, Opinion (Feb. 14, 2013), p. 10.

6. PPL Has Failed to Account for its Device Installations Violating the National Electrical Code, Voiding Customers' Warranties, and Causing Thermal Damage

Finally, PPL's method of installing its Device in SolarEdge inverters has caused harm to SolarEdge, to its customers, and to the public. In each of the nearly 8,000 times PPL installed its Device in SolarEdge inverters, PPL St. No. 2-RJ, p. 34, it did so in violation of the National Electric Code, voided SolarEdge's customers' product warranties, and caused thermal damage to customers' inverters, precisely the type of harm the NEC aims to prevent. JSP St. No. 14-SR, p. 3.[66]

[66] *See* NEC 90.1(A), which states: "The purpose of this Code is the practical safeguarding of persons and property from hazards arising from the use of electricity."

A. PPL's Method of Connecting its Device to SolarEdge Inverters Violates the NEC

PPL's installations in SolarEdge inverters are clearly subject to NEC requirements. Section 690.4 (General Requirements) covering Solar Photovoltaic Systems states the article applies to inverters for such systems. More broadly, NEC Section 90.2(A) is clear that the NEC "covers the installation and removal of electrical ... equipment ... for public and private premises, including buildings."[67] 34 Pa. Code § 195(b) also provides that the NEC applies for the installation of wiring. Finally, the Commission has made clear that the NEC pertains to interconnecting inverter-based systems. The standardized form applicants must submit states that per the NEC, an interconnecting inverter-based system must be inspected by an electrical inspector. *Implementation of the Alternative Energy Portfolio Standards Act of 2004: Standard Interconnection Application Forms*, Pa. PUC Docket No. M-00041865 (Feb. 26, 2009), p. L1-9.

The NEC is also clear that the utility side of the meter is under the jurisdictional control of the utility and not the NEC, NEC 90.2(B) ("Not Covered") states: "This Code does not cover … (5) Installations under the exclusive control of an electric utility ... " However, once PPL crosses the line and installs its Devices on the customers' side of the meter – even though PPL owns the Devices – it is subject to the NEC. *See* NEC 90.2(a)(4), which covers: "Installations used by the electric utility, such as office buildings …, and garages."

Thus, the propriety of PPL's method of installation must be examined in terms of PPL's compliance with NEC requirements. And importantly, NEC Section 110.3(B) mandates that "Equipment that is listed, labeled, or both, or identified for a use [] be installed and used in accordance with any instructions included in the listing, labeling, or identification."

[67] *See also Leviton Mfg. Co. v. Fastmac Performance Upgrades, Inc.*, 2014 U.S. Dist. LEXIS 84024 (S.D. N.Y. February 28, 2014) (The NEC requires that all electrical products be "listed" with a Nationally Recognized Testing Laboratory ("NRTL"). Underwriters Laboratories, Inc. ("UL") is an NRTL.

The SolarEdge inverter for residential systems and instructions for installing it and related equipment are UL-certified (Ex. JSP-JB-6SR) by a NRTL, Ex. JSP-JB-6SR, p. 2 of 14, and are contained in SolarEdge's "Installation Guide: SolarEdge Home Hub Inverter Single Phase for North America, Version 1.7." (Ex. JSP-SD-4SR).[68] This Guide explicitly provides instructions for installing <u>communications</u> options, including communications with SolarEdge's monitoring platform, but only for the SolarEdge Energy Bank, a battery, a Backup Interface, a Smart EV Charger, a meter, and an additional Energy Hub inverter. Ex. JSP-SD-4SR, pp. 35, 46, 48, 49, 53. But, as PPL admitted in the Hearing (Hrg. Tr., p. 382), SolarEdge's instructions contain no instructions on installing a third-party device such as PPL's DER Management Device, to the inverter to <u>power</u> the Device. JSP St. No. 7-SR, p. 6; PPL St. No. 12-R, p. 10.

As SolarEdge's instructions do not authorize PPL's method of installation, PPL's method is unauthorized. As PPL's method is not authorized by SolarEdge's instructions, PPL's installations constitute violations of the NEC, and in turn evidence negligence. *See Yocum v. Honold*, 75 Pa. D. & C.2d 764 (Common Pleas Court of Delaware County, 1975).

Being unable to point to SolarEdge's instructions as authorizing its actions, PPL has offered several arguments as to why its method is sound, none of which are credible.

First, PPL sought to tell SolarEdge that "SolarEdge's inverters are able and designed to power connected communications devices using their AC terminals." *See*, *e.g.,* PPL St. No. 2-R, p. 14. However, PPL is seriously in error. PPL has stated it powers its Device by "connect[ing it to the inverter's] AC power terminals," Ex. JSP-WB-7SR, and placing "[t]he neutral and hot power connections … behind the screw for the respective AC leads inside of the inverter to power its Device." Ex. JSP-WB-8SR. First, for clarification purposes: PPL's terminology is erroneous. The

[68] Ex. JSP-SD-4SR was inadvertently designated as HIGHLY CONFIDENTIAL.

terminals to which PPL connects are not "AC power terminals," they are screw terminals designed to hold in place SolarEdge factory wires that SolarEdge connects to the inverter (depicted with the red arrow on Ex. JSP-JB-3SR). They are extremely delicate, and are factory-torqued in a controlled environment in conformance with SolarEdge's factory torque specs. JSP St. No. 7-SR, p. 4. They are not "designed and able to power connected communications."

Terminals that are designed and able to provide power, or "field terminals," are "push-in terminals," located in a wholly separate compartment in the inverter (marked with the green arrow on Ex. JSP-JB-3SR) that permit installation using a screwdriver (i.e., permit a far cruder operation than is involved with SolarEdge's factory-torquing the screw terminals). *Id.*, p. 5.

Thus, PPL is connecting its wires in a part of the inverter that is assembled only in a factory setting, and is a location SolarEdge intends no human touch. JSP St. No. 7, p. 10.[69]

Knowing that the applicable product manual offers no refuge, PPL argues that a different manual – SolarEdge's Guide for Installing SolarEdge's "Commercial Gateway with Cellular Support" – authorizes its method. *See*, *e.g.*, PPL St. No. 2-R, p. 59. But for any number of reasons, that Guide is inapplicable. For example, it provides guidance on installing <u>SolarEdge's Gateway</u> in a <u>Commercial</u> setting, not a third-party "gateway" in a customer's <u>residence</u>. Further, the SolarEdge Gateway only "transfer[s] <u>monitoring data</u> from SolarEdge and non-SolarEdge devices "to the SolarEdge monitoring server ...," Ex. JSP-2D, p. 8. It does not transfer <u>power</u> from a SolarEdge inverter to a third-party management Device. Hearing Ex. JSP-2A, p. 7.

Most importantly, while the Manual does provide instructions on powering the SolarEdge Gateway, the Manual is clear that the power source is external; it is not the inverter. Indeed, in all

[69] PPL provided its own torquing specs to try to show it is following sound practice when it opens and closes this area in which it does not belong. But PPL's torquing specs pertain to the torque to be applied to the Hex screws on the inverters' external covers, not the Phillips "screw terminals" in the inside of the inverter, as was admitted by PPL's expert, H. Landis Floyd, in the Hearing. PPL Ex. AD-19RJ; Hrg. Tr., pp. 301 – 302, 303.

its iterations, the Manual has instructed that to "connect [SolarEdge's gateway] to power, use the supplied power supply," i.e., a wall plug, or "an interchangeable AC plug" that SolarEdge ships to the customer in the same package in which it ships its Commercial Gateway.[70]

In the Hearing, Ms. Dombrowski-Diamond cited an instruction from the Manual as supposed support[71] that states:

> For connecting to power, use the supplied power supply . . . If you use a non-SolarEdge power supply, check that it has 12Vdc/1A output ratings, and that it is certified to UL/CSA/IEC60950-1 2ed standards. Limited Power Source output, NEC class 2."

Again, the "supplied power supply" is the "interchangeable AC plug." *See* JSP St. No. 7-SR, p. 6. The "non-SolarEdge power supply" means a power supply in lieu of the "interchangeable AC plug" provided by SolarEdge, such as an ordinary plug that can be purchased, for example, from Home Depot. Hearing Ex. JB-2D, p. 20. The instruction does not say that the inverter may serve as "a non-SolarEdge power supply" for a third-party's gateway. JSP St. No. 7-SR, p. 7.

PPL has also tried to argue that in "several conversations," PPL informed SolarEdge of its method of connecting to the inverter to power its device "and was told there were no issues." PPL St. No. 2-R, p. 14. In <u>no</u> exchange cited by PPL[72] did SolarEdge ever orally, or in writing, "pre-authorize," approve, provide "prior written consent," or tell PPL that SolarEdge "had no issues" with PPL's connecting its Device to the inverter to power the Device.

PPL's expert, H. Landis Floyd, argued that since SolarEdge's "product listing does not prohibit the use of the terminals used by PPL Electric," than its approved. PPL St. No. 12-R. The JSPs' expert, Bill Brooks, calls this "completely wrong," stating: "[s]ince the NEC does not allow

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[70] *See* V. 1.0 (Hearing Ex. JSP-2A), p. 18; V. 1.1 (Hearing Ex. JSP-2B), pp. 19, 18, V. 1.2 (Hearing Ex. JSP-2C), pp. 19, 18; and V. 1.3 (Hearing Ex. JSP-2D), pp. 19, 18. *See also* JSP St. No. 7, SR, p. 6.
[71] Hearing Ex. JSP-2B, p. 20 (Hrg. Tr., Day 2, p. 356, lines 10 – 14).
[72] *See* Exhibit JSP-AD-5SR, JSP-AD-7SR-A, JSP-AD-7SR-B, PPL Exhibit AD-4R, JSP Exhibit AD-9SR, JSP-AD-11SR, JSP-DF-1SR (PPL Exhibit AD-35R), JSP-DF-3SR, or PPL Exhibit AD-1RJ.

[SolarEdge's] equipment to be used in a way that is not specifically allowed in the instructions, it effectively prohibits the use of the terminals used by PPL Electric." JSP St. No. 14-SR, p. 9. PPL's Device's product listing is irrelevant.

Mr. Floyd argues that the NEC is inapplicable, namely because the "the devices are under the exclusive control of the Company." PPL St. No. 12-R, p. 14. As indicated above, the moment PPL installs equipment in a customer's home, it becomes subject to the NEC. This should just be common sense – we are talking about electrical work being done in peoples' homes; not outside, where PPL might typically work such as on a telephone pole.

PPL offered other arguments, none of which hold. PPL's Device's product listing is irrelevant, but certainly does not authorize its manner of powering. PPL Exhibit AD-4. PPL issued instructions for installing its Device in the SolarEdge inverter to power it (PPL Electric Ex. AD-6, at Step 9, pp. 3 – 4, 9 – 10). However, PPL's Lab is not a Nationally Recognized Test Lab. Hrg. Tr., p. 363, and in any event, PPL's instructions do not trump those of SolarEdge's.

B. PPL's Violations of the NEC Has Also Voided Customers' Warranties

PPL's failure to adhere to SolarEdge's installation instructions is a violation of the NEC. SolarEdge's warranty requires that SolarEdge replace a customer's SolarEdge products, including inverters, if they malfunction or fail under terms and conditions set forth in the warranty. JSP St. No. 7, p. 9. The Warranty will not apply if the Product or any part thereof is, *inter alia*, "[d]amaged as a result of misuse ..., as a result of modifications, alterations or attachments thereto which were not pre-authorized in writing by SolarEdge ….," etc.. Ex. JSP-JB-2, Slide 2.

Although it was PPL's actions that voided the customers' warranties, which means SolarEdge was under no obligation to replace the product, SolarEdge voluntarily did so anyway at its own expense, *see* Ex. JSP-JB-2 (REDACTED), Slides 5 – 13, as PPL's Pilot Program "put [SolarEdge] between a rock and a hard place when it comes to maintaining customer relationships with installers." JSP St. No. 7, p. 11. SolarEdge's inverter replacements to date have cost about $12,530, which figure includes materials and labor but excludes the costs of customer support and shipping. JSP St. No. 7, p. 15; and Ex. JSP-JB-2 (REDACTED AND PUBLIC), Slide 14.

C. PPL's Installations Have Caused at Least 9 Instances of Thermal Damage

On August 22, 2024, SolarEdge was called by an installer who observed smoke coming from a customer's inverter. The smoke is visible on Ex. JSP-JB-2, Slide 6. As a smoking inverter is quite unusual, and as the customer had lost generation, the field team escalated the case to SolarEdge personnel, including SolarEdge's Failure Analysis Engineer, Jacob Geller. Based upon his review of the photographs, Mr. Geller immediately saw PPL's connection to the inverter and concluded that the unauthorized modification caused the thermal damage. JSP St. No. 12-R, p. 8.

Because of the photographs showing PPL's connection, SolarEdge's Code Compliance Officer commenced an inquiry into whether other like instances had occurred in PPL territory. That effort yielded the package referred to as the September 19, 2024 PPL Case Review, showing evidence of 8 instances of thermal damage to inverters that have or had PPL's Device installed. *Id*. at pp. 8-9.

Based on photographs and field service tech reports (JSP St. No. 13-SR, p. 4), the exact same type of evidence relied upon by PPL's expert, Mr. Floyd (Hrg. Tr., pp. 241-242), Mr. Geller testified:

> In my opinion, in <u>all</u> 8 cases we had clear evidence of thermal damage to the inverters, all of which have or had PPL's device installed. The ability to identify causation varies, but it is clear that in each case, the thermal damage arose from PPL's installations reducing spacing; over-torquing, cross-threading, or not sufficiently tightening screws; leaving behind contamination; or leaving bare wire exposed and in contact or in proximity with the circuit board, all of which could cause thermal arcing. Or, the thermal damage arose as a result if the installer causing mechanical damage to components during installation, which can also cause thermal damage.

JSP St. No. 13-SR, p. 4 (stating he performed a "root cause" analysis). Mr. Geller also subsequently supervised an experiment in the SolarEdge laboratory that showed that a loose screw that was hand-tightened would cause the type of thermal damage seen in the PPL case review. JSP St. No. 13-SR, p. 7; Ex. JSP-JIG-13SR.

Not surprisingly, PPL disputes each of Mr. Geller's conclusions.

Regarding Case 5081942 (Ex. JSP-JB-2 (REDACTED)), Ms. Dombrowski-Diamond argues "the inverter was already having issues before the Device was installed," but cannot answer whether the purported pre-installation discoloration was not simply residue flux. Hrg. Tr. p. 377. She asserts also in her Rejoinder Testimony regarding that it and Case 47085589, without providing any documents showing any measurement, that SolarEdge's manufacturing "encroach[ed] on the 5 mm NEC requirement." PPL St. No. 2-RJ, pp. 49, 51. NEC 2017 110.3 permits manufacturers to comply with NEC ***or*** NRTL-approved instructions included in the listing or labeling. PPL offered no evidence that SolarEdge's manufacturing did not meet its manufacturing requirements.

Regarding Case 471544, *Id*., she concedes the varistor is cracked (which Mr. Geller cites as the cause of the damage), but speculates, again without citing measurements, that the damage resulted from SolarEdge's not adhering to a wire strip length requirement that she, without support, asserts governs, PPL St. No. 2-RJ, p. 53, but in the Hearing, concedes she is unaware if it meets SolarEdge requirements. PPL St. No. 2-RJ, p. 50. Regarding Case 4705589, *Id*., she blames a third party for improperly installing PPL's Device, Hrg. Tr., p. 380, although PPL's Tariff reserves to it exclusive right to install its Device. PPL Ex. SS-2, Tariff Sec. C.(3).

Regarding Case 4458739, *Id*., Ms. Dombrowski-Diamond asserts that due to the "known hardware issue" [discussed below], it is reasonable to conclude that the failure point was SolarEdge's component, not PPL's wire stripping, as asserted by Mr. Geller. JSP St. No. 13-SR, p. 8. PPL's initially-produced Installation Instructions said nothing about wire stripping length, JSP St. No. 13-SR, p. 8, but later produced in her Rejoinder, Ms. Dombrowski-Diamond provides instructions specifying a wire strip length. *Id*., 9. But in her testimony and in the Hearing, fails to provide support for her assertion as to the length of the wire, and that the instructions to which she claims to have adhered comport with SolarEdge's. Hrg. Tr., p. 382.

Regarding Case 4141508, PPL quotes Mr. Geller's statement he "could not draw a conclusion," but fails to quote the rest of the sentence ("I … could not draw a conclusion … as the thermal damage was too catastrophic for me to pinpoint the starting location"); and disregards his second sentence ("I can attest though that the source area is with PPL's AC connection…"). JSP St. No. 13-SR, p. 9.

Regarding Case 3456467, in Rejoinder Testimony, PPL correctly noted that Mr. Geller's Exhibit JSP-JIG-8SR was of a different inverter. The JSPs' review reveals that all the photographs PPL produced purporting to show the before- and after-installation conditions at "Case 3456467" were all of the erroneous inverter. Nevertheless, the JSPs maintain the portion of Mr. Geller's testimony finding that the photographs document both signs of thermal damage, and disconnection of PPL's Device. Regarding Case 4065702, Slide 12, PPL disregarded Mr. Geller's opinion re the damage to the varistor, and the reduced spacing. JSP St. No. 13-SR, p. 9.

During discovery, PPL informed the JSPs of a ninth instance of thermal damage. *See* JSP St. No. 13-SR, Section III. PPL asserts SolarEdge conceded the damage was caused by a "known SolarEdge hardware error," but documents produced by both PPL and the JSPs do not so state. Further, SolarEdge's records showed that the thermal event PPL observed in February, 2023, could not have been caused by a hardware error displayed in June, 2022. JSP St. No. 12-SR, p. 6.

In his Rejoinder Testimony, for the first time (depriving the JSPs of an opportunity to respond), Mr. Floyd asserts that the fact that components are insulated makes spacing between them irrelevant, PPL St. No. 12-RJ, pp. 9-10, effectively conceding that PPL failed to employ appropriate spacing protocols. Mr. Geller opined, however, that reduced spacing increases the likelihood of arcing as does modifying equipment in unauthorized ways. JSP St. No. 13-SR, p. 12.

V. REQUESTED RELIEF

Based upon the foregoing, the JSPs respectfully request that the Commission:

- Bar PPL from requiring that inverters be tested for compatibility with PPL's Device;

-Deny the Petition, although PPL may continue to require smart inverter settings that provide voltage regulation via autonomous functions, or

-If the PUC chooses not to deny approval, then make the Program voluntary, and its requirements and testing applicable only to voluntarily participating DERs; and

-Order PPL to immediately cease connecting to SolarEdge inverters to power its Devices, and replace SolarEdge inverters in which it has installed its Device, or pay $2 million into a fund for replacements of inverters with PPL's Devices installed and thermal damage.

Respectfully submitted,

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PROPOSED FINDINGS OF FACT - PUBLIC

I. Background on the Joint Solar Parties

1. The JSPs are an ad hoc group of entities, all of whom are in the business of installing solar energy and battery storage equipment, manufacturing said equipment, or providing grid services via aggregation of said equipment, or are a trade association representing same.

2. SEIA is the national trade association for the solar and storage industries, with more than 1,200 member companies, including most of the JSPs, and other partners who do business in Pennsylvania, including in PPL territory. Joint Solar Parties Statement ("JSP St.") 1, p. 1.

3. AHC is a $30 million/year company that presently does business in nine states, including Pennsylvania, and is finalizing its involvement in a tenth state. JSP St. 2, p. 1.

4. Sun Directed, a family-owned business founded 16 years ago and employing 11 in Pennsylvania, JSP St. 3, p. 2, has installed 400+ solar and solar+storage projects in Central Pennsylvania. JSP St. 3, p. 1.

5. Trinity is one of the largest, independently owned solar installation companies in the United States, JSP St. No. 5, p. 2, that over the last 30 years, has provided solar power and roofing solutions to more than 100,000 homeowners in the mid-Atlantic and Northeast, including 12,000 solar or solar + storage systems in Pennsylvania, over 1,700 of which in 2023 alone were in PPL territory. JSP St. No. 5, p. 2.

6. Green Way Solar is not a JSP member but filed initial and Surrebuttal testimony on the JSPs' behalf, due to its dissatisfaction with PPLs' Pilot Program. JSP St. No. 10, p. 2. Green Way has been installing solar systems on residences and businesses in central and

eastern Pennsylvania since 2018. Roughly 60 percent of its projects are in PPL territory. *Id*.

7. Tesla is a manufacturer and installer of battery energy storage and solar systems, and is a leading participant in programs in which Tesla aggregates residential battery energy storage systems and facilitates customers being compensated for grid services such as generation capacity and ancillary services. Tesla has installed roughly 453,000 residential solar systems across the country with project designs similar to those discussed in this proceeding before it ceased doing new business in PPL territory. JSP St. No. 4, p. 17. As of December, 2023, Tesla or third parties had installed nearly 800 Powerwall battery energy storage units in PPL territory. JSP St. No. 8, p. 3. Over 95,000 Tesla Powerwall residential battery energy systems amounting to more than 500 MW of installed nameplate capacity are enrolled in more than 50 Virtual Power Plants ("VPPs"), including utility-level programs, as well as aggregations participating in wholesale electricity markets. *Id*. at 5.

8. Enphase is a global energy technology company and leading manufacturer of solar microinverters, battery energy storage, electric vehicle supply equipment and home energy management systems that optimize the use of locally produced solar energy to power homes and provide grid services. JSP St. No. 6, p. 2. Enphase also provides third-party aggregator grid services in demand response and VPP programs across the United States and in Europe, working with utilities, grid operators, third party DERMS providers, retail electric providers and homeowners to help utilities and retailers avoid the need to purchase power, in exchange for providing customers compensation that offsets the costs

of their DER purchases or reflects the customers' performance in grid services events. JSP St. No. 6, pp. 19 - 20.

9. SolarEdge is a Delaware corporation registered to do business in Pennsylvania with headquarters in Israel. SolarEdge is also an aggregator, providing grid services in exchange for compensation, such as generation, demand response, ancillary services, balancing services, voltage or frequency regulation, or other services, in response to utility-level signals or in response to wholesale electricity market opportunities. JSP St. No. 7, p 16.

II. Procedural History

10. On May 20, 2024, PPL filed its Petition requesting that the Pennsylvania Public Utility Commission ("Commission") approve tariff modifications and other authorizations needed to implement PPL's Second DER Management Plan pursuant to Paragraph 62 of the Joint Petition for Settlement of All Issues approved by the Commission at Docket No. P-2019-3010128.

11. PPL served its Petition on counsel for AHC, SEIA, Tesla and Sunrun, Inc. ("Sunrun"), a group of entities then also referred to as "Joint Solar Parties" in Docket No. P-2019-3010128. May 20, 2024 Letter from Devin Ryan, Post Schell, to Secretary Chiavetta, enclosing Petition.

12. On July 8, 2024, the entities referred to as "Joint Solar Parties" in this docket -- AHC, SEIA, Tesla, Enphase, SolarEdge, Sun Directed, Trinity, and Sunnova, Inc. ("Sunnova"), filed an Answer, Protest, and Petition to Intervene in this docket, the latter of which was granted on August 6, 2024. Sunnova withdrew on September 13, 2024. Briefing Order issued by Administrative Law Judge John M. Coogan, n. 1.

III. Details Of PPL's Program

13. In Docket No. P-2019-3010128, PPL obtained approval to conduct a three-year Pilot Program (PPL St. No. 7, p. 4) through March 21, 2025. By Order dated September 12, 2024, the Pilot's term was extended until thirty days after the Final Order is entered in this docket.

14. As of January 1, 2021, PPL's Pilot Program required that new DERs interconnecting with PPL's distribution system use smart inverters installed in the customer's DER and approved by PPL as meeting UL 1741 Supplement A ("SA"); and PPL's testing for the communications requirements under IEEE 1547-2018 (the "Interim Requirements") – which requirements PPL obtained approval to "proactively implement" in anticipation of UL 1741 Supplement B ("SB") becoming effective. PPL St. No. 1, pp. 8, 12.

15. Since January 1, 2023, PPL's Pilot Program has required that new DERs interconnecting with PPL's distribution system use smart inverters approved by PPL as meeting IEEE 1547-2018, and certified to UL 1741 SB using IEEE 1547.1-2020, PPL St. No. 1, p. 12, and meet PPL's DER Lab's testing requirements "to ensure that [the inverters] are compatible with PPL Electric's DER Management Devices …" *Id.*, pp. 12 – 13.

16. IEEE 1547-2018, a consensus-based standard developed by the Institute of Electrical and Electronics Engineers ("IEEE"), provides the technical specifications for interconnection and interoperability between DERs and utility electric distribution grids. JSP St. No. 9, p. 4; 1547-2018 Abstract.[1]

17. Per the standard, IEEE 15471-2018's purpose is as follows:

> There is a critical need to have a single document of consensus standard technical requirements for DER interconnection rather than having to conform to numerous local practices and guidelines. This standard addresses that critical need by providing uniform

[1] For convenience, a publicly available version of IEEE Std 1547™-2018 is appended hereto.

criteria and requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection."

IEEE 1547-2018, Introduction, p. 10.

18. IEEE 1547-2018 defines "interoperability" as "[t]he capability of two or more networks, systems, devices, applications, or components to externally exchange and readily use information securely and effectively." IEEE-1547-2018, 3.1.

19. IEEE 1547-2018's Abstract states: "The technical specifications for, and testing of, the interconnection and interoperability between utility electric power systems (EPSs) and distributed energy resources (DERs) are the focus of this standard. It provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection." *See*,1547-2018, p. 2.

20. IEEE 1547.1-2020[2] (IEEE's Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces) provides the nationally applicable testing requirements for how DER systems or equipment conform to the requirements of 1547-2018. JSP St. No. 9, p. 4.

21. UL 1741 Supplement B ("SB") (approved March 5, 2020) provides the official industry standard for Nationally Recognized Testing Labs ("NRTLs'") to verify that the inverter meets the interoperability conformance test procedures set forth in IEEE 1547.1-2020 (approved March 5, 2020) (PPL St. No. 4, p. 6).

[2] IEEE 1547.1-2020 is subject to copyright, available only for purchase.

22. A NRTL is "recognized [by the U.S. Department of Labor's Occupational Safety and Health Administration ("OSHA")] as meeting the requirements in 29 C.F.R. 1910.7 to perform testing and certification of products using consensus-based test standards."[3]

23. 52 Pa. Code § 75.22 also defines a NRTL as "A qualified private organization that meets the requirements of the Occupational Safety and Health Administration's (OSHA) regulations. NRTLs perform independent safety testing and product certification. Each NRTL must meet the requirements as set forth by OSHA in the NRTL program."

24. Per UL 1741 SB (SB 4.3.6.1), the interoperability conformance tests can be met through use of several communications protocols, which are used to store or send information and to control adjustable inverter functions, either IEEE 2030.5, SunSpec Modbus, or DNP3. [MISSING] JSP St. No. 9, p. 4.

25. IEEE 2030.5 provides support for monitoring and control of DER devices. The standard defines the mechanisms for exchanging application messages, the exact messages exchanged including error messages, and the security features used to protect the application messages. IEEE 1547-2018, Annex 2, Clause D.3.2

26. The SunSpec Alliance specifies standard Modbus-based information to support monitoring and control of the DER devices. IEEE 1547-2018, Annex 2, Clause D.3.4.

27. IEEE Std 1815™ is the IEEE Standard for Electric Power Systems Communications-Distributed Network Protocol (DNP3). 1547-2018, p. 20.

28. IEEE 1815 is used to interface to DER devices, often used by utility supervisory control and data acquisition ("SCADA") systems. IEEE 1547-2018 Annex 2, Clause D.3.3., p. 111.

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[3] *See* https://www.osha.gov/nationally-recognized-testing-laboratory-program/frequently-asked-questions#employers_regulators.

29. IEEE 1547.1 does not require certification by these protocol developers, such as SunSpec Certified™ or to any developer-produced test protocols, such as the SunSpec Modbus Conformance Test Procedures.

30. That an inverter is "suitable" for use is evidenced by its "listing" or "labeling," 29 C.F.R. § 1910.303(b)(1)(i), which involves inspection and approval by the NRTL using "appropriate test standards approved by OSHA." 29 C.F.R. § 1910.399; 1910.7(b)(1)(i), (c).

31. PPL's Devices contain an Advanced Metering Infrastructure ("AMI") radio, or cellular modem, that connects to the DER's local communication interface and enables PPL's monitoring and management of the DER. PPL Ex. SS-1, p. 7.

32. PPL relies or relied on three different DER Management Devices: the Smart Collar and Dongle; the Bridge; and the Cellular Gateway. PPL St. No. 1, p. 25. The Smart Collar and Dongle Device was PPL's first-generation Device and has been replaced by the Bridge Device. The Bridge and Smart Collar and Dongle Devices use the existing AMI work. The Cellular Gateway is used for IEEE 2030.5 inverters. PPL St. No. 2, p. 4.

33. A local DER communication interface is "a local interface capable of communicating to support the information exchange requirements specified in this standard for all applicable functions that are supported in the DER." IEEE 1547-2018, Section 3.1.

34. IEEE 1547-2018 defines an interface as "[a]n electrical or logical connection from one entity to another that supports one or more energy or data flows implemented with one or more power or data links."

35. PPL's DER Lab testing "to ensure that [the inverters] are compatible with PPL Electric's DER Management Devices …"involves PPL's " ... DER Lab verif[ying that] the inverter

has the ability to read and write to the Modbus registers or via the 2030.5 interface, an open and available port, and the ability to monitor and manage the DER regardless of the number of inverters networked."   PPL St. No. 2-R, p. 19.

36. PPL's DER Lab is not a NRTL. Hrg. Tr., pp. 362 – 363.

IV. PPL's Program and IEEE

a. PPL's Compatibility Testing Exceeds IEEE Requirements

37. 52 Pa. Code § 75.22 requires interconnecting DERs to be certified to meet "(i) IEEE Standard 1547, 'standard for Interconnecting Distributed Resources with Electric Power Systems,' as amended and supplemented," and "(ii) UL Standard 1741, 'Inverters, Converters and Controllers for use in Independent Power Systems' (January, 2011), as amended and supplemented."

38. PPL's DER Lab Testing requirements "to ensure that [the inverters] are compatible with PPL Electric's DER Management Devices .... " PPL St. No. 2-R, p. 19.

39. In short, PPL's DER Lab is testing to ensure that inverters meet IEEE 1547's interoperability requirements. *See* PPL St. No. 4, p. 15, stating: "Most significantly, [PPL's] Plans integrate DERs into a cohesive and coordinated system management architecture by utilizing real-time management of DER grid-support function parameters and increasing visibility of DER operations using the data interoperability requirements of [IEEE 1547-2018].

40. No utility in the country has "implemented anything on par with the Company's First DER Management Plan or Second DER Management Plan." *See* PPL St. No. 6, p. 16, where PPL witness Elizabeth Cook states: "Although utilities have implemented many components and requirements for inverter requirements, such as IEEE and other industry

driven initiatives (like communication protocol requirements), other utilities have not yet taken the next step of leveraging them to monitor and manage DERs across the distribution system."

41. The Electric Power Research Institute ("EPRI"), as well as industry experts including PPL, have identified 26 gaps in the "interoperability" portion of IEEE 1547-2018. (JSP St. No. 9, pp. 6-7).

42. PPL provided a list of gaps to EPRI that PPL discovered when it was testing inverters in its DER Lab for compatibility with its Device. PPL St. No. 2-R, p. 7; PPL Ex. AD-2R.

43. The fact of "gaps" in the interoperability portion of the IEEE standard means that PPL can be interpreting the standards differently than are the inverter manufacturers or the NRTLs that certified the inverters as meeting the required standards. PPL St. No. 2-R, p. 7.

44. For example, PPL's Program mandates that "inverters or inverter control modules using Modbus TCP communications shall set inverters to have static IP address(es)." Exhibit JSP-BL-2SR.

45. However, EPRI Issue #26 states: "IEEE-1547-2018 is silent regarding how this IP address is assigned. DER manufacturers are utilizing a variety of methods to assign the IP address, including static and dynamic/DNS assignments." Exhibit JSP-BL-3SR.

46. An inverter that has been certified by an NRTL as meeting IEEE 1547-2018 and UL 1741 SB standards but that does not meet PPL's "interoperability" requirements may be denied permission to interconnect. PPL St. No. 2-R, p. 6.

47. No other U.S. utility requires that DERs be tested for compatibility with a utility-owned DER Management Device in order to receive approval to interconnect. JSP St. No. 9, p. 6.

48. PPL's Expert testified: "In the case of Modbus RTU devices, PPL Electric included two requirements that some have argued were outside the scope of IEEE 1547-2018 and UL 1741 SB: (a) the ability to support broadcast mode and (b) the ability to adjust device addresses." PPL St. No. 5-RJ, p. 5.

49. An adjustable Modbus/RTU address means each inverter in a multi-inverter network can have a unique address, or ID, from 1 – 247.

50. Both of the above-identified issues (¶ 48(a) and (b)) were addressed by SunSpec in June 2024, when SunSpec Modbus issued its Modbus Conformance Test Procedures version 1.2 to require that inverters SunSpec certified after June, 2024 support adjustable Modbus/RTU addresses. PPL St. No. 5-RJ, p. 6; Hrg. Tr. p. 133. These test specifications were finally approved in October, 2024. *see* https://sunspec.org/modbus-specification-updates/.

51. IEEE 1547, 1547.1 and UL 1741 do not require local DER communication interfaces to be SunSpec certified.

52. Inverters certified before June, 2024, whether or not they are SunSpec certified, retain their UL 1741 certification but may not meet PPL's requirement that inverters using SunSpec Modbus have an adjustable Modbus RTU device address. Hrg. Tr., p. 187.

53. PPL has limited inverters that are certified to UL 1741 SB but unable to adjust serial device addresses to single inverter installs. Hrg. Tr. p. 188.

54. In order to be approved for use in PPL territory, PPL's Program requires, *inter alia*, that inverters "have a network system and be able to communicate to inverters along the chain with a mod ID of two plus"). PPL St. No. 2-R, p. 24; Hrg. Tr. p. 342

55. PPL's webpage containing its "Smart Inverters and DER Pilot Management Requirements" (Updated 2/17/2025) provides:

Inverter-based DER installations where more than one inverter is installed at a premise require that the inverters are networked together as part of the installation. Inverters shall be networked together such that all applicable inverters can accept commands from the Company-owned DER Management Device connected to a port earmarked and labeled for use by PPL.

56. PPL's FAQ page states:

"**Why does PPL Electric require me to network my inverters?**

As part of our DER Management Pilot Program requirements, PPL Electric is permitted to install a limited number of management devices per calendar year. To prevent the installation of multiple management devices and to keep installations as aesthetically viable as possible, we require networking of all inverters which are part of a single application submission. This allows PPL to expand our Pilot Program to encompass as many of our customers as possible, while at the same time keeping the amount of utility equipment required for your installation to a minimum.

57. IEEE 1547-2018 Section 10.1 requires that a DER have provisions for a local interface but does not specify the numbers of interfaces that must be capable of communicating.

58. IEEE 1547-2018, Section 1.4, does not require that inverters be networked. It states:

This standard does not determine the communication network specifics, nor the utilization of the DER provisions for a local DER interface capable of communicating (*local DER communication interface*) to support the information exchange requirements specified in this standard.

59. IEEE 1547-2018 defines "interoperability" as "a capability which may be met by two or more networks." It does not require that two or more inverters be networked to be interoperable.

60. PPL has limited the use of 41 inverter models from 6 manufacturers to single-inverter projects because "those inverters cannot have a network system" and are unable to communicate to other inverters "in a stream," although the inverters were NRTL-certified as meeting the IEEE 1547-2018 standard. Hrg. Tr., pp. 342 – 343. *See* PPL Approved Inverter List, on which certain inverters are flagged in red as being limited to "One … Inverter per Application."

61. In June 2024, SunSpec issued a certification specification that requires an adjustable Modbus RTU device address. PPL St. No. 5-RJ, p. 4.

62. IEEE 1547.1 does not require certification by these protocol developers to any developer-produced test protocols, such as the SunSpec Modbus Conformance Test Procedures.

b. IEEE Defers to the Commission to Determine Questions of Control over Reactive Power

63. A stated purpose of PPL's Program was to facilitate PPL's monitoring of real power, reactive power and voltage (PPL St. No. 3, pp. 13).

64. SolarEdge participated in a utility program in which SolarEdge provided the service of improving power quality by remotely updating customers' reactive power control settings to absorb or generate reactive power when the grid voltage was outside a predefined range. Customers were offered a flat fee for enrolling, more for staying in the program, and additional compensation when SolarEdge's manipulation of the customer's reactive power did in fact interfere with the customer's generation of real power. JSP St. No. 7, pp. 20 – 21; JSP St. No. 7-SR, p. 18; Ex. JB-21SR.

65. SolarEdge testified that: " ... the DER designer[does not typically] design[] an inverter that is large enough to produce sufficient reactive and active power to meet PPL's needs

as well as the customer's interest in real power. In commercial settings, certainly, a larger customer may spend more on an inverter that is big enough to meet both sets of obligations." JSP St. No. 7-SR, p. 21.

66. Tesla testified that: "it is possible to design inverters in a more expensive way such that they can provide reactive power support without sacrificing real power. However, to my knowledge, it is not typical of manufacturers of residential system inverters to design their inverters this way, because it requires inverter manufacturers to oversize the inverter's capacity, list the inverter at a lower nameplate capacity, and reserve a portion of the inverter capacity at all times to sit idly until it can be used to provide reactive power. JSP St. No. 8-SR, p. 6.

67. The SolarEdge witness testified: Doing so "would risk increasing the inverter's price and making it less competitive, especially in the residential market." JSP St. No. 8-SR, pp. 6 – 7.

68. IEEE 1547-2018, Section 1.4, states: " . . . it is the responsibility of the *authority governing interconnection requirements* (AGIR) to determine the applicability . . . of performance categories related to reactive power capability and voltage regulation performance requirements . . . "

69. IEEE 1547-2018, Section 1.4, n. 12, states: "The impact of DER on frequency and voltage performance of the interconnections and the regional power systems differs significantly, and it remains the responsibility of an AGIR to quantify impactful DER penetration levels."

c. IEEE Addresses Anti-Islanding

70. PPL claims its control of customers' inverters is required to use remote on/off functions on battery storage or solar systems that have not safely isolated, or "islanded" from the distribution system. Petition, p. 15.

71. In addition to claiming that its program focus is on managing reactive power, PPL argues its control of customers' inverters is required so it may use the remote on/off functions on battery storage or solar systems that have not safely isolated, or "islanded" from the distribution system. Petition, p. 15.

72. Pertaining to its anti-islanding objective, PPL cites an NREL Primer that states that "increasing DER penetration and deployments of different types of inverters can increase the likelihood of unintentional islands." PPL St. No. 3, p. 56, *citing* D. Narang, et al., NREL/TP-5D00-77782, April, 2022, *A Primer on the Unintentional Islanding Protection Requirement in IEEE Std 1547-2018* ("NREL Primer") (a copy of which is appended).

73. The NREL Primer, a copy of which is attached hereto states "High-penetration scenarios. Studies have shown that the speed of anti-islanding detection could decrease as the numbers of inverters in the island increases . . . " NREL, p. 22.

74. PPL has "not yet" accessed the remote on/off capability it gave itself. PPL St. No. 3, p. 55.

75. PPL's Expert Cody Davis testified that out of the numerous outage events PPL observed that impacted actively managed DERs, none caused an unintentional islanding event. PPL St. No. 3, pp. 55 - 56.

76. The Commission has noted that anti-islanding capability is already built into inverter-based systems certified to IEEE 1574 standards and tested in accordance with UL 1741.[4]

77. IEEE 1547-2018 states . . . that a local DER interface must be capable of communicating, but does not state that the interface shall be always used by the utility for such purpose.

d. IEEE Defers Questions of Control to the Commission

78. IEEE 1547-2018, n. 2 states: "it remains in the responsibility of an AGIR to quantify impactful DER penetration levels."

79. The … IEEE 1547.2-2023 Guide[,] which provides technical background and guidance to support understanding of IEEE 1547-2018, states that: "IEEE Std 1547-2018 does not assume a specific use case or application . . . This standard does not address planning, designing, operating, or maintaining the Area EPS with DER."

V. PPL Fails to Show its Program is Reasonable, Just, or in the Public Interest

a. PPL Fails to Show its Extreme Program is Necessary at this Time

80. PPL claims its Plan will assist it in "proactively preparing for increasing DER interconnections," PPL St. No. 1, p. 28, chiefly, by "increase[ing] hosting capacity for additional DERs at far lower cost than the available alternative." PPL St. No. 1-R, p. 15.

81. "Hosting capacity" is the amount of [distributed photovoltaic systems] ("DPV") that can be added to distribution system before control changes or system upgrades are required to safely and reliably integrate additional DPV. Petition, n. 2.

[4] Pa. PUC Docket No. L-00050175, *Final Rulemaking Re Interconnection Standards for Customer-generators pursuant to Section 5 of the Alternative Energy Portfolio Standards Act, 73 P.S. § 1648.5; Implementation of the Alternative Energy Portfolio Standards Act of 2004: Interconnection Standards,* August 17, 2006, p. 9.

82. PPL also claims its Plan will assist it in "proactively tackling issues presented by DERs, rather than invest in costly distribution system upgrades to resolve those issues." *Id*. at 34.

83. PPL has very low rates of solar penetration (only 3.94% of peak capacity in PPL territory 270.641 MW), as compared with Vermont's (32%), or San Diego's (43%)). JSP St. No. 1, pp. 10, 19 - 20.

84. PPL's Device has a 15-year book-life. PPL St. No. 10-R, p. 5.

85. DERs installed today "are expected to remain connected to the PPL Electric System for decades." PPL St. No. 4-R, p. 14.

86. A study by Deloitte cited by PPL states that ". . . residential capacity could grow . . . " by 2035. PPL St. No. 1-R, p. 47; PPL St. No. 1-RJ, p. 13.

87. Hawaiian Electric is projected to have over 2,086 MW of solar on its system by 2045. [5]

88. Hawaiian Electric's grid modernization strategy includes the creation of custom smart inverter setting profiles, grid modernization investments, ". . . equitable cost allocation and compensation for customers and other non-utility service providers who both provide and receive grid services." JSP St. No. 1-SR, p. 17.

89. Utility programs that have piloted active utility control and shown that such control can provide benefits, PPL St. No. 7-R, p. 5, *citing* JSP St. No. 1, p. 24, have provided compensation to DER owners for their provision of grid services, have been fully voluntary, and have provided customers with the ability to use software to manage their

[5] Hawaiian Electric, Maui Electric, Hawai'i Electric Light, Modernizing Hawai'i's Grid for Our Customers, August 29, 2017, *available at:* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/grid_modernization/final_august_2017_grid_modernization_strategy.pdf , p. 3 (*cited in* JSP St. No. 1-SR, p. 17).

DERs, rather than having to install a utility-owned management device in their inverters.[6, 7]

90. PPL has not sought to identify a level of enrollment that would achieve its program objectives. *See* Ex. JSP-NZ-1SR, PPL's response to an Office of Consumer Affairs Discovery Request.

91. PPL's Pilot Program capped the number of Device installs at 3,000/year, PPL St. No. 1, p. 13, and excluded from Pilot requirements members of control groups whose DER inverters operated instead under autonomous settings only, PPL St. No. 1, p. 14, and members in a Grandfathered Group. PPL St. No. 1, p. 3.

92. PPL's Second Plan would apply to all new DERs, as well as to all the DER's in the Pilot Program's control groups, to all systems interconnected before the Pilot Program started on January 1, 2021, and to all inverter-based DERs interconnected after the Pilot Program started without Devices installed; and would remove the Pilot Program's 3,000 Devices/year cap. PPL St. No. 1, pp. 22 - 23. Previously excluded customer-generators would be required to submit a new interconnection application when they upgrade their system, install a new inverter on their system, or by March 22, 2040, whichever is earlier. PPL St. No. 1, n. 3

93. As of the date of its Petition, PPL had 26,243 customer- and third-party -owned DERs on its system, 11,841 of which interconnected during the Pilot Program. PPL St. No, 1, pp. 25, 11. Of the 11,841 customers, 7,418 were included in the program and have a

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[6] JSP St. No. 1-SR, p. 5, *citing* Ex. JSP-JW-2SR ("California Energy Commission, Energy Research and Development Division, Final Project Report, Electric Access System Enhancement, Assessment of a Distributed Energy Resource Management System for Enabling Dynamic Hosting Capacity, June 2024; CEC-500-2024-064), p. 14.

[7] *See also* Office of Consumer Affairs ("OCA") St. No. 1, p. 30, *citing* San Diego and Massachusetts' ConnectedSolutions.

Device installed, while 4,423 DERs were grandfathered because of the annual cap, or because there were no Devices available that were compatible with those DERs at the time of interconnection. PPL St. No. 2, p. 11.

94. PPL has not explored whether provision of compensation to customers would incentivize enrollment in a program. PPL St. No. 1R, p. 1

95. The DER owners own the DERs that provide reactive power support functions and monitoring capabilities. JSP St. No. 6-SR.

96. Incentives can help putative DER owners defray the costs of their purchasing DERs. JSP St. No. 4, p. 13.

97. Customers might need to pay more for inverters large enough to both generate enough real power to meet their needs, as well as reactive power to meet PPL's needs. JSP St. No. 7-SR, p. 19. JSP St. No. 7-SR, p. 19.

98. The DERs are providing a grid service insofar as the voltage violations the DERs are resolving are remote from the point of interconnection. *See* JSP St. No. 9, p. 10, and Exhibit JSP-MM-1SR (PPL's discovery response).

99. PPL does not know the root cause of the voltage violations the DERs are resolving. JSP St. No. 9, p. 10, and Exhibit JSP-MM-1SR (a PPL discovery response).

100. PPL claimed in its 2024 DER Management Report that active management of DERs avoided over 23,000 voltage violations that could have resulted in truck rolls, saving over $13.6 million dollars, PPL St. No. 3, p. 48.

b. PPL Has Failed to Show the Costs of its Program are Reasonable

i. Mr. Wishart's Cost/Benefit Analysis Contains Significant Flaws

101. In its 2024 DER Management Report, PPL claimed that avoided truck rolls produced the majority of program benefits, amounting to roughly 62% of PPL's claimed benefits of its program. PPL Electric Exhibit CD-4, p. 19 (which attributes $13.66 million to avoided truck rolls, and p. 1 lists $21.93 in total benefits to date).

102. PPL's 2024 DER Management Report found that the benefit from avoided truck rolls alone was more than double the roughly $6.5 million in program costs to date at that time (PPL's calculations show avoided benefits as 2.09 times higher than program costs). *See*, PPL Ex. CD-4, at p. 1.

103. The approach employed by PPL Rebuttal Expert Witness, Steven Wishart " ... to estimating avoided truck rolls ... result[ed] in a much lower estimate" than the one set forth in PPL's Petition. PPL St. No. 10-R, p. 18.

104. Mr. Wishart estimated 172 avoided truck rolls associated with 10,000 DER Management Devices in 2025, PPL St. No. 10-R, p. 29, roughly 75 times less than what PPL estimated in it 2024 DER Management Report, and reduced the benefits from avoided truck rolls to only 5 percent of the total program benefits and only 11.4% of program costs. PPL St. No. 10-R, at 9.

105. In its Petition, PPL identified 29 MW of new hosting capacity resulting from monitoring DER production, active management of power factor, and use of smart inverter settings PPL St. No. 10-R, pp. 15 – 16. If fully utilized, PPL claimed the hosting capacity would have produced additional generation, and reduced distribution and transmission losses valued at approximately $4.57 million, amounting to roughly 21% of the roughly $21.9 million in benefits that PPL claimed under the Pilot. *See*, PPL Ex. CD-4, at p. 1.

106. On Rebuttal, Mr. Wishart identified that 85.9% of the Program's benefits would come from "incremental hosting capacity" created by the program, PPL St. No. 10-R, Table SWW-6, JSP St. No. 4-SR, p. 26, PPL St. No. 1-R, p. 5, PPL St. No. 10-R, p. 9.

107. Mr. Wishart assumed that the 258 MW of "incremental" roughly 5,731 MW of solar to be installed between 2025-30 (*see* PPL's Answer to OCA-II-6) in Pennsylvania. JSP St. No. 4-SR, p. 27 (*citing*) PPL's Answer to OCA-II-6.

108. The Pennsylvania Department of Environmental Protection's ("PaDEP's") Solar Future Plan, Ex. JSP-JG-13SR, sets a target for the amount of solar PaDEP recommends be achieved by 2030 (10% of energy consumed), 2,500 MW of which is projected to come from distributed generation, an amount that is 57 percent lower than that assumed by Mr. Wishart. JSP St. No. 4SR, p. 27, *citing* Ex. JSP-JG-13SR.

109. A PPL internal Draft DER Forecasting Paper lacks definitive territory-wide projections, and fails to account for projections from other solar industry publications. JSP St. No. 4-SR, p. 28.

110. Mr. Wishart's estimate of the savings attributable to 258 MW of "incremental" hosting capacity is flawed because he likely double-counted some or all of the components comprising the benefits he ascribes to the increased "incremental" hosting capacity resulting from the program. Hrg. Tr., pp. 212 - 215.

111. Mr. Wishart estimates that 258 MW of "incremental" hosting capacity will save $61.3 million from "Avoided Distribution Infrastructure Investments" and $64.6 million from "Avoided Energy from Incremental Hosting Capacity." PPL St. No. 10-R, p. 9, Table SWW-2.

112. As described and calculated under PPL's Second Plan, no DER can claim both avoided infrastructure investments and avoided energy costs.

113. Mr. Wishart's analysis fails to distinguish the proportion of the benefits associated with Avoided Distribution Infrastructure Investments that would flow to ratepayers, from that that would flow to the owners of interconnected DERs, who typically pay the costs of grid upgrades associated with interconnection. JSP St. No. 4-SR, p. 28; PPL St. No. 10-RJ, p. 22; Hrg. Tr. p. 206.

114. Subtracting the roughly $61.3 million of projected benefits that are double counted, the program's benefit-to-cost ratio falls to 1.05 (from the 1.8 ratio that Mr. Wishart calculated), if *all* of Mr. Wishart's other projections also hold true.

115. If none of these hosting capacity benefits materialize, the benefits-to-cost ratio falls to 0.25.

ii. PPL Failed to Conduct Additional Analyses; Analyses it Did Do are Flawed

116. Of only half of the 258 MW of incremental hosting capacity is used, the benefits-to-cost ratio falls to 0.65.

117. As a condition of approval of its Pilot program, the Commission required that PPL compare the costs and benefits of active management of DERs by PPL's Devices, to the benefits available through the use of inverter autonomous grid support functions. PPL St. No. 1, p. 13.

118. PPL's analysis of its Pilot does not do so adequately.

119. The stated purposes of the Plan included managing DER reactive power "to help resolve voltage violations at the point of interconnection" (PPL St. No. 3, p. 40) and "to meet overall distribution system voltage objectives" (PPL St. No. 4, p. 19); increasing hosting

capacity and deferring capital upgrades (PPL St. No. 3, p. 38); and accessing a remote on/off capability (PPL St. No. 3, p. 54).

120. To date, PPL has not yet managed DER reactive power "to help resolve voltage violations at the point of interconnection," PPL St. No. 3, p. 43.

121. To date, PPL's active management of DER reactive power has not yet avoided specific investments, PPL St. No. 3, p. 49.

122. To date, PPL has not used its active management capabilities to remotely access the inverters' on/off functionality. PPL St. No. 3, p. 55.

123. The JSPs calculate that PPL's active management has resulted in no change to the number of voltage violations 63 percent of the time; increased voltage violations 27 percent of the time; and reduced voltage violations 10 percent of the time. JSP St. No. 6, p. 16.

124. Mr. Wishart did not include a comparison of benefits to be obtained from autonomous inverter functions v. active management. PPL St. No. 10-RJ, p. 4.

125. Mr. Wishart also did not evaluate any alternate approaches, such as Flexible Interconnection. PPL St. No. 10-SR, p. 23.

126. Flexible interconnection offers reduced interconnection costs for DER owners who elect to limit the power that their systems can export to the grid, such as California Rule 21's Limited Generation Profile,[8] under which Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company define conditions of operations to allow DERs to perform within existing hosting capacity constraints and avoid triggering distribution grid upgrades. JSP St. No. 9, p. 11.

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[8] *See* Ordering Paragraph 2, p. 102, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M527/K981/527981713.PDF.

127. The UL 3141 standard, which certifies system-level Power Control System functionality to provide time-based import and export limitations, can serve as the basis of flexible interconnection options for customers. JSP St. No. 6-SR, p. 10.

128. PPL did not analyze any other mechanism, including lower-cost mechanisms, or approaches to employ in "controlling" the DER other than PPL's Device.

129. Enphase's customer-owned modem that communicates through the cloud. should be able to provide an equivalent level of reliability to PPL's DER Management Device, one of which is a cellular gateway.

130. The Enphase modem is listed for $410.50, and can easily be installed by customers themselves. JSP St. No. 6-SR, p. 10.

131. The weighted average cost of PPL's DER management device is $959. PPL St. 10-R, Table SWW 5.

132. The Enphase modem's lower per unit cost, reduced or avoided costs from labor and truck rolls to oversee installation, and op-ex treatment for customer rebates rather than capitalizing equipment cost and adding it to the ratebase, would provide greater net benefits for PPL customers. JSP St. No. 6-SR, p. 11.

133. PPL did not also analyze whether it could procure grid services using a third-party aggregator. JSP St. No. 6, p. 20.

134. Aggregation is a service in which an entity controls multiple DERs simultaneously in order to provide grid services, demand response, ancillary services, balancing services, voltage or frequency regulation, or other services as called upon. These aggregations can perform services in response to utility-level signals or in response to wholesale electricity market operations. JSP St. No. 6, p. 20.

135. The SolarEdge inverter can automatically communicate with its built-in modem, eliminating the need for a DER Device or an AMI network to talk to the Device, and for the truck rolls and equipment costs associated with these installations. JSP St. No. 7, p. 21; JSP St. No. 7-SR, pp. 22 – 23.

136. Lowering lower cap ex reduces costs for ratepayers. *Id.*

137. Another stated purpose of PPL's Program was to facilitate PPL's monitoring of real power, reactive power and voltage (PPL St. No. 3, pp. 13).

138. Also as a condition of approval of PPL's Pilot Program, the Commission also expressly required that PPL test and evaluate the costs and benefits of monitoring DERs through PPL-owned devices connected to customer-owned inverters, as compared to maintaining distribution system status visibility through other means (e.g., automated reading equipment, advanced distribution systems ("ADMS"), modeling). Recommended Decision, Docket No. P-2019-3010128, ¶ 54.

139. More than 67 percent of all projected program benefits, or $98.6 million of the $146.6 million, from monitoring, rather than active management. JSP St. No. 4-SR, *citing* PPL St. No. 10-R, p. 9, Table SWW-2.

140. PPL neither tested nor analyzed alternative methods it could use to obtain monitoring data, such as use of API.

141. APIs provide data and access over "the cloud, so can be provided via a network of remote serves that are accessible over the internet." JSP St. No. 4, p. 22.

142. The Government of Western Australia (which receives upwards of 80 percent of its total energy from solar) is using this solution. JSP St. No. 4-SR, p. 23; JSP Ex. JG-12SR.

143. Portions of PPL's analysis in the 2024 DER Management Report compared benefits of active management in reducing the duration and frequency of voltage violations only to a "Grandfathered Group" of DERs that were not subject to active management or smart inverter settings, so do not provide information regarding the benefits of active management compared to autonomous smart inverter settings in regard to voltage regulation.[9]

144. In the portions of PPL's analysis that compared feeders with actively managed DERs to those with only autonomous smart inverter settings, PPL limited its analysis to Control Group 1 feeders, which comprised DERs on 75 specific circuits, and did not compare actively managed DERs to Control Group 2, which comprised 1,000 DERs located across PPL's grid and which had autonomous smart inverter settings activated.[10]

145. PPL conducted no regression analysis to determine whether changes in voltage frequency and duration were due to the active management, the smart inverter settings, or numerous other factors that affect voltage, stating that the "the impact of active management on the duration and frequency of voltage violations is readily apparent."[11]

iii. PPL Has Failed to Analyze the Magnitude of Harms Its Program Has Done and Will Do to the JSPs, to Other Solar Customers and Companies, and to the Public Interest Generally

1. PPL Has Failed to Account for Lost Sales Resulting from its Program Restrictions

146. AHC provided evidence showing it denied sales to at least 52 customers because it could not provide the customers with the products that the customers requested as the products

[9] JSP St. No. 6, p. 13-14.
[10] JSP St. No. 6, p. 14.
[11] See, PPL Electric Exhibit CD-4, p. 15.

were not on PPLs Approved List. JSP St. No. 2-SR, p. 11; Ex. JSP-NZ-6SR (REDACTED).

147. Pennsylvania is AHC's second largest market and would be its largest, if AHC were still able to sell, install, and service Tesla products in PPL territory. JSP St. No. 2, pp. 2, 3

148. Sun Directed testified that it has denied service to larger-size single phase commercial projects because it could not use the inverters that in its professional judgment were the best value for its customers, as they were not on PPL's Approved List. JSP St. No. 3, p. 4.

149. As there are 3 main utilities in Central Pennsylvania, the area Sun Directed serves, PPL's program has limited 1/3rd of Sun Directed's business. JSP St. No. 3, p. 5.

150. AHC based its information on the location of the sites where sales were lost on, *inter alia*, copies of the customers' utility bills. JSP St. No. 2-SR, pp. 9 - 10.

151. Sun Directed based its calculation that PPL comprises 1/3rd of Sun Directed's, *inter alia*, on the larger number of high population cities in PPL. JSP St. No. 3-SR, p. 9.

152. AHC testified that "mixing and matching" approved and non-approved products was "not feasible," JSP St. No. 2-SR, p. 6, because the non-approved Tesla Powerwall battery with integrated inverter is unique, JSP St. No. 4; because "mixing and matching" means the customer has to chase down two manufacturers to pursue a warranty claim, *Id*. at p. 6; and because mixing and matching results in sub-optimal product performance, and higher prices, and assumes substitute components are available, which AHC has not found to be the case. *Id*.

153. Sun Directed testified that substitution was infeasible because PPL-approved products were higher-priced, based on the Company's cost comparison analyses run for real

clients, showing a price differential for a larger size single-phase residential project of **[REDACTED]**,[12] and for a smaller project, of **[REDACTED].**

154. Sun Directed compared the prices of a non-approved "string" inverter to the approved micro-inverter because the approved string inverters were not those with which Sun Directed field staff had experience installing, were not made in America, which would jeopardize customers' ability to qualify for grants, or were products with which he was unfamiliar so could not recommend them to customers. JSP St. No. 3-SR (HIGHLY CONFIDENTIAL), pp. 6 - 7.

155. The non-approved products AHC and Sun Directed wish to use are certified to meeting national standards. JSP St. No. 2-SR, p. 4; JSP St. No. 3-SR, p. 5.

156. AHC calculated that the 31 lost sales would have produced 512.13 kW and 114 batteries. JSP St. p. 2, p. 5/Ex. JSP-NZ-1.

157. The Tesla Powerwall that is unable to be sold in PPL is less costly and more efficient. JSP St. No. 2-SR, p. 7.

158. The Tesla Powerwall that is unable to be sold in PPL accounted for more than half of the U.S. national solar-plus-storage battery manufacturer shares by installation count from 2018 to 2023. JSP St. No. 4, p. 23.

159. Tesla provided evidence showing it was forced to redesign and downsize four solar systems, totaling a cumulative reduction of 37.6 kW-AC of those systems and a commensurate loss in sales,[13] due to PPL's March 2023 restriction[14] that limited Tesla

[12] Regarding the larger-size project, *see* JSP St. No. 3, p. 4; JSP St. No. 3-SR, p. 2. Regarding the smaller size, *see* JSP St. No. 3-SR, pp. 3, 7; Ex JSP-MS-1 (HIGHLY CONFIDENTIAL) (price list), and Ex. JSP-SD-1SR (cost comparison).
[13] See JSP Ex. JG-8SR - HIGHLY CONFIDENTIAL Ex. PPL to JSP-VI-6 Att. JG-1
[14] See Ex. JSP-JG-4 CONFIDENTIAL

installs containing SolarEdge or Delta inverters with Zigbee communications chips to single-inverter installs.

160. Tesla ceased doing new installations in PPL territory in the summer of 2023. JSP Statement No. 4, at p. 2.

161. In October 2023, Tesla closed its Tesla Energy warehouse in Norristown, Pennsylvania. *Id.*

2. PPL Has Failed to Account for Additional Losses to Pennsylvania Businesses and Customers

162. Trinity Solar testified it has not lost sales as a result of PPLs' program, but has lost profits, as it has absorbed the higher costs of doing business in PPL territory. Trinity calculates it lost approximately **[REDACTEDN]** based on the prices paid in 2023 on the 1,700 projects it installed in PPL territory with PPL-approved inverters, and the higher labor costs associated with installing the approved inverters, as well as additional man-hours, personnel, and truck rollouts uniquely associated with installing and servicing installations containing or potentially containing PPL's DER Management Device. JSP St. No. 5, pp. 3 – 4, 5; JSP St. No. 5-SR, pp. 3, 7.

163. Trinity showed that servicing customers' inverters is delayed by upwards of 14 days, due to PPL's being the only entity able to install or remove its device from a customer's inverter. JSP St. No. 5, p. 5.

164. In some cases, completion of a service job has taken up to 75 days, PPL St. No. 5-SR, p. 6; Ex. JSP-RP-4SR, causing significant customer dissatisfaction, JSP St. No. 5-SR, p. 6; Ex. JSP-RP-5SR.

165. The delays increased Trinity's costs by about an additional **[REDACTED]** per year, due to additional days of field techs' time, JSP St. No. 5, p. 5, and the costs associated with its hiring an additional staffer to coordinate service visits. JSP St. No. 5, p. 7; JSP St. No. 5-SR, pp. 5 - 6.

166. Trinity testified that this coordination between PPL, Trinity, and the customer is unique to PPL's territory because of PPL's program and is not required in other areas. JSP St. No. 5-SR, p. 7.

167. Green Way showed that its customers have experienced lengthy delays in receiving permission to operate ("PTO"), as a result of their having to await PPL's installation of its Device, sometimes up to 47 days following the date of the electrical inspection. JSP St. No. 10, pp. 3 – 4; Ex. JSP-WS-1, Slides 16-23.

168. Green Way testified that a 38-day delay in obtaining PTO cost one customer $116,000.00, because his ability to obtain financing was pegged to his showing that his system was successfully operating for 30 days. JSP St. No. 10, pp. 5-6.

169. Green Way testified that the delay Green Way and its customers are experiencing is unique to PPL territory, as no other utility has a requirement to install utility-owned equipment on inverters. JSP St. No. 10, p. 4.

170. In estimating revenues lost as a result of having to use PPL-approved equipment, Trinity also used the prices of equipment its staff knows how to install and that Trinity believes is the best quality, and American-made; and included the additional labor costs associated with installing the additional components comprising the PPL-approved equipment). JSP St. No. 5-SR, pp. 2 – 5.

171. The additional components (such as the SolarEdge power optimizer), are integral to using the SolarEdge inverters, not "optional," and Trinity's price estimates are solid.

172. Regarding the numbers of times service visits required coordination, Trinity testified it coordinates in all instances, because it does not know in which inverters PPL has installed its Device. JSP St. No. 5-SR, p. 5.

173. Green Way Solar's evidence on days lapsing between an electrician completing his or her inspection and PPL's issuance of PTO showed all required signatures. JSP St. No. 10-SR, p. 5.

3. PPL's Program Blocks or Limits Market Entry

174. Enphase expended resources seeking to obtain PPL approval of and support for its inverters, which were certified as meeting an IEEE 2030.5 interface, per California Rule 21 requirements, Ex. JSP-MM-3SR, because PPL initially sought to require all inverter products to be capable of communicating through DNP3 or SunSpec Modbus, due to PPL's having not yet completed an integration of IEEE 2030.5 into its AMI network. JSP St. No. 6, p. 5.

175. Upon PPL's agreeing to use Enphase's product, Enphase sent free equipment to PPL's lab, and provided remote support as PPL worked to integrate Enphase into its servers. *Id*.

176. Enphase estimates it took three months of lab work for PPL to successfully "get the client to communicate with their servers," followed by ongoing troubleshooting and debugging tasks to ensure that commands were working as intended, and the expenditure of significant resources by both (approximately 250 hours of PPL staff time, and 150 hours of Enphase staff time). *Id*., p. 6.

177. In addition to losing sales during this four month period, Enphase observed several installers and/or pending projects switch to competitor products. *Id*., p. 5.

178. Enphase testified it has not been required to dedicate this level of attention to operations in other similarly sized utilities' territory. JSP St. No. 6, p. 6.

179. When the Pilot commenced on January 1, 2021, SolarEdge inverters purchased by customers who were awaiting PTO did not yet meet the not-yet effective UL 1741 SB Standard. *See* JSP St. No. 7, p. 4.

180. To obtain PTO for its customers, SolarEdge customized a solution that involved showing PPL its inverters already contained the "read functions" that would be required by UL 1741 SB, JSP St. No. 7, p. 4, using a function SolarEdge calls Modbus mapping. PPL Ex. AD-22R (HIGHLY CONFIDENTIAL).

181. SolarEdge delivered Modbus register maps to PPL, and helped train the PPL team on how to use the maps. JSP St. No. 7, p. 4.

182. SolarEdge estimates its development of this custom solution required that an employee dedicate a full two weeks of work (worth approximately $6,460) over the period from January 1, 2021 to January 28, 2021, JSP St. No. 7, p. 4, pp. 4 – 5, diverting his time from securing new business. JSP St. No. 7, p. 5.

183. SolarEdge testified it lost or experienced delays in sales during the 28-day period it awaited approval of its inverters' inclusion on PPL's Approved List. JSP St. No. 7, p. 3.

4. PPL Fails to Account for the Interference with Customers' Communications and Power Generation Caused by its Device

184. Tesla's solar inverter used in Tesla solar panels and solar roofs, and the inverter integrated into its Powerwall batteries are certified to IEEE 1547-2018 and UL 1741 SB standards

but are not on PPL's Approved Smart Inverter List, as Tesla has not submitted them for testing.

185. As discussed above in Section III.b.i., PPL's restrictions have limited 41 inverters to multi-use configurations due to PPL's requirement that inverters be able to be networked.

186. In at least 27 Tesla multi-inverter solar systems installs involving PPL-approved Delta or SolarEdge inverters, all involving ZigBee communications modules, and all containing PPL's Device, communications and data from customers' systems were fully or partially knocked offline. JSP St. No. 4-SR, p. 4-5; JSP Ex. JG-2SR HIGHLY CONFIDENTIAL.

187. Cumulatively, the 27 systems had one or more inverters not sending communications for 6,933 days, or an average of 256 days/system. JSP Ex. JG-2SR HIGHLY CONFIDENTIAL.

188. The disruptions commenced when PPL installed its Device and changed the inverter ID numbering in multi-inverter solar installations, JSP St. No. 4, p. 7, resulting in neither Tesla nor its customers being able to see communications data from any inverter other than the inverter numbered "1," JSP St. No. 8, blocking them from seeing how the entire solar system was producing and functioning.

189. Beginning in March 2023, PPL informed Tesla it would not grant PTO to any multi-inverter Tesla solar system using ZigBee in a SolarEdge or Delta inverter, Ex. JSP-JG-3; Ex. JSP-JG-4 (HC), until Tesla developed a software patch to BEGIN CONFIDENTIAL INFORMATIO "allow both PPL and Tesla to monitor our mutual customers DER systems." JSP St. No. 4-SR (HIGHLY CONFIDENTIAL), pp. 15-16.

190. Due to the restriction on multi-inverter installs, Tesla redesigned four solar systems, reducing the size of the systems from what Tesla's customers originally ordered, totaling a cumulative reduction of 37.6 kW-AC. JSP St. No. 4-SR, p. 15.

191. In the summer and fall of 2024, PPL determined it could allow for full communications for both Tesla and PPL systems using SolarEdge inverters (15 of the 27 Tesla-installed systems experiencing communications disruptions) by using a "register map for the Modbus register 700 series" that PPL obtained from SolarEdge in order to fix this issue. PPL St. No. 2-R, p. 37. By using the register map, PPL was able to set a unique Modbus ID number for each SolarEdge inverter, which in turn provided full system data communications for the customers, for PPL, and for Tesla.

192. However, the fix came only after 3 years of troubleshooting. JSP St. No. 4-SR, p. 10.

193. Similarly, Tesla and PPL recently found that they may employ a grid code used in New York to resolve the disruptions to systems using Delta inverters. *See* JSP St. No. 4-SR, pp. 7 – 10.

194. Pending PPL's discovery of this "fix," Tesla spent significant resources attempting to resolve harms caused by PPL's Pilot, and customers lost value. JSP St. No. 4, pp. 5, 9-12, 18.

195. Tesla has installed roughly 453,000 residential solar systems across the country with one or more Zigbee communications modules installed. In no other territory have Zigbee communications modules posed the communications problems Tesla experienced in PPL's territory. JSP St. No. 4, p. 9.

196. In no other territory has a utility limited installations of inverters with ZigBee modules to a single inverter. JSP St. No. 4, p. 9.

197. All the inverters Tesla installed under PPL's Pilot were on PPL's Approved Inverter List, and Tesla has produced evidence showing that the ZigBee communications modules Tesla used in the PPL-approved inverters were either already installed, or approved for use, by SolarEdge and Delta. JSP St. No. 4, p. 2; Ex. JSP-JG-2.

198. Enphase recorded 18 incidents between April 30, 2024 and July 22, 2024 in which PPL's DER Management Device disrupted communications and power production from customers' inverters. JSP St. No. 6, p. 7.

199. In 8 of the 18 instances, customer communications were disrupted because PPL was sending commands to the Enphase IQ Gateway (which manages local and cloud communications at the customer's premises) in the wrong units. JSP St. No. 6, p. 8.

200. Evidence PPL offered in support (PPL Ex. AD-19R) contains no indication that Enphase erroneously "directed" PPL as to the units to use. *See* JSP St. no. 6-SR, p. 2.

201. In these 8 instances, the disruption also halted power production from the customers' solar systems. JSP St. No. 6, p. 8; Ex. JSP-MM-3 (noted as "Issue 1"). REDACTED Ex. JSP-MM-3.

202. The 8 systems experienced at least 419 cumulative days of solar power production downtime, resulting in an estimated 12,570 kWh of lost energy, assuming each system produced an average of 30 kWh of energy per day. ///

203. In 10 of the 18 instances, communication traffic emanating from PPL's modem clashed with communication traffic over the customer's Wi-Fi related to local system operations, disrupting the customers' systems' communications. JSP St. No. 6, p. 8.

204. In 5 of these 10 instances, the disruption also halted power production from the customers' solar systems. JSP St. No. 6 p. 8; Ex. JSP-MM-3 (noted as "Issue 2"). PPL has since

changed all DER Management devices to a different LAN IP, which resolved the issue. PPL St. No. 2-R, p. 33.

205. As a result of these disruptions, Enphase's customers experienced at least 617 cumulative days of solar power production downtime, and at least 609 cumulative days of communications downtime. JSP St. No. 6, p. 8; Ex. JSP-MM-3.

206. Cumulatively, because of the disruptions caused by PPL's installation of its Device, the Commonwealth lost at least 18,410 kWh of solar power generation from these customers' inverters. JSP St. No. 6, p. 9.

207. Cumulatively, because of the disruptions caused by PPL's installation of its Device, Enphase customers lost at least $1,851 worth of net energy metering credits, as well as lost SREC values. JSP St. No. 6, p. 9.

208. Cumulatively, Enphase expended approximately $2,400 worth of labor to develop software fixes to resolve the two issues at the 18 sites. JSP St. No. 6, p. 9.

209. Enphase's costs do not include costs incurred by installers, who had to travel to each of the 18 sites at least once to perform troubleshooting and system reset activities on the physical systems. *Id*.

210. SolarEdge estimates it has spent 210 hours over the past two years supporting PPL's implementation of its program determining how to configure multi-inverter systems. JSP St. No. 7, p. 6; Ex. JSP-JB-2, Slide 14.

211. Historically, PPL's Device required a Modbus RTU port, while SolarEdge inverters have only a Modbus TCP (or ethernet) port available. JSP St. No. 7, p. 5.

212. At some point during the Program, PPL replaced the type of Device it was using with one able to be used with SolarEdge's Modbus TCP port. PPL St. No. 2-RJ, p. 40.

213. SolarEdge has not been required to meet utility-specific testing requirements that go beyond the requirements for IEEE and UL certification, or to provide ongoing technical support, in any other jurisdiction. JSP St. No. 7, p. 6.

214. While resolved, Sun Directed also provided evidence of instances in which customers were inconvenienced, and deprived of the value of their solar equipment, and Sun Directed lost money servicing their systems, which experienced interference as a result of PPL's DER Device installation. JSP St. p. 3, pp. 5 – 6.

5. PPL's Program is Blocking or Impeding Competition from Third-Party Grid Service Providers

215. Tesla testified that PPL's ability to assert primary control of a customer's inverter will be a significant blocker for third-party aggregators of battery energy storage in PPL's territory, and will block the provision of wholesale market grid services from aggregated DERs by creating unique and excessive risk and complexities for aggregators that ultimately will dissuade them from aggregating Pennsylvania-based DERs. *See*, JSP St. No. 8, at pp. 6-12.

216. Tesla testified that accommodating the utility control required by PPL's Pilot and Plan alongside a VPP program would require third-party aggregators, such as Tesla, to create novel technical solutions that would be unique to the PPL territory and would need to be capable of managing multiple points of communication and control. *See*, JSP St. No. 8-SR, at p. 3.

217. Tesla testified that the need to create such a novel technical solution would be costly and would act a significant barrier for aggregators to enter PPL's territory, particularly for aggregators looking to participate in PJM. JSP St. No. 8, at pp. 9-10.

218. Tesla also testified that the complexities of managing multiple points of communications and control created by PPL's Pilot and Plan, and of incorporating PPL management into VPP forecasting and dispatch strategies, would itself create an entirely new risk and complexity that is difficult for aggregators to assess and quantify, causing a significant deterrent to market entry. JSP St. No. 8-SR, at pp. 3-5.

219. Enphase testified that PPL's ability to update reactive power setpoints has the effect of reducing the active power potential of resources such as solar and batteries, which can otherwise be controlled by manufacturers' cloud Application Programming Interfaces ("APIs") for participation in grid services programs. JSP St. No. 6, p. 21.

220. Enphase also testified that PPL's hegemony over DER control presents a high degree of uncertainty for prospective third-party aggregators, interfering with their ability to be able to confidently deliver grid services, particularly wholesale electricity market reliability services. JSP St. No. 6, p. 20.

221. SolarEdge also testified that PPL's program blocks its ability to confidently develop an aggregation program. JSP St. No. 7-SR, p. 20.

222. The JSPs agree there are uncertainties that are common to all distribution systems such as weather, circuit outages, and equipment failures, but testified that their main concern is that the new uncertainties introduced by PPL's program are unique to PPL's territory, and pose unique risks and complexities that would be costly to design around. JSP St. No. 8-SR, p. 3.

223. PPL's DER Lab testing "to ensure that [the inverters] are compatible with PPL Electric's DER Management Devices involves PPL's " ... DER Lab verif[ying that, *inter alia*] the inverter has … an open and available [communications] port." PPL St. No. 2-R, p. 19.

224. Mr. Lydic also testified that because PPL's Tariff requires that "the Company shall be permitted to actively monitor and manage the grid support functions of DER inverters using the DER Management Device and the Company's Distributed Energy Resources Management System (DERMS)." JSP St. No. 9-SR, at p. 14.

225. SolarEdge equipment "cannot communicate with multiple entities at the same time." JSP St. No. 7-SR, p. 22.

226. SolarEdge testified that its equipment "adher[es] to the proper communications protocols required by the applicable standards," but IEEE 1547-2018 "is silent about communicating with multiple entities at the same time for the purposes of [providing] grid support." JSP St. No. 7-SR, p. 23.

227. The JSPs testified that SCADA systems, are expensive ($100,000.00), and more typically used in large, industrial settings, not the residential systems at issue in this litigation. JSP St. No. 7-SR, p. 22.

6. PPL fails to account for its device installations violating the National Electric Code, Voiding Customers Warranties.

a. PPL's method of connecting its device to SolarEdge inverters violates the NEC.

232. PPL has installed its Device in nearly 8,000 SolarEdge inverters. PPL St. No. 2-RJ, p. 34.

233. In each instance, PPL has connected its Device in the portion of the SolarEdge inverter known as the "communications box" to establish communications between the inverter and the SolarEdge device, and has connected wires to another portion of the inverter to power the Device. JSP St. No. 14-SR, p. 3.

234. The purpose of the National Electrical Code "is the practical safeguarding of persons and property from hazards arising from the use of electricity." NEC 90.1(A).

235. Section 690.4 (General Requirements) of the National Electrical Code, covering Solar Photovoltaic (PV) Systems states that the article applies to inverters for such systems.

236. NEC Section 90.2(A) states that the NEC "covers the installation and removal of electrical ... equipment ... for public and private premises, including buildings."

237. 34 Pa. Code § 195(b) provides that the NEC applies for the installation of wiring.

238. The Commission's standardized form for interconnecting applicants requires that per NEC requirements, an interconnecting inverter-based system must be inspected by an electrical inspector. Feb. 26, 2009, Pa. PUC, Docket No. M-00041865, *Implementation of the Alternative Energy Portfolio Standards Act of 2004: Standard Interconnection Application Forms*.

239. NEC 90.2(B) ("Not Covered") states: "This Code does not cover … (5) Installations under the exclusive control of an electric utility ... "

240. However, the utility's installation of its utility-owned Device on the customers' side of the meter is subject to the NEC. *See* NEC 90.2(a)(4), which provides: "Installations used by the electric utility, such as office buildings, warehouses, garages, machine shops, and recreational buildings.

241. NEC Section 110.3(B) mandates that "Equipment that is listed, labeled, or both, or identified for a use [] be installed and used in accordance with any instructions included in the listing, labeling, or identification."

242. The SolarEdge inverter for residential systems and instructions for installing it and related equipment are UL-certified (Ex. JSP-JB-6SR) by a NRTL, Ex. JSP-JB-6SR, p. 2

of 14, and are contained in SolarEdge's "Installation Guide: SolarEdge Home Hub Inverter Single Phase for North America, Version 1.7." (Ex. JSP-SD-4SR).[15]

243. The Guide provides instructions for installing communications options, including communications with SolarEdge's monitoring platform, for the SolarEdge Energy Bank, a battery, a Backup Interface, a Smart EV Charger, a meter, and an additional Energy Hub inverter. Ex. JSP-SD-4SR, pp. 35, 46, 48, 49, 53.

244. As admitted by PPL, the Guide contains no instructions on installing a third-party device such as PPL's DER Management Device to the inverter to power the third party's Device. Hrg. Tr., p. 382.

245. As SolarEdge's instructions do not authorize PPL's method of installation, PPL's method is unauthorized.

246. The terminals to which PPL connects are screw terminals designed to hold in place SolarEdge factory wires that SolarEdge connects to the inverter (depicted with the red arrow on Ex. JSP-JB-3SR). They are extremely delicate, and are factory-torqued in a controlled environment in conformance with SolarEdge's factory torque specs. JSP St. No. 7-SR, p. 4.

247. Terminals that are designed and able to provide power, or "field terminals," are "push-in terminals," located in a wholly separate compartment in the inverter (marked with the green arrow on Ex. JSP-JB-3SR) that permit installation using a screwdriver. *Id.*, p. 5.

248. PPL is connecting its wires in a part of the inverter that is assembled only in a factory setting, and is a location SolarEdge intends no human touch. JSP St. No. 7, p. 10.

[15] Ex. JSP-SD-4SR was inadvertently designated as HIGHLY CONFIDENTIAL. The document is publicly available, so is reproduced and attached hereto as such.

249. As PPL's expert admitted, PPL's torquing specs pertain to the torque to be applied to the Hex screws on the inverters' external covers, not the Phillips "screw terminals" in the inside of the inverter. PPL Ex. AD-19RJ; Hrg. Tr., pp. 301 – 302, 303.

250. Another SolarEdge guidance, SolarEdge's Guide for Installing SolarEdge's "Commercial Gateway with Cellular Support" provides guidance on installing <u>SolarEdge's Gateway</u> in a <u>Commercial</u> setting, as it , not to a third-party "gateway" installed in a residential setting.

251. The SolarEdge Gateway "transfer[s] <u>monitoring data</u> from SolarEdge and non-SolarEdge devices "to the SolarEdge monitoring server ...," Hearing Ex. JSP-2D, p. 8. It does not transfer <u>power</u> from a SolarEdge inverter to a third-party management Device. Hearing Ex. JSP-2A, p. 7.

252. All iterations of the Manual provide instructions on powering the SolarEdge Gateway, but instruct that to "connect [SolarEdge's gateway] to power, use the supplied power supply," which is the "interchangeable AC plug," or wall plug, that SolarEdge ships to the customer in the same package in which it ships its Commercial Gateway.[16]

253. The instruction cited by Ms. Dombrowski-Diamond in the Hearing[17] states:

> For connecting to power, use the supplied power supply . . . If you use a non-SolarEdge power supply, check that it has 12Vdc/1A output ratings, and that it is certified to UL/CSA/IEC60950-1 2ed standards. Limited Power Source output, NEC class 2."

254. The "supplied power supply" is the "interchangeable AC plug." *See* JSP St. No. 7-SR, p. 6. The "non-SolarEdge power supply" is a power supply in lieu of the

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[16] *See* V. 1.0 (Hearing Ex. JSP-2A), p. 18; V. 1.1 (Hearing Ex. JSP-2B), pp. 19, 18, V. 1.2 (Hearing Ex. JSP-2C), pp. 19, 18; and V. 1.3 (Hearing Ex. JSP-2D), pp. 19, 18. *See also* JSP St. No. 7, SR, p. 6.
[17] Hearing Ex. JSP-2B, p. 20 (Hrg. Tr., Day 2, p. 356, lines 10 – 14).

"interchangeable AC plug" provided by SolarEdge, Hearing Ex. JB-2D, p. 20, not the inverter. JSP St. No. 7-SR, p. 7.[18]

255. In no exchange cited by PPL[19] did SolarEdge orally, or in writing, "pre-authorize," approve, provide "prior written consent," or tell PPL that SolarEdge "had no issues" with PPL's manner of connecting its Device to the inverter to power the Device.

256. PPL's Device's product listing does not authorize PPL's powering in the manner PPL is doing. PPL Electric Exhibit AD-4

257. PPL developed instructions for installing its Device in the SolarEdge inverter to power it (PPL Electric Ex. AD-6, at Step 9, pp. 3 – 4, 9 – 10).

258. PPL's Lab is not a Nationally Recognized Test Lab. Hrg. Tr., p. 363.

259. PPL did not produce any information generated by its Safety Team pertaining to PPL's use of connectors underneath the SolarEdge inverter screws. Hrg. Tr., p. 36.

b. PPL's Violations of the NEC Has Also Voided Customers' Warranties

260. SolarEdge's warranty requires that SolarEdge replace a customer's SolarEdge products, including inverters, if they malfunction or fail under terms and conditions set forth in the warranty. JSP St. No. 7, p. 9.

261. The Warranty will not apply if the Product or any part thereof is, *inter alia*:

    1. "Damaged as a result of misuse, abuse, negligence or failure to maintain the Product;"
    2. "Damaged as a result of modifications, alterations or attachments thereto which were not pre-authorized in writing by SolarEdge;"

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[18] The instruction cited by Ms. Diamond-Dombrowski further instructs that the "power supply cable connector" be connected "to the connector labeled **DC** [power supply input] on the Commercial Gateway (see *Figure 3*)," Hearing Ex. JB-2D, p. 20, It does not instruct that the SolarEdge supplied cable connector be connected to the inverter's AC screw terminals, where PPL connects its wires to the inverter. It provides that the power supply should be connected to the **AC mains**. But "AC mains" refers to the wires that power the house branch circuits. JSP St. No. 7-SR, p. 7.

[19] *See* Exhibit JSP-AD-5SR, JSP-AD-7SR-A, JSP-AD-7SR-B, PPL Exhibit AD-4R, JSP Exhibit AD-9SR, JSP-AD-11SR, JSP-DF-1SR (PPL Exhibit AD-35R), JSP-DF-3SR, or PPL Exhibit AD-1RJ.

3. “Opened, modified or disassembled in any way without SolarEdge’s prior written consent;” or

4. “Used in combination with equipment, terms or materials not permitted by the Documentation or in violation of local codes and standards ....“

Ex. JSP-JB-2, Slide 2.

262. Although PPL’s connections of its wires actions voided the customers’ warranties, SolarEdge voluntarily replaced damaged customers’ inverters. Ex. JSP-JB-2 (REDACTED), Slides 5 – 13. JSP St. No. 7, p. 11.

263. SolarEdge’s inverter replacements to date have cost about $12,530, which figure includes materials and labor but excludes the costs of customer support and shipping. JSP St. No. 7, p. 15; and Ex. JSP-JB-2 (REDACTED AND PUBLIC), Slide 14.

c. PPL’s Installations Have Caused at Least 9 Instances of Thermal Damage

264. On August 22, 2024, SolarEdge was called by an installer who observed smoke coming from a customer’s inverter. JSP St. No. 12-R, p. 8.

265. The smoke is visible on Ex. JSP-JB-2, Slide 6. JSP St. No. 12-R, p. 8.

266. As a smoking inverter is quite unusual, and as the customer had lost generation, the field team escalated the case to SolarEdge personnel, including SolarEdge’s Failure Analysis Engineer, Jacob Geller. JSP St. No. 12-R, p. 8.

267. Based upon his review of the photographs, Mr. Geller immediately saw PPL’s connection to the inverter and concluded that the unauthorized modification caused the thermal damage. JSP St. No. 12-R, p. 8.

268. Because the photographs showed PPL’s wires, SolarEdge’s Code Compliance Officer commenced an inquiry into whether other like instances had occurred in PPL territory, yielding the package referred to as the September 19, 2024 PPL Case Review, showing

evidence of 8 instances of thermal damage to inverters that have or had PPL's Device installed. *Id*. at pp. 8-9.

269. Based on photographs and field service tech reports (JSP St. No. 13-SR, p. 4), Mr. Geller testified:

> In my opinion, in all 8 cases we had clear evidence of thermal damage to the inverters, all of which have or had PPL's device installed. The ability to identify causation varies, but it is clear that in each case, the thermal damage arose from PPL's installations reducing spacing; over-torquing, cross-threading, or not sufficiently tightening screws; leaving behind contamination; or leaving bare wire exposed and in contact or in proximity with the circuit board, all of which could cause thermal arcing. Or, the thermal damage arose as a result if the installer causing mechanical damage to components during installation, which can also cause thermal damage.

JSP St. No. 13-SR, p. 4.

270. Mr. Geller characterizes his analysis as a "root cause" analysis.

271. Mr. Geller subsequently supervised an experiment in the SolarEdge laboratory that showed that a loose screw that was hand-tightened would cause the type of thermal damage seen in the PPL case review. JSP St. No. 13-SR, p. 7; Ex. JSP-JIG-13SR.

272. During discovery, PPL informed the JSPs of a 9th instance of thermal damage. *See* JSP St. No. 13-SR, Section III.

273. The correspondence cited by PPL discusses a hardware error but does not contain an any statement by SolarEdge that the error caused the thermal damage. PPL Exhibit AD-1RJ.

274. The correspondence cited by PPL shows that the thermal event PPL observed occurred in February, 2023.

275. Documents produced by PPL show that the hardware error referred to in the correspondence occurred in June, 2022. JSP St. No. 12-SR, p. 6.

PROPOSED CONCLUSIONS OF LAW

1. The Commission has jurisdiction over the subject matter and the parties to this proceeding. 66 Pa.C.S. §§ 501, 1302, 1303.
2. PPL Electric is a "public utility," an "electric distribution company" and a default service provider" as defined in Sections 102 and 2803 of the Public Utility Code, 66 Pa.C.S. §§ 102, 2803.
3. Section 5.41 of the Commission's regulations states, in part, that "[p]etitions for relief under the act or other statute that the Commission administers, must be in writing, state clearly and concisely the interest of the petitioner in the subject matter, the facts and law relied upon, and the relief sought." 52 Pa.Code § 5.41(a).
4. "Unless the Commission otherwise orders, a public utility . . . may not change an existing and duly established tariff, except after notice of 60 days to the public." 52 Pa. Code § 53.31.
5. Electric distribution companies (EDCs) are required to "file a tariff with the Commission that provides for net metering consistent with" Chapter 75 of the Commission's regulations. 52 Pa.Code 75.13(c).
6. An EDC and default service provider (DSP) "may not require additional equipment or insurance or impose any other requirement" on a net metering customer-generator "unless the additional equipment, insurance or other requirement is specifically authorized under this chapter or by order of the Commission." 52 Pa.Code § 741.13(k).
7. 66 Pa.C.S. § 1301 requires that every rate made or demanded by a public utility shall be just, reasonable, non-discriminatory, and in conformity with the regulations or orders of the Commission. *Metro. Edison Co. v. Pa.PUC*, 22 A.3d 353, 372 (Pa. Commw. Ct.

2011), *cert. denied*, 568 U.S. 959 (U.S. 2012) (“*Metro. Edison*”), *and Lloyd v. Pa.PUC*, 904 A.2d 1010, 1021 (Pa. Commw. Ct. 2006).

8. 66 Pa.C.S. § 102 defines a “rate” as including any rules, regulations, practices, classifications or contracts affecting utility charges. *Id*. at 359.

9. 66 Pa.C.S. § 315 places the burden of proof on a public utility to establish the justness and reasonableness of its rates and this burden is an affirmative one. *Berner v. Pennsylvania*

10. “Substantial evidence” is such relevant evidence that a reasonable mind might accept as adequate to support a conclusion. More is required than a mere trace of evidence or a suspicion of the existence of a fact sought to be established. *Norfolk & Western Ry. Co. v. Pa. Pub. Util. Comm’n*, 413 A.2d 1037 (Pa. 1980).

11. 52 Pa. Code § 75.22 requires interconnecting DERs to be certified to meet “(i) IEEE Standard 1547, ‘standard for Interconnecting Distributed Resources with Electric Power Systems,’ as amended and supplemented,” and “(ii) UL Standard 1741, ‘Inverters, Converters and Controllers for use in Independent Power Systems’ (January, 2011), as amended and supplemented.”

12. 52 Pa. Code § 75.22 defines a Certified DER as having as having a “designation that the interconnection equipment to be used by a customer-generator complies with the following standards as applicable: (i) IEEE Standard 1547, standard for Interconnecting Distributed Resources with Electric Power Systems,’ as amended and supplemented,” and “(ii) UL Standard 1741, ‘Inverters, Converters and Controllers for use in Independent Power Systems’ (January, 2011), as amended and supplemented.”

13. 52 Pa. Code § 75.22 defines a Nationally Recognized Testing Lab ("NRTL") as one recognized by the U.S. Department of Labor's Occupational Safety and Health Administration ("OSHA") as meeting the requirements in 20 C.F.R. 1910.7 to perform testing and certification of procedures of products using consensus-based test standards.

14. PPL has not provided evidence in this proceeding to support a finding that it is reasonable for it to deny permission to interconnect for a Distributed Energy Resource ("DER") using an inverter that has been certified as meeting the IEEE 1547-2018 standard but that does not meet the interoperability requirements of its First or Second DER Management Plans which exceed the standard.

15. 34 Pa. Code § 195(b) requires that the requirements of the National Electrical (Fire) Code be followed for the installation of wiring.

16. When a public utility takes action on the on the customer side of the meter, it is subject to the National Electric Code. NEC 90.2(A).

17. PPL's installation of its DER Management Device in customers' inverters is subject to the National Electrical Code.

18. NEC Section 110.3(B) requires that "Equipment that is listed, labeled, or both, or identified for a use [be] installed and used in accordance with any instructions included in the listing, labeling or identification."

19. PPL's connection of its DER Management Device to power it from the SolarEdge inverter was not authorized by SolarEdge instructions.

20. PPL's connections of its DER Management Device to power it from the SolarEdge inverter violates NEC Section 110.3(B).

21. PPL has not provided evidence in this proceeding to support a finding that its Second DER Management Plan is reasonable, just, in the public interest, and non-discriminatory.

PROPOSED ORDERING PARAGRAPHS

1) PPL is ordered to cease requiring that inverters be tested for compatibility with its DER Management Device.

2) PPL's Petition for Approval of its Second DER Management Plan is denied, although PPL may continue to require smart inverter settings that provide voltage regulation via autonomous functions.

3) PPL's First DER Management Plan and associated tariff shall terminate on the effective date of this Order, such that PPL shall not deny use of inverters in its territory that do not comply therewith, nor mandate installation of its management device.

4) PPL shall replace all SolarEdge inverters in which it has installed its Device, or establish a $2,000,000.00 fund to pay for replacements of SolarEdge inverters in which it has installed its Device there has been thermal damage.

Board-Tech Elec. Co. v. Eaton Elec. Holdings LCC

Decided Oct 31, 2017

17-cv-5028 (KBF)

10-31-2017

BOARD-TECH ELECTRONIC CO., LTD., Plaintiff, v. EATON ELECTRIC HOLDINGS LCC, COOPER LIGHTING LCC, and DOES 1 through 10, Defendants.

KATHERINE B. FORREST, District Judge

OPINION & ORDER

:

In this case, Board-Tech Electronic Co., Ltd. ("Board-Tech"), a manufacturer and seller of light switches, asserts that its competitor, Eaton Corporation and Cooper Wiring Devices, Inc. ("Eaton"),[1] has engaged in false and misleading advertising. The nub of plaintiff's claim is that while defendants were authorized to apply the "UL" certification mark to certain products, those products did not in fact comply with the requisite safety standards. Eaton has moved to dismiss on two principle bases: (1) that by failing to specify which products are at issue (and instead only naming a range of products within three product categories), plaintiff has failed to comply with its basic Rule 8 pleading obligations, and (2) that in all events, plaintiff has failed to allege actionable falsity. *2

2

1 The complaint initially named Eaton Electric Holdings LLC and Cooper Lighting LLC as defendants. On consent, Eaton Corporation and Cooper Wiring Devices have been substituted as defendants.

For the reasons set forth below, the Court agrees with the defendant and GRANTS the motion to dismiss.

I. FACTS ALLEGED IN THE COMPLAINT

The facts set forth below are taken from the Second Amended Complaint.[2] While the Court accepts as true all well-pled factual allegations, it does not do the same with regard to legal conclusions; to the extent such conclusions are cited below, the Court's purpose is solely to fully set forth plaintiff's claims.

2 Defendants have attached a number of exhibits to the Declaration of Serrin Turner, dated September 22, 2017. (ECF No. 40.) The Court has only referred to Exhibits 3 and 4, the certification mark registrations. A court may properly take judicial notice of such registrations in connection with a motion to dismiss. See TCA Television Corp. v. McCollum, 839 F.3d 168, 173 (2d Cir. 2016) (taking judicial notice of copyright registrations at motion to dismiss stage).

Plaintiff Board-Tech, a Taiwanese Corporation, and Eaton, an Ohio Corporation, are competitors in the manufacture and sale of light switches.[3] Both have sought and obtained authorization from Underwriters Laboratories to apply its "UL" certification mark on products.

3 Defendant Cooper Wiring Devices, Inc. is a New York corporation acquired by Eaton Corporation in 2012.

To protect against certain dangers, including electrical fires and the risk of human injury, the U.S. government, retailers, businesses and consumers demand that the electrical products being used comply with industry safety requirements. (Second Amended Complaint ("SAC"), ECF No. 46, ¶ 18.) In the case of light switches manufactured and sold by plaintiff and defendants, the prevailing standard is UL 20, applicable to "General Use Snap Switches." (Id.) The National Electric Code ("NEC") requires light
3 switches in new buildings to be UL 20 *3 compliant; the NEC has been adopted at the state or local level in all 50 states. (Id. ¶ 20.) Even where use of a UL 20 switch is voluntary under the law, consumers rely on labeling that a product complies with safety standards at the time of purchase. (Id. ¶ 21.) Many retailers, such as Wal-Mart, additionally require compliance for products they sell. (Id.) "In practice, no manufacturer can expect to successfully operate in the U.S. light switch market without representing that its switches comply with UL 20." (Id. ¶ 22.) "[T]he form of manufacturer representation that governments and consumers routinely require is a certification by a third party testing organization." (Id.)

Entities that are designated as Nationally Recognized Testing Laboratories ("NRTLs"), are tasked with rigidly testing products according to standards developed by the Occupational Safety and Health Administration ("OSHA"). (Id. ¶ 23.) "Consumers and retailers have also come to rely on an NRTL approval, certification or 'listing' as a mark of safety." (Id.) Underwriters Laboratories serves as an NRTL. (Id. ¶ 24.)

Underwriters Laboratories owns the "UL" certification mark. (Turner Decl. Exs. 3, 4.) The 1964 UL mark registration states, "The certification mark is used by persons authorized by applicant to indicate that representative samplings of the products conform to the safety requirements used by the applicant." (Id., Ex. 3, p. 2.) The 2000 registration similarly provides, "The certification mark as used by persons authorized by applicant certifies that representative samplings of the goods conform to the requirements of the
4 applicant." (Id., Ex. 4, p. 2.) *4

In order to be authorized to apply the UL mark, a manufacturer must provide six sets of representative samples of switches they want certified to an NRTL, such as Underwriters Laboratories, for testing. (Id. ¶ 29.) The light switches must then pass a series of tests detailed in the booklet UL Standard for Safety for General-Use Snap Switches, UL 20, May 10, 2010, revised February 17, 2012. (Id. ¶ 27.) "Of course, an NRTL cannot test every product a manufacturer offers for sale prior to sale, and cannot be certain the samples provided by the manufacturer are of the same quality, or share the same properties as those the manufacturer sells to consumers." (Id. ¶ 29.) "Accordingly, NRTLs do not guarantee the products actually sold by a manufacturer comply with the applicable safety requirements; they only certify that a purportedly representative sample did." (Id.) Thus, according to plaintiff, "If a product carries [the UL Listing Mark], it means UL found that **a representative sample** of that product met UL safety requirements **and the manufacturer is representing that the product meets those requirements**." (Id.) (Citing a portion of the UL website) (emphasis in original).

Plaintiff further asserts that consumers rely on the certification mark or listing, and base their purchases on the belief that every product containing a mark or that is listed actually complies with the applicable written safety standards. (Id. ¶ 30.) After testing a product sample that meets requirements, "Underwriters Laboratories authorizes the use of its certification marks, on their products, packaging, and in their marketing and advertising, but according to the company, it is the responsibility of the manufacturer to ensure that all of the products it
5 sells *5 bearing the UL mark actually comply with the standards tested for, not just the samples that were tested." (Id. ¶ 31.)

"All of Defendants' light switches at issue in this case have been 'listed' or 'classified' by Underwriters Laboratories." (Id. ¶ 26.) Furthermore, "each of Defendants' light switches manufactured, marketed, advertised, and sold bearing the UL mark have in fact been granted permission for such use and 'listed' by Underwriters Laboratories as complying with UL 20." (Id. ¶ 32.)

Plaintiff asserts that in 2015-2017, it tested samples of switches actually sold by defendants, and that bear the UL mark. (Id.) The switches tested did not comply with the UL 20 standards. (Id.) Plaintiff alleges that it tested eight sets of six light switches (48 in total) from defendants' 7500, 7600, and 7700 series of products, for compliance with the UL 20 standards, and that all failed (Id. ¶¶ 37-39.) Based upon this testing, plaintiff asserts that "**none** of the General-Use snap switches identified in Exhibit A that Defendants advertise, market, and sell to consumers as UL Certified and compliant with UL 20 standards actually complies with those standards." (Id. ¶ 48.)

Plaintiff alleges that because defendants' light switches do not meet the UL 20 testing requirements, defendants' advertising that their light switches are UL 20 compliant is actually false and misleading. (Id.)

II. THE CLAIMS

Plaintiff has asserted claims for false advertising under the Lanham Act, 15 U.S.C. § 1125(a) (First Cause of Action), unjust enrichment (Eighth
6 Cause of *6 Action), and various state law claims arising under the laws of New York (Second and Third Causes of Action), California (Fourth and Fifth Causes of Action), Illinois (Sixth Cause of Action), and Texas (Seventh Cause of Action). As discussed below, all of the claims require some showing of falsity or other wrongful or inequitable conduct.

III. LEGAL PRINCIPLES

A. Motion to Dismiss

On a motion to dismiss, this Court accepts as true all well-pleaded factual allegations. See Ashcroft v. Iqbal, 556 U.S. 662, 678 (2009). This means that the Court must accept plaintiff's factual allegations in its complaint as true and draw all reasonable inferences in plaintiff's favor. See Famous Horse Inc. v. 5th Ave. Photo Inc., 624 F.3d 106, 108 (2d Cir. 2010). To withstand dismissal, "a complaint must contain sufficient factual matter, accepted as true, to 'state a claim to relief that is plausible on its face.'" Iqbal, 556 U.S. at 678 (quoting Bell Atlantic Corp. v. Twombly, 550 U.S. 544, 570 (2007)).

"A claim has facial plausibility when the plaintiff pleads factual content that allows the court to draw the reasonable inference that the defendant is liable for the misconduct alleged." Iqbal, 556 U.S. at 678. In applying this standard, the Court accepts as true all well-pled factual allegations, but does not credit "mere conclusory statements" or "[t]hreadbare recitals of the elements of a cause of action." Id. The Court will give "no effect to legal conclusions couched as factual allegations." Port Dock & Stone Corp. v. Oldcastle Ne., Inc., 507
7 F.3d 117, 121 (2d Cir. 2007) (citing *7 Twombly, 550 U.S. at 555). If the Court can infer no more than the mere possibility of misconduct from the factual averments—in other words, if the well-pled allegations of the complaint have not "nudged [plaintiff's] claims across the line from conceivable to plausible"—dismissal is appropriate. Twombly, 550 U.S. at 570.

B. Certification Marks Generally

Section 1054 of the Trademark Act provides for the registration of certification marks. 15 U.S.C. § 1054. The statute provides that "when registered they shall be entitled to protection provided herein in the case of trademarks, except in the case of certification marks when used so as to represent falsely that the owner or a user thereof makes or sells goods or performs the services on or in connection with which such mark is used." Id. A certificate of registration for such a mark sets forth the rights and limitations of use with goods and services. 15 U.S.C. § 1057. Any person who believes that he has been damaged by dilution, likelihood of dilution, dilution by tarnishment, may commence an action to cancel the registration. 15 U.S.C. § 1064. With regard to a certification mark, such an action may be commenced at any time on the ground that the registrant:

> (A) does not control, or is not able legitimately to exercise control over, the use of such mark, or (B) engages in the production or marketing of any goods or services to which the certification mark is applied, or (C) permits the use of the certification mark for purposes other than to certify, or (D) discriminately refuses to certify . . .

15 U.S.C. § 1064(5). Certification marks are "designed to facilitate consumer expectations of a standardized product, much like trademarks are designed to ensure that a consumer is not confused
8 by the marks on a product." Idaho Potato *8 Commission v. M & M Produce Farm & Sales, 335 F.3d 130, 138 (2d Cir. 2003). The certification mark regime "protects a further public interest in free and open competition among producers and distributors of the certified product." Id.

C. False Marketing and Advertising

Plaintiff's First Cause of Action is for false and deceptive advertising and marketing under the Lanham Act. Section 1125 of the Lanham Act provides:

> Any person who, on or in connection with any goods or services . . . uses in commerce any . . . false or misleading description of fact, or false or misleading representation of fact, which . . . in commercial advertising or promotion, misrepresents the nature, characteristic, qualities, or geographic origin of his or her or another person's goods, services, or commercial activities, shall be liable in a civil action by any person who believes that he or she is or is likely to be damaged by such act.

15 U.S.C. § 1125(a)(1).

The first and most obvious element of a false advertising claim is a plausible allegation of falsity.[4] Apotex Inc. v. Acorda Therapeutics, Inc., 823 F.3d 51, 63 (2d Cir. 2016). Falsity may be adequately alleged in two ways. First, a plaintiff may allege facts plausibly supporting literal falsity —that is, that an advertisement is false on its face. Id. In such a case, consumer deception is presumed. Id. "This inquiry requires evaluating 'the message conveyed in full context.'" Id. (quoting Time Warner Cable, Inc. v. DIRECTV, Inc., 497 F.3d 144, 153 (2d Cir. 2007). When read in context, if the words or images imply a false message, the advertisement is literally false. Id. However, only unambiguous messages can be
9 literally false. Id. *9 (citing Time Warner Cable, 497 F.3d at 158). A second way of adequately alleging falsity is to set forth facts plausibly supporting that the advertisement, while not literally false, is nevertheless likely to mislead or confuse consumers. Id. (citing Time Warner Cable, 497 F.3d at 153). To do this requires a comparison of the *impression* left by the statement (and not the statement itself) with the truth. Id.

4 Falsity, deception or other wrongful or inequitable conduct is also an element of each of the state law claims.

IV. DISCUSSION

Defendants seek dismissal on two separate and independent bases: first, that because plaintiff has failed to allege the specific products that failed its testing, it has failed to provide adequate notice under Rule 8 of the Federal Rules of Civil Procedure and has failed to allege a plausible set of facts entitling it to relief under Twombly. Second, defendants assert that plaintiff's allegations of falsity are inadequate as a matter of law. The Court agrees that both bases require dismissal.[5]

[5] As both of these issues apply to each of the state law claims, those claims are dismissed as well.

A. Lack of Adequate Specificity

Plaintiff has now twice amended its complaint. And twice it has failed to specify the precise products at issue in this lawsuit. This is a significant failing. See, e.g., Segedie v. Hain Celestial Grp., Inc., 14-cv-5029, 2015 WL 2168374, at *12 (S.D.N.Y. May 7, 2015) (finding a Lanham Act complaint to be insufficiently specific where it stated that the products falsely labeled include 'but are not limited to' the products listed by name in the complaint and allowing the claim to go forward only for those products which
10 had been specifically named). *10

As Board-Tech alleges in the SAC, it is a direct competitor with defendants for the manufacture and sale of light switches. (SAC ¶ 3.) Plaintiff alleges that it has tested a sampling of defendants' switches: eight sets of six light switches. Its claims, however, broadly encompass several product lines: the 7500, 7600, and 7700 series. Somewhere in this series of products are those that were specifically tested; they have not been identified. According to plaintiff, proceeding in this manner is akin to proceeding according to "sampling" that has been accepted in other cases.

Plaintiff misconceives the concept and use of "sampling." Under the circumstances here, the lack of specificity dooms plaintiff's claims under both Twombly and Rule 8. Here, plaintiff's claims are not, for instance, that very specific loan files may serve as samples of a larger set. See, e.g., Fed. Hous. Fin. Agency v. UBS Americas, Inc., 858 F. Supp. 2d 306, 324, 328 (holding that loan-sampling results were "sufficiently suggestive of widespread accuracies" to meet the plausibility standard, but only where the plaintiff pled with specificity as to certain loan files and then extrapolated to the whole). In contrast, Board-Tech has been non-specific as to any light switches at all.

Moreover, plaintiff has failed to state on what basis he can extrapolate from his few non-specific switches to entire product lines. Under Twombly, this Court cannot conclude that testing just six non-specific light switches provides a plausible
11 *11 basis upon which to tether claims as to more than 125 others.[6] To extrapolate in the manner that plaintiff has—from the relatively few to the many—plaintiff would need to have included sufficient facts to support a conclusion that because of similarities or characteristics of a particular nature, test results for certain switches are indicative of what similar tests would reveal for other products. There are no such allegations. Plaintiff simply (and without factual basis) asserts that its own limited testing is enough to make claim that "none" of defendants' "General-Use snap switches in Exhibit A" comply with UL 20. (SAC ¶ 48.)

[6] Plaintiff believes that the actual number of switches in the series is closer to 30, in a variety of colors. (Plaintiff's Opposition to Defendants' Motion ("Pl.s' Opp."), at 7.) Whether plaintiff seeks to extrapolate from six to 30 or from six to more than 100 does not change this Court's analysis that he has not alleged a factual basis for doing so. --------

In addition, failure to provide any allegations as to which product(s) within a broader product line failed is necessary in order for defendants to investigate the claim and prepare a defense. A complaint also provides important guidance as to what is likely to relevant discovery, and what is not. But by grouping all products in the three lines together - most of which were never tested - plaintiff fails to provide adequate notice.

Moreover, plaintiff was on notice of the instant Rule 8 and Twombly deficiencies when defendants filed their initial motion to dismiss, and when the Court discussed this issue at the initial conference. Despite having now twice amended the complaint, plaintiff has not remedied the issue. Its refusal to specify the particular products tested concerns the Court. It is plain that commencing such a broad lawsuit is a declaration of war on a competitor. If allowed to proceed in
12 *12 such a broad manner, plaintiff would no doubt seek access to the internal design of competitive products as well as highly sensitive technical data. Damages discovery would involve all of defendants' sales of this series of products.

Plaintiff has failed first to state with specificity which products failed UL testing, and then to provide factual allegations as to why those products' deficiencies can be extrapolated to other General Use snap switches. The Court therefore concludes that it has not pled with the specificity required by Rule 8 and Twombly.

B. A Lack of Falsity

As set forth above, the heart of a false advertising claim is falsity. Apotex, 823 F.3d at 63. Here, plaintiff alleges that inclusion of the UL certification mark conveys the false impression that defendants' light switches comply with UL 20. Plaintiff alleges that NRTLs "do not guarantee the products actually sold by a manufacturer comply with the applicable safety requirements; they only certify that a purportedly representative sample did." (SAC ¶ 29.) Plaintiff also acknowledges that each of defendants' products "have in fact been granted permission" to bear the UL mark, (SAC ¶ 32), and that "[a]ll of Defendants' light switches at issue in this case have been 'listed' or 'classified' by Underwriters Laboratories . . . ." (Id. ¶ 26).

Plaintiff's claim is based in the distinction between *authorization* to apply the UL mark and *actual compliance* with the standards referenced by the mark. As set forth above, plaintiff concedes authorization. It alleges, however, that despite such authorization, the products fail to comply
13 with the safety standards. (See SAC ¶¶ *13 30-31.) Looked at another way, plaintiff's claim is that even if defendants are authorized to use the mark, they are deceiving customers by using it. In support, it relies on Burndy Corp. v. Teledyne Indus., Inc., 748 F.2d 767, 774 (2d Cir. 1984), for the proposition that products bearing a UL mark can give rise to false advertising under the Lanham Act, and on Midwest Plastic Fabricators, Inc. v. Underwriters Laboratories, 906 F.2d 1568, 1569 (Fed. Cir. 1990) for the proposition that the responsibility of ensuring compliance remains with the manufacturer. (Holding that "the manufacturer agrees that it will ensure that the products bearing the UL mark are in compliance with [UL's] requirements" and that "a testing and inspection program will be maintained by the manufacturer to assure continued compliance.")

But plaintiff's reliance is misplaced; in Burndy, defendants had made changes to the advertised product after UL certification, never submitted those changed products to UL for testing, and continued to apply the UL mark. Burndy, 748 F.2d at 769. Plaintiffs notified UL of the problem, UL tested the new products and found them noncompliant, and only then did plaintiffs make their claim. Id. It was, in fact, the *unauthorized* use of the mark that allowed a Lanham Act claim to arise, and UL itself was the sole arbiter of whether the product in question was compliant. No such circumstances are alleged here. There are no allegations that defendants altered their products post-UL approval. Midwest Plastic, while finding a continuing obligation of manufacturer compliance with UL standards, goes on to define this compliance as, inter alia,
14 maintaining a testing and inspection program *14 to assure compliance and providing access to UL

inspectors. 906 F.2d at 1569-70. Plaintiff does not allege that Eaton has failed to maintain a testing and inspection program with regards to the Series 7500, 7600, or 7700 products. Rather, plaintiff's claim relies upon <u>its own</u> testing of the light switches—effectively attempting to supplant UL's responsibility to do so.

For plaintiff's theory to support a claim in this case, the *authorized* use of the mark must nonetheless be capable of being a deceptive use. It is not. The UL mark is limited by the scope of its registration. Its registration explicitly states that the "mark is used by persons authorized by applicant to indicate that representative samplings of the products conform to the safety requirements used by the applicant." (Turner Decl., Ex. 3, p. 2.) Defendants' use of the mark, as alleged by plaintiffs, indicates only that a representative sampling has conformed to the safety requirements; plaintiff here concedes that defendants' light switches went through United Laboratories' approval process. (SAC ¶ 32.)

It may be that plaintiff's own testing shows that certain of the light switches that bear the UL mark do not in fact comply with the safety standards. The Court accepts that allegation as true for purposes of this motion. But if defendants are authorized to apply the mark (which plaintiff concedes they are), then plaintiff is simply policing the mark. It is up to United Laboratories to police the mark. To the extent plaintiff believes that the mark has been diluted - or tarnished - by a failure to properly police it by United Laboratories, a remedy is available under 15 U.S.C. § 1064(5): plaintiff may seek to cancel the
15 mark. *15

A number of thorny issues would arise if this Court were to allow this action to proceed. First, it would allow a competitor to police a certification mark. Private testing of a product against standards could be used to commence a lawsuit that could expose competitive design and information to precisely the entity that should not have it. While there are many cases in which competitors are proper plaintiffs - and do obtain discovery - one should not open the floodgates to such litigation without careful consideration. Careful consideration here requires dismissal.

V. CONCLUSION

For the reasons set forth above, the Court GRANTS the motion to dismiss. The Clerk of Court is directed to close the motion at ECF No. 27 and to terminate this action.

SO ORDERED. Dated: New York, New York

October 31, 2017

<u>/s/__________</u>

KATHERINE B. FORREST

United States District Judge

Case No. 4:10CV645 CDP
UNITED STATES DISTRICT COURT EASTERN DISTRICT OF MISSOURI EASTERN DIVISION

Process Controls Int'l, Inc. v. Emerson Process Mgmt.

Decided Oct 22, 2012

Case No. 4:10CV645 CDP

10-22-2012

PROCESS CONTROLS INTERNATIONAL, INC., d/b/a AUTOMATION SERVICE, Plaintiff, v. EMERSON PROCESS MANAGEMENT, et al., Defendants.

CATHERINE D. PERRY

MEMORANDUM AND ORDER

Pending before me are numerous motions for summary judgment by all parties. I will grant in part and deny in part the motions for the reasons discussed below. This case remains set for trial on the two-week docket beginning December 3, 2012.

Undisputed Facts

Defendant Emerson[1] is an original equipment manufacturer (OEM) of process control equipment, which is used to control and/or regulate the flow of hazardous substances through piping systems. Plaintiff is Process Controls International, Inc., doing business as Automation
2 Service (Automation). *2

1 Emerson Process Management, Fisher Controls, International, LLC, and Rosemount, Inc. are all entities within the Emerson company.

Automation and several other companies, including Emerson through its Encore brand, remanufacture the process control equipment because some consumers prefer to replace their worn-out equipment with used, but remanufactured equipment rather than brand-new equipment.[2] Factory Mutual Insurance Company insures industrial companies that use process control equipment. Its subsidiary, defendant FM Approvals, LLC has established safety standards for these companies and certifies certain process control equipment as "FM approved" if it satisfies those safety standards. Many Emerson products are FM approved and bear the FM Approvals trademark. Automation has not been approved as a repairer of process control equipment by FM Approvals.

2 Whether Automation reconstructs or repairs the process control equipment is a legal question discussed more fully below. I use the word "remanufacture" here to reflect the parties' pleadings, but in no way intend its use to imply any legal conclusions regarding Automation's activities.

When Automation remanufactures Emerson equipment, it sometimes leaves the Emerson and FM Approvals trademarks on the equipment. This practice has led to on-going disputes between Emerson and Automation, with Emerson contending that Automation is wrongfully using Emerson's trademarks, and Automation contending that Emerson unfairly keeps it from competing in the marketplace for remanufactured Emerson products. The latest iteration of this dispute ended with a settlement agreement
3 between the parties and a release of *3 their claims against one another for any activities that occurred before December 3, 2007.

Legal Standard

The standards for summary judgment are well settled. In determining whether summary judgment should issue, the court must view the facts and inferences from the facts in the light most favorable to the nonmoving party. *Matsushita Elec. Indus. Co. Ltd. v. Zenith Radio Corp.,* 475 U.S. 574, 587 (1986). The moving party has the burden to establish both the absence of a genuine issue of material fact, and that it is entitled to judgment as a matter of law. Fed. R. Civ. P. 56(c); *Anderson v. Liberty Lobby Inc.,* 477 U.S. 242, 247 (1986); *Celotex Corp. v Catrett,* 477 U.S. 317, 322 (1986). Once the moving party has met this burden, the nonmoving party may not rest on the allegations in the pleadings but must set forth by affidavit or other evidence specific facts showing that a genuine issue of material facts exists. Fed. R. Civ. P. 56(e). At the summary judgment stage, I will not weigh evidence and decide the truth of the matter, but rather I need only determine if there is a genuine issue of material fact. *Anderson,* 477 U.S. at 249.

Discussion

I. Automation's Claims for False Advertising, Tortious Interference, and Defamation

4 *4

Emerson has moved for summary judgment as to counts 9, 10, and 11 of Automation's third amended complaint. These three counts are brought against Emerson, and allege, respectively, false advertising, tortious interference with business expectancy, and defamation. Automation alleges that Emerson has falsely and publicly asserted that products remanufactured by Emerson are safer than products remanufactured by Automation.

A. Claims arising before December 2007 are barred by the settlement agreement between the parties.

Automation and Emerson entered into an agreement, effective December 3, 2007, to settle all claims related to a prior lawsuit between the parties. That agreement contains a release that states, in part:

> Automation Service . . . hereby releases and forever discharges Fisher[3] . . . from any and all manner of claims, causes of action, demands for arbitration or mediation, or other manner of action, formal or informal, whether known or unknown, of every nature and type whatsoever that they may have heretofore had, now have, or, but for this Agreement, might hereafter have had against Fisher . . . connected with, resulting from, or arising out of:
>
> (i) any and all transactions or occurrences that were alleged or could have been alleged in the aforesaid Complaint, Automation Service's answer to the Complaint, or any counterclaim brought in response to the Complaint; and/or
>
> 5 *5
>
> (ii) any and all transactions or occurrences between Fisher and Automation Service that have occurred before the date of this Agreement;

Docket No. 7 at 11-12.

3 Fisher entered the Agreement on behalf of all "Fisher-Related Companies," which the Agreement defines as "Fisher; Fisher Rosemount Systems, Inc.; Rosemount, Inc.; Emerson Electric Co.; any other company in which Fisher owns a controlling interest; any other company that owns a controlling interest in Fisher; and any other company owned or controlled - directly or indirectly - by, or under common control with, Fisher or Fisher's parent, Emerson Electric Co."

Automation's expert witness, in calculating damages for these counts, included in his analysis some statements from Emerson allegedly made or received before December 3, 2007. Automation argues that even though the statements were made before December 3, 2007, it can recover if some of the damages arose after that date. It also says that the claims now asserted were "unknowable" at the time of the settlement and therefore not waived by the release. Docket No. 285 at 11-12. This position is in complete contradiction to the plain language of the settlement agreement. *See Grant Cnty. Sav. & Loan Ass'n, Sheridan, Ark. v. Resolution Trust Corp.,* 968 F.2d 722, 724 (8th Cir. 1992) (holding that language in a release must be given its plain, ordinary meaning). All of Automation's claims arising from pre-December 2007 statements are therefore barred by the release.

B. Automation has not produced sufficient evidence to prove damages.

Each of counts 9 through 11 requires a showing of damages. *See Rusk Farms, Inc. v. Ralston Purina Co.,* 689 S.W.2d 671, 679 (Mo. Ct. App. 1985) (tortious interference); *Nazeri v. Mo. Valley College,* 860 S.W.2d 303, 313 (Mo. 1993) (defamation); *Porous Media Corp. v. Pall Corp.,*
6 110 F.3d 1329, 1336 (8th *6 Cir. 1997) (false advertising). To support this element of its claims, Automation has produced evidence of lost profits in the form of an expert report by Michael Prost.

To recover lost profits damages, the plaintiff must produce evidence that "provides an adequate basis for estimating the lost profits with reasonable certainty." *Ameristar Jet Charter, Inc. v. Dodson Int'l Parts, Inc.,* 115 S.W.3d 50, 54-55 (Mo. 2005). The plaintiff must establish with reasonable certainty "both that the defendant's actions caused the plaintiff to lose profit and the amount of those damages." *Metro. Express Servs., Inc. v. City of Kansas City, Mo.,* 71 F.3d 273, 275 (8th Cir. 1995).

Automation has not produced evidence to show with reasonable certainty that Emerson's statements caused any of Automation's customers to reduce their business with Automation. The only evidence Automation has produced is Prost's damages report. While Prost relied on some letters, emails, and articles written by Emerson, there is little evidence that any of Automation's customers received, reviewed, or took action based on the communications.[4]

[4] Many of the communications also predate December 3, 2007, and thus cannot provide a basis for any damages, as discussed above.

Automation relies on Prost's report to show that its sales to customers dropped after the point of alleged contact. However, Prost's report does not
7 prove *7 causation; in fact, it assumes it. Docket No. 259-2 at 4 ("The assumption that I made was that due to the contact of the customer, sales suffered . . . I was not asked to do anything on the causation side"). Automation also relies on *Rusk Farms* to argue that causation can be inferred since Automation had an ongoing business relationship with customers and sales dropped after the dates of alleged contact. The evidence does not support this inference. In *Rusk Farms,* there was evidence that customers actually received a letter from defendants, that the letter explicitly warned the customers that the turkeys at issue were already under contract, and that those customers then did not buy the turkeys; sales completely ceased immediately after each customer received the letter. 689 S.W.2d at 680. But here Automation has not produced evidence sufficient to show that any customers received, reviewed, or relied on the alleged contacts from Emerson. Even if the communications were received by Automation's customers, the communications were much less specific than those in *Rusk Farms.* And the sales trend lines produced by Automation show that after the date of contact there was not a complete cessation of sales. Rather, sales to some customers show a

show decline, while others even show an increase. Docket No. 284-4. Automation has thus not provided sufficient evidence to show causation of damages.

I will therefore grant Emerson's motion for summary judgment with regard to counts 9
8 through 11 of Automation's complaint. *8

II. Emerson's Patent Infringement Claims

Both Automation and Emerson have moved for summary judgment on counts 5 and 6 of Emerson's fourth amended counterclaim. Counts 5 and 6 allege that Automation infringes U.S. patents 7,516,043 and 5,532,925, respectively, by remanufacturing the DVC6000 series digital valve controllers. Automation does not dispute that the '043 and '925 patents read on the remanufactured DVC6000 controllers, nor does it challenge the validity of the patents. The only issue for summary judgment is whether Automation's activities constitute permissible repair that do not infringe the patent. "Whether a defendant's actions constitute a permissible repair or an infringing reconstruction is a question of law." *Aktiebolag v. E.J. Co.,* 121 F.3d 669, 672 (Fed. Cir. 1997).

The Supreme Court has defined when repair activities infringe a patent: Impermissible "reconstruction of a patented entity, comprised of unpatented elements, is limited to such a true reconstruction of the entity as to in fact make a new article after the entity, viewed as a whole, has become spent." *Aro Mfg. Co., Inc. v. Convertible Top Replacement Co., Inc.,* 365 U.S. 336, 345 (1961) (internal citations and quotations omitted). The courts have taken an expansive view of what constitutes permissible repair.

In *General Electric Company v. United States,* 572 F.2d 745 (Ct. Cl. 1978), the court held that the U.S. Navy's activities regarding a gun mount for
9 its ships *9 constituted permissible repair. *Id.* at 784. The Navy took decades-old gun mounts, sent them to a factory, overhauled the sixty percent of mounts that were serviceable, and scrapped the remaining forty percent for parts. *Id.* at 780. The mounts were reduced to their smallest separable parts, and those parts which could not be repaired were replaced, mostly by parts previously obtained from plaintiff G.E. *Id.* Parts such as seals, bearings, and wiring were also replaced, though the court did not identify the source of those parts. *Id.* The parts were reassembled with no attempt to return them to the gun mounts from which they were originally taken, nor were the mounts necessarily sent to their original ships. *Id.* at 781. The court held that applying this process to a single gun mount would constitute permissible repair, and so use of the assembly-line method "was simply a speedier, less expensive, more efficient, and more effective means of refurbishing the gun mounts," and was thus permissible. *Id.* at 786.

A similar conclusion was reached in *Dana Corporation v. American Precision Company, Inc.,* 827 F.2d 755 (Fed. Cir. 1987). In *Dana Corp.,* the alleged infringer acquired worn truck clutches as trade-ins, which it then disassembled, cleaned, sorted into bins, and reassembled using a production-line process. *Id.* at 756-77. When there were insufficient parts in the bins, new parts were used. *Id.* at 757. As in *General Electric,* the court held that "use of the production-line *method* cannot convert . . . permissible repair to
10 impermissible *10 reconstruction." *Dana Corp.,* 827 F.2d at 759 (emphasis in original). Further, in determining whether the trade-in clutches were "spent," the court held that it was the physical characteristics of the worn clutch that mattered, and not the owner's evaluation of the clutch's condition or economic value. *Id.* at 760.

The basics of Automation's remanufacture process are undisputed. Automation obtains used or inoperative DVC6000 controllers from third-party users. Automation disassembles the controllers, tests the parts, and discards those that do not work or are beyond repair. Salvageable parts are cleaned and placed in bins. When a customer wants a

DCV6000 controller, the necessary parts are removed from the bins, assembled, and sold and delivered to the buyer. Some hardware, such as nuts, bolts, screws, gaskets, o-rings, glass, and gauges are purchased from third parties as needed. This process is comparable to both *General Electric* and *Dana Corp.*

Nonetheless, Emerson argues that Automation commits impermissible repair for four reasons: (1) Automation admits in its pleadings and marketing materials that it reconstructs rather than repairs equipment; (2) Automation procures parts from third-party vendors; (3) the controllers procured by Automation are "spent;" and (4) Automation customizes its orders for customers. First, Emerson points to Automation's pleadings and marketing materials as judicial admissions that its activities constitute impermissible reconstruction.
11 *See,* *11 *e.g.* Docket No. 183 at ¶ 14 ("Remanufacture is different than repair"); Docket No. 252-5 at 16 ("Instead of simply repairing your old unit, have us remanufacture your units"). Judicial admissions pertain only to matters of fact. *State Farm Mut. Auto Ins. Co. v. Worthington,* 405 F.2d 683, 686 (8th Cir. 1968). The repair versus reconstruction issue is a question of law. *Aktiebolag v. E.J. Co.,* 121 F.3d at 672. Furthermore, there is nothing in any of Automation's materials that indicates the distinction between repair and remanufacture was intended to connote a technical legal attribution, rather than a practical way of distinguishing between degrees of repair. *See Vogrin v. Hedstrom,* 220 F.2d 863, 866 (8th Cir. 1955); *General Electric,* 572 F.2d at 779 (U.S. Navy differentiated between varying degrees of maintenance, all of which were held to constitute permissible repair).

Regarding Automation's procurement of parts from third parties, Emerson relies on *General Electric* to argue that this takes Automation's activities outside the realm of permissible repair. In holding that the Navy conducted permissible repair on its gun mounts, the court noted as a "significant fact" that "Of the 17 elements of the patented combination . . . G.E. appears to have itself supplied the defendant . . . with at least fifteen elements." *Id.* at 781. Even though this fact was "cardinal" to the court's decision, *id.* at 782, *General Electric* does not require that every replacement item be purchased from the patentee,
12 as Emerson suggests. *12 The use by Automation of third-party nuts, bolts, screws, gaskets, o-rings, glass, and gauges therefore does not transform an otherwise permissible repair into an impermissible reconstruction.

Emerson also argues that the DCV6000 controllers remanufactured by Automation are "spent." It is undisputed that Automation acquires the controllers it remanufactures from third parties who have discarded them or placed them in scrap bins. Other controllers were recovered after being damaged in Hurricane Katrina, and were full of salt water and heavily corroded. Docket No. 254-5 at 2. However, neither of these sets of controllers are "spent" as defined by the caselaw. *See Aro Manufacturing,* 365 U.S. at 345. In *Dana Corp.,* used clutches were also recovered through a reclamation program from third-party users. 827 F.2d at 760. The court dismissed the plaintiff's argument that "whether the patented product is 'spent' should turn on the owner's economic evaluation of the product, rather than on an examination of its physical characteristics." *Id.* Additionally, the corrosion and flooding of the Katrina-recovered controllers does not make them "spent." *See Wilbur-Ellis Co. v. Kuther,* 377 U.S. 422 (1964). In *Wilbur-Ellis,* a second-hand purchaser recovered fish-packing machines that were "corroded, rusted, and inoperative," and returned them to working condition. *Id.* at 423. The Court held that they were not spent, reasoning, "They had years of usefulness remaining though they needed cleaning and
13 repair." *Id.* at 424. *13

In *Aktiebolag,* the court found that replacement of a drill tip constituted impermissible repair because the drill tip was not manufactured to be a replaceable part, there was no evidence of a substantial market for retipping, and the patentee never intended for its drills to be retipped. *Id.* at 674. But in this case, Emerson's controllers have readily replaceable parts, there is a substantial market for the repaired products, and Emerson must have intended for the controllers to be repaired in this manner, since it itself if one of several companies doing the same type of repairs as Automation.

Finally, Emerson cites no cases to support its position that customization indicates impermissible reconstruction, but instead relies on the testimony of its expert, Dr. Albert Karvelis. Dr. Karvelis's testimony is ultimately a legal analysis, and is therefore inadmissible. *See S. Pine Helicopters, Inc. v. Phoenix Aviation Managers, Inc.,* 320, F.3d 838, 841 (8th Cir. 2003). The actual caselaw does not support this position. For instance, in *Wilber-Ellis,* the machines had originally been constructed to pack fish into one-pound cans, but were remanufactured to pack fish into five-ounce cans. 377 U.S. at 423. Nonetheless, the Court held that, "Petitioners in adapting the old machines to a related use were doing more than repair in the customary sense; but what they did was kin to repair for it bore on the useful capacity of the old combination." *Id.* at 425.
14 Similarly here, Automation's *14 customization of the DVC6000 controllers does nothing more than "bear on the useful capacity of the old combination."

For the reasons stated above, I conclude that Automation's activities amount to permissible repair of the DVC6000 controllers as a matter of law. I will therefore grant Automation's motion for summary judgment as to counts 5 and 6 of Emerson's counterclaims, and will deny Emerson's motion for summary judgment as to the same counts.

III. Emerson's Trademark Claim

Automation has moved for summary judgment on count 2 of Emerson's counterclaims, which alleges trademark infringement under the Federal Lanham Act. Emerson alleges that Automation offers remanufactured equipment bearing Emerson-owned trademarks. In moving for summary judgment, Automation argues that it is allowed to retain the trademark under *Champion Spark Plug Co. v. Sanders,* 331 U.S. 125 (1947). Automation argues that its activities amount to permissible repair, that it clearly indicates that the items have been repaired, and that the sophisticated consumers of process controls equipment are not likely to be confused by the presence of the trademark.

In *Champion,* the Court upheld the Second Circuit's decree allowing defendant to retain plaintiff's trademark on its refurbished spark plugs so long as they were clearly marked as "repaired."
15 *Id.* at 127-28. While the Court *15 acknowledged that, "Cases may be imagined where the reconditioning or repair would be so extensive or so basic that it would be a misnomer to call the article by its original name, even though the words 'used' or 'repaired' were added," it held that in the case at hand, the repair of the spark plugs "did not give them a new design" and was "no more than a restoration." *Id.* at 129. Other cases have held that the trademark cannot be retained when defendant's actions result in a "new construction," *Bulova Watch Co. v. Allerton Co.,* 328 F.2d 20, 23 (7th Cir. 1964), or are "structurally different." *Schütz Container Sys., Inc. v. Mauser Corp.,* 1:09CV3609 RWS, 2012 WL 1073153, at *21 (N.D. Ga. Mar. 28, 2012).

Despite Automation's argument to the contrary, this is not an identical test to the permissible repair/impermissible reconstruction question that applies in patent cases. Thus, my holding that Automation's activities constitute permissible repair under *Aro* does not automatically entitle it to judgment on the trademark infringement claims. While the patent cases are chiefly concerned with the physical condition of the invention, *Dana Corp.,* 827 F.2d at 760, *Champion* ultimately turns on the issue, central to trademark law, of whether "the unauthorized use was likely to deceive, cause

confusion, or result in mistake." *Nitro Leisure Prods., LLC v. Acushnet Co.,* 341 F.3d 1356, 1359, 1361 (Fed. Cir. 2003); *Champion,* 331 U.S. at 129. The *Champion* line of cases is concerned both with the nature of the repaired product and any
16 disclaimer notifying customers of *16 its repaired nature. *Champion,* 331 U.S. at 130; *Nitro,* 341 F.3d at 1364; *Bulova,* 328 F.2d at 23-24. This analysis is very fact-specific. The evidence produced in this case shows that Automation does not repair every item in an identical manner, nor are the same disclaimers used for every product.

Genuine issues of material fact remain regarding Automation's alleged trademark infringement, and so I will deny Automation's motion for summary judgment as to count 2 of Emerson's counterclaims.

IV. Emerson's Other Claims Against Automation

Automation also seeks summary judgment on Counts 1, 3, 4, 7, and 8 of Emerson's fourth amended counterclaims. These counts claim, respectively, breach of contract, unfair competition under the Federal Lanham Act, false advertising under the Federal Lanham Act, unfair competition under Missouri state law, and misappropriation of trade secrets. After carefully reviewing the parties' submissions, I find that genuine issues of material fact remain on all of theses claims. I will therefore deny Automation's motions for summary judgment as to counts 1, 3, 4, 7, and 8 of Emerson's fourth amended counterclaims.

V. FM Approvals' Certification Mark

Both FM Approvals and Automation have moved for summary judgment on counts 1—4 of FM Approvals' counterclaim. FM Approvals seeks summary judgment as to liability only. All counts
17 stem from Automation's use of the FM *17 Approvals certification marks on its remanufactured process controls equipment. In Count 1 FM Approvals seeks a declaratory judgment regarding the alleged trademark violation, and in counts 2, 3, and 4 it alleges, respectively, trademark infringement, unfair competition under the Federal Lanham Act, and unfair competition under Missouri state law. FM Approvals has also moved for summary judgment on count 12 of Automation's complaint for declaratory judgment.[5]

[5] Automation's count 12 is brought against both FM Approvals and Emerson, but only FM Approvals has moved for summary judgment on this count.

FM Approvals is a Nationally Recognized Testing Laboratory (NRTL), authorized by the U.S. Occupational Safety and Health Administration to test and certify certain process controls equipment as safe for use in the U.S. workplace. As such, FM Approvals has provided for three ways to ensure that repaired equipment remains compliant with its certification standards: repair by the OEM, repair by an independent repair facility under FM Approval's Standard 3606, or repair by an end user that has been approved under 3606. Docket No. 179-6, 179-30. Notably, all three of these methods involve an audit or inspection of the repair facilities and processes by FM Approvals. *Id.*; Docket No. 275-7 at 6-7. Automation does not claim that it has been approved by FM Approvals as a producer or repairer of process control
18 equipment, but rather argues that as an *18 owner of the equipment it is entitled to repair it according to the OEM's manual without voiding the equipment's FM Approvals certification. Automation further argues that its repaired equipment meets the FM Approvals certification standards. This is not the issue; the FM Approvals certification mark does not simply represent the quality of the equipment, but the fact that FM Approvals has in fact inspected the equipment, facility, or repair processes and approved it. Docket No. 275-7 at 6-7. Not only does Automation's argument ignore the process for repair approvals, it would completely undermine

the value of the certification system, which relies on testing and oversight by a NRTL such as FM Approvals.

Automation also argues that even if its equipment can no longer be classified as "FM Approved," Automation is entitled to retain the FM Approvals mark under *Champion.* I disagree. As discussed above, in *Champion,* the Court held that the defendant could retain plaintiff's trademark on its remanufactured sparkplugs in light of the fact that they were clearly disclaimed as being "repaired." 331 U.S. at 127-28. Central to this decision was the fact that because "inferiority is expected in most second-hand articles . . . [i]nferiority is immaterial so long as the article is clearly and distinctively sold as repaired or reconditioned." *Id.* at 129-30. However, certification marks are different in nature from other trademarks. *See, e.g., Idaho Potato Comm 'n v. G&T Terminal Packaging, Inc.,* 425 F.3d 708, 716 (9th Cir. 2005). Disclosing that an item is "repaired" may
19 *19 effectively inform a consumer of the product's nature as compared to a new item of the same origin. However, simply disclosing that an item is "repaired" does not similarly inform a consumer that the repair process has not been re-audited by the holder of the certification mark it bears. *See id.* at 721 ("In the certification mark context, the mark holder's ability to institute quality controls seems vital if a mark is to serve its purpose"). *Champion* does not protect Automation's activities with regard to the FM Approvals certification mark.

Accordingly, Automation's activities were "likely to cause confusion, or to cause mistake, or to deceive." *See SquirtCo. v. Seven-Up Co.,* 628 F.2d 1086, 1090-91 (8th Cir. 1980). FM Approvals has produced evidence not only of likely confusion, but of actual customer confusion. *See, e.g.,* Docket No. 267-21 at 3-4, 7, 10; 267-33 at 5; 267-36 at 5-6. Automation does not dispute this evidence except to argue that no confusion could exist because its products are, in fact, still allowed to be marketed as FM Approved even though FM Approvals has not actually approved the repairs or Automation's facilities or systems for making those repairs. While the parties argue over which standards and factors should be used in evaluating likelihood of confusion, the evidence of actual confusion makes those arguments moot. *SquirtCo.,* 628 F.2d at 1091 ("Actual confusion is not essential to a finding of trademark infringement, although it is positive proof of
20 likelihood of confusion"). *20

Finally, Automation argues that it is entitled to summary judgment on FM Approvals' declaratory judgment action, relying on a recent case where I stated that, "The purpose of the Declaratory Judgment Act . . . in patent cases is to provide the allegedly *infringing party* relief." *American Piledriving Equipment, Inc v. Hammer & Steel, Inc.,* 4:11CV811 CDP, 2012 WL 1414837, at *3 (Apr. 24, 2012) (internal citations omitted) (emphasis added). It is true that when FM Approvals - the trademark owner - brought this declaratory judgment claim, it reversed the roles of the parties in a typical declaratory judgment action. *See Geisha, LLC v. Tuccillo,* 525 F. Supp. 2d 1002, 1010 (N.D. Ill. 2007). Nonetheless, such declaratory judgment actions are still available if "the facts alleged, under all the circumstances, show that there is a substantial controversy, between parties having adverse legal interests, of sufficient immediacy and reality to warrant the issuance of a declaratory judgment." *MedImmune, Inc. v. Genentech, Inc.,* 549 U.S. 118, 127 (2007)); *Geisha,* 525 F. Supp. 2d at 1013. This is not a case of uncertain prospective infringement - here the evidence shows that there is a real possibility of infringing activity going forward. *See Geisha,* 525 F. Supp. 2d at 1018. Nor is this a case, like *American Piledriving,* where the intellectual property owner is barred from recovering damages and a declaration would have no practical effect. 2012 WL 1414837 at *3. Accordingly, declaratory
21 judgment is appropriate. *21

For the reasons stated above, I will grant FM Approvals' motion for summary judgment on liability for counts 2 through 4 of its counterclaims. The issue of damages under those counts remains for trial. I will also grant FM Approvals' motion for summary judgment for declaratory judgment under count 1 of its counterclaims. I will deny Automation's motion for summary judgment as to counts 1 through 4 of FM Approvals' counterclaims. I will grant FM Approvals' motion for summary judgment dismissing count 12 of Automation's complaint for declaratory judgment, only as to defendant FM Approvals.

Conclusion

The following claims remain for trial. From Automation's third amended complaint: count 12 for declaratory judgment, against defendant Emerson only. From Emerson's fourth amended counterclaim: count 1 for breach of contract, count 2 for trademark infringement, count 3 for unfair competition under the Federal Lanham Act, count 4 for false advertising under the Federal Lanham Act, count 7 for unfair competition under Missouri state law, and count 8 for misappropriation of trade secrets. From FM Approvals' counterclaim, damages only on each count: count 2 for trademark infringement, count 3 for unfair competition under the Federal Lanham Act, and count 4 for unfair competition under Missouri state law.

22 Accordingly, *22

IT IS HEREBY ORDERED that Emerson's motion for summary judgment [#251] as to counts 5 and 6 of Emerson's fourth amended counterclaim is denied.

IT IS FURTHER ORDERED that Automation's motion for summary judgment [#256] as to counts 1-7 of Emerson's fourth amended counterclaim is granted as to counts 5 and 6 only, and is denied in all other respects.

IT IS FURTHER ORDERED that Emerson's motion for summary judgment [#257] as to counts 9-11 of Automation's third amended complaint is granted.

IT IS FURTHER ORDERED that Automation's motion for summary judgment [#262] as to counts 1-4 of Factory Mutual's counterclaim is denied.

IT IS FURTHER ORDERED that Automation's motion for summary judgment [#264] as to count 8 of Emerson's fourth amended counterclaim is denied.

IT IS FURTHER ORDERED that Factory Mutual's motion for summary judgment [#266] as to counts 1-4 of Factory Mutual's counterclaim and count 12 of Automation's third amended complaint is granted.

CATHERINE D. PERRY

UNITED STATES DISTRICT JUDGE

Sunrise Energy, LLC v. PPL Corp.

Decided Mar 27, 2015

2:14cv618

03-27-2015

SUNRISE ENERGY, LLC, Plaintiff, v. PPL CORPORATION and PPL ELECTRIC UTILITIES CORPORATION, Defendants.

David Stewart Cercone United States District Judge

Electronic Filing

OPINION

Sunrise Energy, LLC ("plaintiff") commenced this action against PPL Corporation ("PPL") and PPL Electric Utilities Corporation ("PPLEU") (collectively "defendants") seeking redress for defendants' alleged violation of constitutional rights in denying or failing to approve plaintiff's applications made pursuant to Pennsylvania's Alternative Energy Portfolio Standards Act, 73 Pa. Cons. Stat. §§ 1648.1-1648.8 (the "Act"). Plaintiff asserts claims under the Civil Rights Act of 1871, as amended, 42 U.S.C. § 1983, for deprivation of its substantive due process and equal protection rights in violation of the Fourteenth Amendment and state law claims for tortious interference, unfair competition, direct violation of the Act and declaratory judgment. Presently before the court is defendants' motion to dismiss under Federal Rule of Civil Procedure 12(b)(6). For the reasons set forth below, the motion will be granted.

It is well-settled that in reviewing a motion to dismiss under Federal Rule of Civil Procedure 12(b)(6) "[t]he applicable standard of review requires the court to accept as true all allegations in the complaint and all reasonable inferences that can be drawn therefrom, and view them in the light most favorable to the non-moving party."
2 Rocks v. City of Philadelphia, 868 *2 F.2d 644, 645 (3d Cir. 1989). Under the Supreme Court's decision in Bell Atlantic Corp. v. Twombly, 550 U.S. 544 (2007), dismissal of a complaint pursuant to Rule 12(b)(6) is proper only where the averments of the complaint plausibly fail to raise directly or inferentially the material elements necessary to obtain relief under a viable legal theory of recovery. Id. at 555-56. In other words, the allegations of the complaint must be grounded in enough of a factual basis to move the claim from the realm of mere possibility to one that shows entitlement by presenting "a claim to relief that is plausible on its face." Ashcroft v. Iqbal, 556 U.S. 662, 678 (2009) (quoting Twombly, 550 U.S. at 570).

"A claim has facial plausibility when the plaintiff pleads factual content that allows the court to draw the reasonable inference that the defendant is liable for the misconduct alleged." Id. In contrast, pleading facts that only offer "'labels or conclusions' or 'a formulaic recitation of the elements of a cause of action will not do,'" nor will advancing only factual allegations that are merely consistent with a defendant's liability. Id. (quoting Twombly, 550 U.S. at 555). Similarly, tendering only "naked assertions" that are devoid of "further factual enhancement" falls short of presenting sufficient factual content to permit an inference that what has been presented is more than a mere possibility of misconduct. Id. at 678; see also Twombly, 550 U.S. at 563 n.8 (A complaint states a claim where its factual

averments sufficiently raise a "'reasonably founded hope that the [discovery] process will reveal relevant evidence' to support the claim.") (quoting Dura Pharmaceuticals, Inc. v. Broudo, 544 U.S. 336, 347 (2005) (quoting Blue Chip Stamps v. Manor Drug Stores, 421 U.S. 723, 741 (1975))); accord Morse v. Lower Merion School Dist., 132 F.3d 902, 906 (3d Cir. 1997) (a court need not credit "bald assertions" or "legal conclusions" in assessing a motion to dismiss) (citing with approval Charles Alan Wright & Arthur R. Miller, FEDERAL PRACTICE AND
3 PROCEDURE § 1357 (2d ed.1997) ("courts, *3 when examining 12(b)(6) motions, have rejected 'legal conclusions,' 'unsupported conclusions,' 'unwarranted inferences,' 'unwarranted deductions,' 'footless conclusions of law,' or 'sweeping legal conclusions cast in the form of factual allegations.'").

This is not to be understood as imposing a probability standard at the pleading stage. Iqbal, 556 U.S. at 678 ("The plausibility standard is not akin to a 'probability requirement,' but it asks for more than a sheer possibility that a defendant has acted unlawfully."); Phillips v. County of Allegheny, 515 F.3d 224, 234 (3d Cir. 2008) (same). Instead, "[t]he Supreme Court's Twombly formulation of the pleading standard can be summed up thus: stating a claim requires a complaint with enough factual matter (taken as true) to suggest the required element. . . . [and provides] enough facts to raise a reasonable expectation that discovery will reveal evidence of the necessary element." Phillips, 515 F.3d at 234; see also Wilkerson v. New Media Technology Charter School Inc., 522 F.3d 315, 321 (3d Cir. 2008) ("'The complaint must state enough facts to raise a reasonable expectation that discovery will reveal evidence of the necessary element.'") (quoting Phillips, 515 F.3d at 234) (internal citations omitted). "[O]nce a claim has been stated adequately, it may be supported by showing any set of facts consistent with the allegations in the complaint." Twombly, 550 U.S. at 563.

The record read in the light most favorable to plaintiff establishes the background set forth below. Sunrise Energy LLC "was founded with the mission of developing and operating solar power facilities that serve as customer-generators under the Act." (Complaint at ¶ 24). According to its preamble, the Act was intended to provide "for the sale of electric energy generated from renewable and environmentally beneficial sources, for the acquisition of electric energy generated from renewable and environmentally beneficial sources by electric distribution and supply companies and for the powers and duties of the Pennsylvania
4 Public Utility *4 Commission" (the "PUC"). 2004 Pa. Legis. Serv. Act 2004-213 (S.B. 1030). In pursuit of these goals, the Act implemented certain milestones for the minimum utilization of alternative energy sources by electric distribution companies ("EDCs") and electric generation suppliers. 73 Pa. Cons. Stat § 1648.3.

Relevant to the instant matter, the Act provides for "net metering," which is defined as "[t]he means of measuring the difference between the electricity supplied by an electric utility and the electricity generated by a customer-generator when any portion of the electricity generated by the alternative energy generating system is used to offset part or all of the customer-generator's requirements for electricity."[1] 73 Pa. Cons. Stat. § 1648.2. The Act defines a "customer-generator" primarily as "[a] nonutility owner or operator of a net metered distributed generation system." 73 Pa. Cons. Stat. § 1648.2.

[1] Under the Act, alternative energy generating systems include those that utilize solar, wind and geothermal energy. 73 Pa. Cons. Stat. § 1648.2.

In short, net metering permits a customer-generator to sell any cumulative yearly excess of energy generated by an alternative energy system back to its EDC, receiving "full retail value for all energy produced." 73 Pa. Cons. Stat. § 1648.5. The PUC was tasked with promulgating the rules that would govern this practice. Id.

After adopting a final rulemaking order on June 22, 2006, the PUC's first set of regulations took effect on December 15, 2006. 36 Pa. Bull. 7574. After amendment, the present form of these regulations became effective on November 29, 2008. 52 Pa. Code §§ 75.1-75.70 (the "Regulations").

On February 20, 2014, the PUC issued a proposed rulemaking order recommending extensive revisions to the regulations governing net metering. See 44 Pa. Bull. 4179. These changes have yet to take effect. See 44 Pa. Bull. 6730. The
5 proposed changes include *5 requirements that (1) customer-generators have a need for electricity beyond what is needed to operate the alternative energy system (a "non-generational load") and (2) alternative energy systems be sized to generate no more than 110 percent of the customer-generator's annual electric consumption. 44 Pa. Bull. 4179. These changes would not affect the general process under which a customer wishing to net meter must seek approval from its EDC to do so. 52 Pa. Code § 75.32.

Plaintiff has operated one 950 kilowatt solar power facility utilizing the Act's current net metering provisions since 2010 in the service territory of EDC West Penn Power. (Complaint at ¶ 26). Desiring to construct an additional 1.95 megawatt facility in 2014, plaintiff investigated three potential sites. PPLEU was the EDC for each of these sites. (Id., at ¶¶ 29, 32, 34). These properties were located in Beavertown, East Berwick, and Beach Haven, Pennsylvania. (Id., at ¶ 30).

Plaintiff submitted its first application for net metering to PPLEU for the Beavertown property on March 11, 2014. (Doc. No. 1-2, at p. 3). PPLEU denied this application on March 25, 2014, explaining that the proposal did not meet the intent of the Act due to the absence of a "non-generational load." (Doc. No. 1-5, at p. 1). Plaintiff then filed its second and third applications on March 30 and April 16, 2014, for the East Berwick and Beach Haven sites. (Doc. Nos. 1-3, at p. 3; 1-4, at p. 3). PPLEU did not deny these applications, but instead responded by issuing separate letters for each of plaintiff's three applications. These letters explained that "substantial uncertainty regarding the requirements to qualify as a 'customer-generator'" made it unclear whether each application qualified
6 for net metering.[2] (Doc. Nos. 1-6, *6 1-7, 1-8). These letters further advised that PPLEU intended to file a pleading with the PUC seeking determinations on plaintiff's applications. (Id.). Plaintiff has been unable to move forward with any of its proposed projects, as each is contingent upon receiving approval to net meter. (Complaint at ¶¶ 33, 45).

2 These letters were sent as attachments to emails and were undated. The email attaching the letters for the Beavertown and East Berwick applications was sent on April 14, 2014. (Doc. No. 13-3, at p. 2). The letter in response to the Beach Haven application was attached to an email sent on April 30, 2014. (Id., at p. 7).

PPLEU filed a petition with the PUC on May 9, 2014, seeking a declaratory order to resolve its uncertainty as to the ability of plaintiff and another similar applicant to take part in net metering. (Doc. No. 13-4, at p. 2). Four days later, plaintiff filed the instant action. (Doc. No. 1).

Plaintiff asserts five claims in its Complaint. At Count I, plaintiff advances a § 1983 claim, alleging that defendants, as state actors, violated its Fourteenth Amendment substantive due process and equal protection rights by denying its net metering applications and treating other customer-generators more favorably. (Id., at ¶¶ 46-73). At Count II, plaintiff seeks a declaratory judgment stating that customer-generators are not required to have a non-generational load in order to net meter under the Act. (Id., at ¶¶ 74-81).

Count III asserts a claim for "tortious interference with existing and potential contracts," on the ground that defendants' denials of plaintiff's applications have interfered with a contract guaranteed by the Act. (Id., at ¶¶ 82-93). Count IV purports to bring a direct cause of action under the Act premised on plaintiff having met all of the Act's requirements for net metering, and yet being excluded from doing so. (Id., at ¶¶ 94-102). Finally, plaintiff asserts a claim for unfair competition at Count V, contending that defendants "have engaged in conduct that is contrary to honest, industrial and commercial practices." (Id., at ¶¶ 103-07).

Defendants seek dismissal of plaintiff's claims on
7 a number of grounds. As to the federal *7 claim, they contend that all claims against PPL must be dismissed because no direct action by PPL has been alleged and liability cannot be predicated solely on *respondeat superior*. Plaintiff's § 1983 claim must be dismissed because neither defendant acted under color of state law and defendants are entitled to qualified immunity in any event. In the alternative, this court should abstain.

Moreover, defendants maintain that the court should decline to exercise supplemental jurisdiction over plaintiff's state law claims because all federal claims must be dismissed. Even assuming supplemental jurisdiction, each of plaintiff's state law claims fails. A declaratory judgment would be improper in light of the pending PUC proceeding. No reasonably probable contract with a third party can be alleged to support a claim for tortious interference. Finally, defendants maintain that plaintiff's remaining state law claims fail because (1) a private cause of action cannot be based on a violation of the Act and (2) Pennsylvania does not recognize the tort of unfair competition.

Plaintiff contends that defendants' conduct in enforcing a state regulatory scheme is state action, particularly where the power to do so has been delegated by the PUC. Defendants' qualified immunity defense fails in light of plaintiff's clearly established right to net meter under the Act. Further, abstention would be improper given the absence of (1) an unsettled question of state law and (2) "extraordinary circumstances."

Although conceding that the exercise of supplemental jurisdiction would be proper only if the federal claims are heard, plaintiff argues that each state law claim survives defendants' motion. Specifically, a declaratory judgment would be proper notwithstanding the pending PUC proceeding because this court has jurisdiction over closely intertwined claims. The tortious interference claim is supported by an "absolute certainty" of contractual relationships with third
8 *8 parties as well as with defendants. Further, as a customer-generator, plaintiff may maintain a claim for violation of the Act. Finally, while no Pennsylvania appellate court has recognized the tort of unfair competition, plaintiff asserts that the Pennsylvania Courts of Common Pleas have done so in similar circumstances.

Plaintiff cannot plead sufficient facts to maintain a § 1983 claim. In general, § 1983 does not itself create substantive rights, but instead provides a vehicle for vindicating a violation of a federal right.[3] Groman v. Township of Manalapan, 47 F.3d 628, 633 (3d Cir. 1995). A cause of action under § 1983 has two elements: a plaintiff must prove (1) a violation of a right, privilege or immunity secured by the constitution and laws of the United States (2) that was committed by a person acting under color of state law. Kneipp v. Tedder, 95 F.3d 1199, 1204 (3d Cir. 1996); Kelly v. Borough of Sayreville, 107 F.3d 1073, 1077 (3d Cir. 1997); Berg v. Cty. of Allegheny, 219 F.3d 261, 268 (3d Cir. 2000) ("The Plaintiff must demonstrate that a person acting under color of law deprived him of a federal right.") (citing Groman, 47 F.3d at 633).

[3] Section 1983 creates liability against " [e]very person who, under color of any statute, ordinance, regulation, custom, or

> usage, of any State or Territory or the District of Columbia, subjects, or causes to be subjected, any citizen of the United States or other person within the jurisdiction thereof to the deprivation of any rights, privileges, or immunities secured by the Constitution and laws." 42 U.S.C. § 1983.

In any § 1983 claim, "the first step is to identify the exact contours of the underlying right said to have been violated." County of Sacramento v. Lewis, 523 U.S. 833, 841 n.5 (1998) (citations omitted). Here, plaintiff alleges violations of its substantive due process and equal protection rights guaranteed by the Fourteenth Amendment. Defendants do not challenge plaintiff's invocation of these constitutional rights. Consequently, the court will assume that plaintiff's allegations set forth a plausible violation of these rights.

To satisfy the second element of its § 1983 claim,
9 plaintiff must show that defendants *9 acted under color of state law. See Kneipp, 95 F.3d at 1204. The Supreme Court has observed that the criteria for determining the presence of state action lacks rigid simplicity.[4] Brentwood Acad. v. Tennessee Secondary Sch. Athletic Ass'n, 531 U.S. 288, 296 (2001). Over the years the Court has established a number of approaches to answer the general question of whether there is a sufficiently "close nexus between the State and the challenged action [so] that seemingly private behavior may be fairly treated as that of the State itself." Id. (quoting Jackson v. Metropolitan Edison Co., 419 U.S. 345, 349 (1974)). It has identified a host of factors that can "bear on the fairness of such an attribution," such as when (1) the challenged activity results from the state's exercise of coercive power, (2) the state provides significant encouragement, either overt or covert or (3) a private party becomes a willful participant in joint activity. Id. (collecting cases in support).

4 The Court has explained that conduct which constitutes "state action" is also "action under color of state law and will support a suit under § 1983." Lugar v. Edmondson Oil Co., 457 U.S. 922, 935 (1982).

In Crissman v. Dover Downs Entertainment Inc., the United States Court of Appeals for the Third Circuit followed Brentwood's approach to evaluating allegations of state action by private parties. 289 F.3d 231, 239 (3d Cir. 2002). Regardless of whether the approach is treated as "tests" or "facts," "Brentwood directs courts to focus on the fact-intensive nature of the state action inquiry, mindful of its central purpose: to assure that constitutional standards are invoked 'when it can be said that the State is *responsible* for the specific conduct of which the plaintiff complains.'"[5] Id. (quoting Brentwood, 531 U.S. at
10 295 (quoting Blum v. Yaretsky, 457 U.S. *10 991, 1004 (1982) (emphasis in original)). In other words, the basic question is whether the challenged act can be "fairly attributed to the state." Crissman, 289 F.3d at 239 (citing American Mfrs. Mut. Ins. Co. v. Sullivan, 526 U.S. 40, 50 (1999)).

5 The Court pointed out in Lugar that it has never been clear "[w]hether these different tests are actually different in operation or simply different ways of characterizing the necessarily fact-bound inquiry that confronts the Court in [each] situation." 457 U.S. at 939; see also Groman, 47 F.3d at 639 n.16. Brentwood appears to embrace the second understanding. Crissman, 289 F.3d at 239 n.12.

Brentwood highlighted Lugar as an example of when private party conduct may be fairly attributed to the state under the theory of joint activity. Brentwood, 531 U.S. at 295. Lugar set forth a two-part approach to guide the fact-intensive inquiry in this area: "[f]irst, the deprivation must be caused by the exercise of some right or privilege created by the State or by a rule of conduct imposed by the State or by a person for whom the State is responsible" and "[s]econd the party charged with the deprivation must be a person who may fairly be said to be a state actor. This may be because he is a state official, because he has acted together with or has obtained significant aid from state officials, or because his conduct is otherwise chargeable to the State." Lugar, 457 U.S. at 937. Although these two principles are related, they are not the same. Id. They "collapse into each other when the claim of a constitutional deprivation is directed against a party whose official character is such as to lend the weight of the State to his decisions" and "diverge when the constitutional claim is directed against a party without such apparent authority, *i.e.* a private party." Id. (citing Monroe v. Pape, 365 U.S. 167, 172 (1961)).

Specifically with respect to private party conduct, the Court has found state action to be lacking at the first part of the analysis when the relevant offending decisions of a private party were unconnected with any governmental decision or regulation. Id. at 937-38 (discussing Moose Lodge No. 107 v. Irvis, 407 U.S. 163 (1972)). Even when private actions are purported to have been taken in accordance with a state statute, a finding of state action is precluded when the private party improperly invoked that statute. Id. at 940-41 ("private misuse of a state statute does not describe conduct that can be attributed to the State"). Once the analysis progresses to *11 part two, the Court has held that even "[a]ction by a private party pursuant to [a] statute, without something more, [i]s not sufficient to justify a characterization of that party as a 'state actor.'" Id. at 938-39 (discussing Flagg Brothers Inc. v. Brooks, 436 U.S. 149 (1978) (emphasis in original). The Luger Court then listed several ways in which the "something more" might be satisfied: the public function test, the state compulsion test, the nexus test and the joint action test. Id. at 939 (collecting cases).

Under Lugar, if alleged misconduct arises from a violation of a state statute or scheme that is valid, improper or unlawful invocation/utilization of the scheme is not enough to make the private party a state actor. Benn v. Universal Health System, Inc, 371 F.3d 165, 172 (3d Cir. 2004) (a private party's invocation of a statute without grounds to do so cannot "be attributed to a state rule or decision."). This principle extends to private parties that defectively or deficiently perform a prerequisite duty or obligation mandated by or under a state statute or scheme. Id. In contrast, allegations of joint participation in carrying out a state statute or scheme that is itself constitutionally defective states a claim for a due process deprivation. Lugar, 457 U.S. at 942; accord Cruz v. Donnelly, 727 F.2d 79, 82 (3d Cir. 1984) (where a state system requires a state official or body to act based solely on a private actor's judgment, "a private actor's mere invocation of state power renders that party's conduct actionable [as a joint actor with the state] under § 1983.").

A necessary characteristic to proceed under a joint participation approach is actual participation in the relevant conduct by state officials and the private party. See Fitzgerald v. Mountain Laurel Racing, Inc., 607 F.2d 589, 600 (3d Cir. 1979) ("only when the state officials with delegated authority to enforce state laws or regulations participate with management in the decisional process . . . is the requisite nexus under Jackson established."). Conspiratorial *12 conduct likewise can constitute joint action, satisfying the two-part analysis highlighted in Lugar. Lugar, 457 U.S. at 931 (quoting Adickes, 398 U.S. 144, 152 (1970) (a "private party's joint participation with a state official in a conspiracy to discriminate would constitute both 'state action essential to show a direct violation of petitioner's Fourteenth Amendment equal protection rights' and action 'under color of law for purposes of [§ 1983].'").

Under what the Luger Court referred to as the "state compulsion" test, id. at 939, state action by a private party can also be found "when the State, by its law, has compelled the act," Adickes, 398 U.S. at 170. "Under this approach, however, state action will be found only 'when the state has exercised coercive power or has provided such significant encouragement, either overt or covert, that the private decision must in law be deemed that of the State;' 'mere approval of or acquiescence in' the decision is not enough." McKeesport Hosp. v. Accreditation Council for Graduate Med. Educ., 24 F.3d 519, 525 (3d Cir. 1994) (quoting Blum, 457 U.S. at 1004). Thus, in order for a private actor's decision to be attributed to the state, the state must have in some way forced the particular result in question. See Blum, 457 U.S. at 1008 (finding no state action when decisions to discharge or transfer particular patients "ultimately turn[ed] on medical judgments made by private parties according to professional standards that [we]re not established by the State."); Jackson, 419 U.S. 345, 357 ("Approval by a state utility commission of . . . a request from a regulated utility, where the commission has not put its own weight on the side of the proposed practice by ordering it, does not transmute a practice initiated by the utility and approved by the commission into 'state action.'"); McKeesport Hosp., 24 F.3d at 525-26 (private accreditation body not a state actor when its decision to revoke a program's accreditation was based on private standards and state law recognized but did not dictate or influence the decision).

Finally, under the "public function" test, action
13 under color of state law may be found *13 when a private party "has been delegated . . . a power 'traditionally exclusively reserved to the State.'" McKeesport Hosp., 24 F.3d at 524 (quoting Flagg Brothers, 436 U.S. at 157). Recognition of private party state action under this doctrine has been confined to functions such as the conducting of elections or the performance of actual government functions. Flagg Brothers, 436 U.S. at 158-59.

Plaintiff's assertions that defendants acted under color of state law are wide of the mark. Their arguments are premised on defendants' exercise of the authority to consider and dispose of applications for net metering, which was delegated by the PUC. (Doc. No. 19, at pp. 9-19). Plaintiff contends that "[c]learly enforcement in this regard must be qualified as state action." (Id., at p 18). Defendants respond that "[t]his is not a 'delegation' of state authority; it is simply state regulation of private action." (Doc. No. 21, at p. 9). The court agrees with defendants.

In Jackson, the Court expressly acknowledged that "the supplying of utility service is not traditionally the exclusive prerogative of the State." Jackson, 419 U.S. at 353. Thus, a public utility must also exercise some separate power "traditionally associated with sovereignty, such as eminent domain," before it can be recognized as a state actor under the "public function" test. Id. The Third Circuit has drawn a distinction in this area. On one hand, it recognized that a delegation of state authority to "enforce" regulations "in the sense of actual policing or active governmental or official 'enforcement' of rules and regulations" can serve as such a basis for finding state action by the delegee. Crissman, 289 F.3d at 247. On the other, merely being tasked with "oversee[ing] compliance" with regulations is not traditional enforcement activity that will support such a finding. Id.

The authority delegated to EDCs by the PUC is not one "which is traditionally associated with sovereignty." Jackson, 419 U.S. at 353. Supplying
14 and/or terminating utility service is not *14 considered to be an exercise of sovereign authority. Id. It follows, *a fortiori*, that the subsidiary authority of a utility provider to determine whether applications to interconnect with its power grid comply with the established regulations does not meet this standard.

Moreover, nothing within the Regulations delegates to the EDCs a form of "enforcement" authority that could qualify as a "public function." See Crissman, 289 F.3d at 247. To the contrary, EDCs are merely tasked with overseeing a net metering application's compliance with the Regulations. Id. Given all of this, state action by defendants cannot be based on their ability to make erroneous decisions concerning net metering applications. See Benn, 371 F.3d at 172 ("private misuse of a state statute does not describe conduct that can be attributed to the State").

Likewise, the context of the parties' dispute precludes a reasonable inference of "joint participation" between defendants and the state. As discussed above, the inquiry into whether the challenged conduct can be fairly attributed to the state is a fact-intensive one. Crissman, 289 F.3d at 239 (citing American Mfrs. Mut. Ins. Co. v. Sullivan, 526 U.S. 40, 50 (1999)). Plaintiff acknowledges this inquiry, but fails to allege any facts in support of a joint effort between the PUC and PPLEU to deny plaintiff's applications. (Doc. No. 19, at p. 17). Instead, plaintiff explains in its brief that "[i]t is not yet clear, and will not be so without discovery, the extent to which the PUC was involved with PPL's decision." (Id., at p. 19). In its only other statement related to an inferred joint venture plaintiff surmises that "it would seem that PPL (and other EDCs for that matter) are actively working with the PUC to deny access to Sunrise utilizing net metering for its solar plants." (Id., at p. 8). In other words, plaintiff has alluded to nothing more than mere conjecture and cannot identify any fact which raises a reasonable inference that the PUC actually participated in evaluating plaintiff's applications (let alone directed PPLEU to reach a particular decision).

15 *15

These conclusory assertions that "the PUC was involved" and that PPL is "actively working with the PUC to deny access" stop short of alleging factual matter that plausibly shows the PUC jointly participated in PPLEU's decisions to deny plaintiff's applications. Of course, such "threadbare recitals . . . supported by mere conclusory statements, do not suffice." See Iqbal, 556 U.S. at 678.

It is *possible* that discovery could uncover some joint venture between defendants and the PUC. But under Twombly, this mere possibility is insufficient to make a showing of joint participation that is *plausible* on its face. Without sufficient factual matter to make a plausible showing that the PUC "participate[d] with [defendants] in the decisional process," plaintiff's claim cannot advance based on a theory of joint participation. See Fitzgerald, 607 F.2d at 600 ("We hold today that it is only when the state officials with delegated authority to enforce state laws or regulations participate with management in the decisional process . . . is the requisite nexus under Jackson established.").

Finally, state action by defendants cannot be based on the PUC having compelled the denial of plaintiff's applications through the Regulations. To be sure, when state law actually dictates or influences particular private decisions or when such decisions are made according to standards established by the state, state action may be found. McKeesport Hosp., 24 F.3d at 525 (citing Blum, 457 U.S. at 1008). But private decisions generally are not deemed to be the product of state action, even when the state approves or acquiesces in them. Id. (the exercise of coercive power or the provision of significant encouragement is necessary under the state compulsion approach; "'mere approval of or acquiescence in' the decision is not enough.") (quoting Blum, 457 U.S. at 1004).

Plaintiff's averments sufficiently undermine any
16 basis for proceeding under a compulsion *16
approach. It must be assumed that plaintiff's proposed facilities qualify as customer-generators, as nothing within the Act or the Regulations presently requires a customer-generator to have a non-generational load. (Doc. No. 19, at pp. 5, 19). However, the lack of a non-generational load is the very basis PPLEU identified for its decisions to first deny and then seek guidance regarding plaintiff's applications. (Doc. Nos. 1-5, 1-6, 1-7, 1-8). It is true that potential changes to the Regulations announced by the PUC would impose such a requirement. 44 Pa. Bull. 4179. But as plaintiff aptly notes, these changes have not even been officially proposed at this point, let alone taken legal effect. (Doc. No. 19, at p. 25).

Nowhere does plaintiff suggest that PPLEU's decisions were in any way compelled by the Regulations. In fact, plaintiff argues extensively that defendants' actions were "in violation of the Act" and the Regulations, (id., at p. 8), and specifically attempts to bring a separate cause of action under the Act for these actions, (id., at pp. 29-33). Such violations of a state statute or regulatory scheme cannot be the basis for state action by a private party. See Benn, 371 F.3d at 172 ("private misuse of a state statute does not describe conduct that can be attributed to the State"). And importantly, the occurrence of such violations clearly contradicts any contention that defendants' actions actually were compelled by the Regulations.

Based on the foregoing, plaintiff has failed to set forth a plausible showing of a sufficiently close nexus between the State and defendants' actions under any of the relevant approaches. See Brentwood Acad., 531 U.S. at 296. As such, the court cannot draw a reasonable inference that defendants' actions constituted state action. Dismissal of plaintiff's § 1983 claims therefore is proper.[6] Because plaintiff's § 1983 claims must be
17 dismissed, the court *17 will decline to exercise jurisdiction over the remaining state law claims pursuant to 28 U.S.C. § 1367(c)(3). See Stehney v. Perry, 101 F.3d 925, 939 (3d Cir. 1996) (district court properly may decline jurisdiction over pendant state law claims where federal claims have dropped from the case prior to trial, the parties will not be prejudiced by the dismissal of the state law claims, and the interests of judicial economy will be served); Queen City Pizza, Inc. v. Dominos' Pizza, Inc., 124 F.3d 430, 444 (3d Cir. 1997) (decision to dismiss state law claims where all federal claims have been dismissed "is committed to the sound discretion of the district court").[7]

6 Because the inability to make a plausible showing that defendants acted under color of state law provides an independently sufficient basis for dismissing plaintiff's § 1983 claims, the court need not decide whether defendants also are entitled to qualified immunity or abstention is appropriate.

7 Plaintiff's ability to pursue its state law claims will not be affected adversely as appropriate state forums are available to address each of plaintiff's concerns. First, plaintiff is actively participating in ongoing proceedings before the PUC to determine whether applicants like plaintiff are eligible to take part in net metering, having filed an Answer/New Matter/Counterclaim to PPLEU's petition. See PUC Docket No. P-2014-2420902. Should plaintiff be dissatisfied with the ultimate decision of the PUC in this matter, it will have the right as an aggrieved party to appeal to the Commonwealth Court of Pennsylvania. 2 Pa. Cons. Stat. § 702; 42 Pa. Cons. Stat. § 763. Second, a dispute process specifically regarding net metering applications is provided for in the Regulations. See 52 Pa. Code § 75.51. If plaintiff believes that its interests are not properly addressed by the existing PUC proceedings, it has the right as a "corporation having an interest in the subject matter" to separately "complain in writing, [to the PUC] setting forth any act or thing done or omitted to be done by any public utility in violation, or claimed violation, of any law which the commission has jurisdiction to administer, or of any regulation or order of the commission." 66 Pa. Cons. Stat. § 701. Again, plaintiff would have the option of appealing any adverse decision by the PUC to the Commonwealth Court. See 2 Pa. Cons. Stat. § 702; 42 Pa. Cons. Stat. § 763. Finally, should plaintiff wish to pursue its state law claims, a Pennsylvania Court of Common Pleas with appropriate venue would be available for that purpose. 42 Pa. Cons. Stat. § 931.

Moreover, plaintiff's state law claims will be dismissed without prejudice to plaintiff's ability to transfer those claims to the appropriate Court of Common Pleas as authorized by 42 Pa. Con. Stat. § 5103(b).

As previously indicated, plaintiff's § 1983 claim is subject to dismissal because (1) under some theories for state action plaintiff cannot as a matter of law show that defendants acted under color of state law and (2) as to other theories plaintiff has failed to plead sufficient factual matter under Twombly's plausibility standard to create a showing that defendants acted under color of state law. Under these later circumstances a plaintiff
18 generally is entitled to seek to cure *18 the deficiencies by amendment unless attempting to do so would be futile. Phillips, 515 F.3d at 236 (citing Grayson v. Mayview State Hospital, 293 F.3d 103, 108 (3d Cir. 2002)). But given the context and nature of the litigation there is no basis to assume or believe that plaintiff can cure the deficiencies highlighted above. Accordingly, the complaint will be dismissed and the Clerk of Court will be directed to mark the case closed. Nevertheless, in order to assure that any decision is not premature, the dismissal will be without prejudice to plaintiff filing a motion to re-open the case and amend its allegations pertaining to state action pursuant to factual averments that cure the deficiencies highlighted in this opinion.

For the reasons set forth above, defendants' motion to dismiss will be granted. An appropriate order will follow.

Date: March 27, 2015

s/David Stewart Cercone

David Stewart Cercone

United States District Judge
cc: Robert F. Daley, Esquire

D. Aaron Rihn, Esquire

A. Michael Gianantonio, Esquire

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Evaluation of Interoperable Distributed Energy Resources to IEEE 1547.1 Using SunSpec Modbus, IEEE 1815, and IEEE 2030.5

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ABSTRACT The American distributed energy resource (DER) interconnection standard, IEEE Std. 1547, was updated in 2018 to include standardized interoperability functionality. As state regulators begin ratifying these requirements, all DER—such as photovoltaic (PV) inverters, energy storage systems (ESSs), and synchronous generators—in those jurisdictions must include a standardized SunSpec Modbus, IEEE 2030.5, or IEEE 1815 (DNP3) communication interface. Utilities and authorized third parties will interact with these DER interfaces to read nameplate information, power measurements, and alarms as well as configure the DER settings and grid-support functionality. In 2020, the certification standard IEEE 1547.1 was revised with test procedures for evaluating the IEEE 1547-2018 interoperability requirements. In this work, we present an open-source framework to evaluate DER interoperability. To demonstrate this capability, we used four test devices: a SunSpec DER Simulator with a SunSpec Modbus interface, an EPRI-developed DER simulator with an IEEE 1815 interface, a Kitu Systems DER simulator with an IEEE 2030.5 interface, and an EPRI IEEE 2030.5-to-Modbus converter. By making this test platform openly available, DER vendors can validate their implementations, utilities can spot check communications to DER equipment, certification laboratories can conduct type testing, and research institutions can more easily research DER interoperability and cybersecurity. We indicate several limitations and ambiguities in the communication protocols, information models, and the IEEE 1547.1-2020 test protocol which were exposed in these evaluations in anticipation that the standards-development organizations will address these issues in the future.

INDEX TERMS Distributed energy resource, smart grid, interoperability, certification, IEEE std. 1547.1, communication, interconnection.

I. INTRODUCTION

Around the world, Distributed Energy Resource (DER) grid codes and interconnection standards have been evolving to include new grid-support functions. These standards often include functionality to provide voltage regulation (e.g., fixed power factor, voltage-reactive power, voltage-active power, and active power-reactive power functions), frequency response (frequency-active power or frequency-droop), and voltage and frequency ride-through capabilities [1]–[3]. Historically, these capabilities are enabled during the manufacturing or commissioning process and left to operate autonomously for the life of the equipment. While some standards have included ranges of adjustability for the functions–such as in California Rule 21 [4] and the Australian/New Zealand interconnection standard AS/NZS 4777 [5], [6]–the US interconnection standard, IEEE 1547-2018 [7], is the first to require DER equipment include ranges of adjustability and mandate DER devices include a standardized communication interface. This interface is designed to enable grid operators

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to read DER measurements and adjust settings and operating modes in near real-time.

Communications-enabled DER provide a wide range of benefits to grid operators. Transmission and distribution system operators have better visibility into distribution networks and can optimize DER settings according to schedules or real-time needs. There have been many studies that show the advantages of using DER Management Systems (DERMS) to configure the operations of fleets of DER devices. For example, carefully tuned voltage-reactive power (volt-var) curves or power factor set points can increase feeder hosting capacity [8] and support voltage on unbalanced feeders [9]. Communication-enabled DER also allow for new voltage regulation optimization techniques–e.g., Particle Swarm Optimization and Extremum Seeking Control–to be developed to set DER reactive power set points to minimize voltage deviations and circuit losses [10]. At the bulk system level, it is also possible to select frequency-watt parameters to provide fast frequency reserves [11], [12] and wide-area damping [13].

DER communications will also open up markets to provide third-party virtual power plants (VPPs) or aggregation services. In the United States, Federal Energy Regulatory Commission (FERC) Order 2222 [14] was passed in September 2020 which allows DER aggregations to participate in regional wholesale markets. In combination with DER interoperability functions, the FERC order will pave the way for VPP players in Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) wholesale markets in the U.S. There has been substantial research in different VPP approaches to use the DER active power and curtailment set points to provide transmission services. As an example, Castillo *et al.* designed a stochastic risk aversion-based rolling horizon optimization framework to bid into day-ahead scheduling and real-time dispatch markets [15]. Others investigated VPP optimization using chance-constrained methodologies [16], robust optimization [17], and stochastic programming [18] to meet load or generation needs.

In order to provide the aforementioned grid services, DER equipment must operate and communicate as expected. Unfortunately, it is challenging to verify DER equipment is functioning in accordance with grid codes and standards [19]–taking weeks if not months to perform all the experiments. In the last decade, evaluating DER equipment has been the source of significant academic interest and corporate investment. In the U.S. and Canada, DER equipment must be listed in accordance with regional requirements where it is installed. In most states, the requirements are harmonized to IEEE 1547-2003. The step-by-step test procedure for evaluating DER equipment to IEEE 1547 requirements is documented in IEEE 1547.1, but Nationally Recognized Testing Laboratories (NRTLs) certify DER compliance using Underwriters Laboratories (UL) 1741 [20]–which heavily references IEEE 1547.1 but provides greater testing detail in some key areas. UL 1741 was used to certify DER to IEEE 1547-2013; UL 1741 Supplement SA was added in 2016 to certify equipment to California Rule 21 and Hawaii Rule 14; and UL 1741 Supplement SB will certify DER to IEEE 1547-2018/IEEE 1547.1-2020. Since the development of UL 1741 Supplement SA added ranges of adjustment to the test procedure, it was no longer practical to manually certify equipment to the standards, and automated test beds started to emerge.

While there are proprietary test beds at NRTLs and DER vendor test facilities, the SunSpec Alliance and Sandia National Laboratories created an open-source, automated compliance testing software package called the System Validation Platform in 2014 [21], [22]. This software package has been further refined by an international network of research laboratories known as the Smart Grid International Research Facility Network (SIRFN), which operates under the International Smart Grid Action Network (ISGAN) International Energy Agency (IEA) Technology Collaboration Programme (TCP). This group has collaborated to write test logic to automate multiple test procedures. To date, some of the laboratory results include:

- *Compliance Protocol*: A pre-standardization Sandia-developed test procedure for IEC TR 61850-90-7 [23], [24]
  - connect/disconnect, active power curtailment, and power factor [25]
  - connect/disconnect, active power curtailment, power factor, reactive power-priority volt-var [26]
- *Compliance Protocol*: A SIRFN-developed test procedure for ESS devices [27]
  - active power, fixed power factor, volt-var, and frequency-watt [28]
- *Compliance Protocol*: UL 1741 SA
  - volt-var and specified power factor [29]
  - normal ramp rate, soft start ramp rate, specified power factor, volt-var, and frequency-watt [30]
- *Compliance Protocol*: IEEE 1547.1-2020
  - constant power factor, volt-var, frequency-droop, and volt-watt [31]
  - limit active power, constant reactive power, active power-reactive power (watt-var), and prioritization of grid-support functions [32]
  - voltage phase-angle change ride-though [33]
  - voltage ride-through, frequency ride-through, and rate of change of frequency (ROCOF) ride-through

These experiments were each executed by manually adjusting the DER settings through graphical user interfaces, proprietary Modbus interfaces, or 100-Series SunSpec Modbus Models–none of which were compliant to the IEEE 1547-2018 requirements. However, with the approval of IEEE 1547.1-2020, each of the IEEE 1547.1 compliance tests must now be conducted by adjusting the parameters with one of the IEEE 1547-mandated interfaces: SunSpec Modbus, IEEE 1815 (DNP3), or IEEE 2030.5. Each of the protocols have specific information models associated with the IEEE 1547 functionality, as shown in Table 1, which expose

DER nameplate, configuration, monitoring, and control mode information.

While some DER devices may include a DNP3 or IEEE 2030.5 interface natively, Modbus is currently the prevailing technology on the market. However, Modbus does not include any encryption or authentication,[1] so it is not intended to leave DER facility premises and will likely only communicate a very short distance to a IEEE 2030.5 or DNP3 gateway or converter–that may be a DER bolt-on module like that demonstrated in a California Solar Initiative project led by EPRI [35]. Using a converter, the DER will be able to connect to utility or aggregator systems through the public internet with standardized cybersecurity protections.

In this work, we validate the interoperability of multiple DER simulators using the information models in Table 1 in accordance with the IEEE 1547.1 compliance test protocol. This process exposed a number of errors, ambiguities, and issues with the test protocol, information models, and DER simulator implementations. These findings have been relayed back to the appropriate standards-making bodies and stakeholders. This paper represents the first detailed investigation of these information models using the DER interoperability certification procedure and is the first to demonstrate the IEEE 1547 communication protocols. The remainder of the paper is structured as follows: Section 2 describes the methodology used to conduct the experiments; Section 3 provides detailed results of the experiments; Section 4 summarizes the standards development recommendations; and Section 5 concludes the paper with the major findings from this work.

TABLE 1. Information models associated with each of the IEEE 1547 communication protocols.

Protocol	Information Model for IEEE 1547 Functionality
Modbus	700-Series SunSpec Modbus Model Definitions [36]
IEEE 1815	DNP3 Application Note [37]
IEEE 2030.5	Common Smart Inverter Profile (CSIP) [38]

II. EXPERIMENTAL APPROACH

The SVP was designed as a highly versatile platform for automating certification experiments. Now, more than eight years in development, it includes a wide range of abstraction layers and equipment drivers. The abstraction layers are used to expose different classes of drivers in the GUI so the same testing logic (scripts) can be used to run experiments at different laboratories by only changing the test parameters in the script [22], [39]. Current abstraction layers included in the SVP Energy Lab repository [40] are AC/grid simulators, DC/PV simulators, DER, battery simulators, data acquisition systems, and gensets, switches, and loads. Using this software, Sandia created an IEEE 1547.1 interoperability certification script [41] that automates the evaluation of DER communications for nameplate, configuration, and setting information. This script also provided a means to spot-check the communications required to run all the electrical tests that can be configured via the communication port.

Executing a full IEEE 1574.1 interoperability compliance test for a given communication protocol is challenging because it requires verification of the entire information model. The test procedure is shown in Table 2. To certify a device to any of the protocols, in addition to verifying the measurement points by adjusting the grid simulator settings or DER operating modes, the DER must be evaluated for the management functions (volt-reactive power, freq-droop, etc.) using the specified communication protocol. The pass/fail criteria for those tests is the same as the management function tests which evaluate the electrical characteristics of the DER. In order to accelerate and automate IEEE 1547.1 testing, the SVP was updated to include drivers for SunSpec Modbus via pySunSpec2 [42], IEEE 1815, and IEEE 2030.5. To conduct the nameplate, configuration, and monitoring information tests, a *IOP.py* SVP script was created. Additional IEEE 1547.1 SVP scripts were also created to evaluate the interoperability and electrical functionality of the management functions, as shown in the final column of Table 3.

Sandia, SunSpec, EPRI, Kitu Systems, and SIRFN labs collaborated to create the testing scripts and DER simulators required to evaluate the conformance tests and information models. The SVP test environment used for these evaluations is shown in Figure 1. The SVP was connected to four DER end-point simulators which each used an IEEE 1547-mandated protocol:

- *SunSpec DER*: A SunSpec-constructed DER emulator that ingests a JSON file to create a SunSpec-compliant device with all of the 700-Series Models. This device did not include a power system or power electronics simulation capability–only a state-based representation of a SunSpec-compliant DER device. The SVP interacted with this DER simulator using the pySunSpec2 python package.
- *IEEE 1815 DER*: The EPRI DER Simulator version 1.0.6 with a DNP3 interface included a partial implementation of the DNP3 Application Note (App Note) AN2018-001. This simulator is a windows executable with the ability to run the power electronics simulation with irradiance, grid voltage, and grid frequency temporal profiles loaded from CSV files [43]. To communicate DNP3 commands to the EPRI simulator, a windows-based DNP3 Master agent was instantiated by the SVP. The DNP3 agent included a TCP server and associated backend API which would configure interactions with DNP3 outstations. The SVP sent HTTP JSON client requests to the DNP3 Master agent server to get Analog Input (AI) or Binary Input (BI) values from the EPRI DER Simulator outstation, or write Analog Output (AO) or Binary Output (BO) values to the outstation.
- *IEEE 2030.5 DER #1*: The Kitu Systems IEEE 2030.5 client with DER simulation capabilities. This client was built on a Raspberry Pi single board computer

[1] MODBUS/TCP Security does provide these security capabilities but is not commonly used. See [34] for more details.

TABLE 2. Nameplate Data, Configuration information, and Monitoring information interoperability tests required in IEEE 1547.1 for each protocol.

Test	SunSpec Modbus	IEEE 2030.5	IEEE 1815	SVP Script
Nameplate Data Test	Read/verify data in 1547.1 Table 45	Read/verify data in 1547.1 Table 57	Read/verify data in Nameplate Information (Energy/RMS/ Other) in DNP3 App Note Table 63	IOP.py
Configuration Information Test	Write data in 1547.1 Table 45	Write data in 1547.1 Table 57	Write data in Nameplate Information (Energy/RMS/Other) in DNP3 App Note Table 63	IOP.py
Monitoring Information Test	Read/verify data in 1547.1 Table 46	Read/verify data in 1547.1 Table 58	Read/verify data in 1547.1 Table 58	IOP.py

TABLE 3. Management information interoperability tests required in IEEE 1547.1 for each protocol. The "electrical tests" mandated in IEEE 1547.1 which are evaluated using the standardized communication interface.

Test	SunSpec Modbus	IEEE 2030.5	IEEE 1815	SVP Script
Constant Power Factor (CPF) Mode Test	Run 1547.1 CPF Test using Table 47	Run 1547.1 CPF Test using Table 59	Run 1547.1 CPF Test per DNP3 App Note 2.7.2.	CPF.py
Voltage-Reactive Power (VV) Mode Test	Run 1547.1 VV Test using 1547.1 Table 48	Run 1547.1 VV Test using 1547.1 Table 60	Run 1547.1 VV Test per DNP3 App Note 2.7.3.	VV.py
Active Power-Reactive Power (WV) Mode Test	Run 1547.1 WV Test using 1547.1 Table 49	Run 1547.1 WV Test using 1547.1 Table 61	Run 1547.1 WV Test per DNP3 App Note 2.7.4.	WV.py
Constant Reactive Power (CRP) Mode Test	Run 1547.1 CRP Test using 1547.1 Table 50	Run 1547.1 CRP Test using 1547.1 Table 62	Run 1547.1 CRP Test per DNP3 App Note 2.7.1.	CRP.py
Voltage-Active Power (VW) Mode Test	Run 1547.1 VW Test using 1547.1 Table 51	Run 1547.1 VW Test using 1547.1 Table 63	Run 1547.1 VW Test per DNP3 App Note 2.6.7.	VW.py
Voltage Trip (VT) Test	Run 1547.1 VT Test using 1547.1 Table 52	Run 1547.1 VT Test using 1547.1 Table 64	Run 1547.1 VT Test per DNP3 App Note 2.5.1.	VRT.py
Frequency Trip (FT) Test	Run 1547.1 FT Test using 1547.1 Table 53	Run 1547.1 FT Test using Table 65	Run 1547.1 FT Test per DNP3 App Note 2.5.2.	FRT.py
Frequency Droop (FW) Test	Run 1547.1 FW Test using 1547.1 Table 54	Run 1547.1 FW Test using 1547.1 Table 66	Run 1547.1 FW Test per DNP3 App Note 2.5.3.	FW.py
Enter Service (ES) and Cease to Energize and Trip Tests	Run 1547.1 ES Test using 1547.1 Table 55	Run 1547.1 ES Test using 1547.1 Table 67	Run 1547.1 ES Test per DNP3 App Note 2.4.5.	TBD
Limit Maximum Active Power (LAP) Test	Run 1547.1 LAP Test using 1547.1 Table 56	Run 1547.1 LAP Test using 1547.1 Table 68	Run 1547.1 LAP Test per DNP3 App Note 2.6.1.	LAP.py

with an IEEE 2030.5 CSIP information model with an optional DER simulator. The private keys for the Kitu Client were used to communicate to the device using an IEEE 2030.5 server developed by SunSpec. This server configured default settings (as opposed to scheduled behaviors) and was a standalone application from which the Kitu client retrieved information at fixed poll rates.

- *IEEE 2030.5 DER #2*: A IEEE 2030.5-to-Modbus converter developed by EPRI that interfaced with the EPRI DER Simulator. This converter ran as an executable on Ubuntu 20.04.2 LTS with a configurable poll rates. The converter was also configured to connect to the SunSpec IEEE 2030.5 server as shown in Figure 1.

In the case of the IEEE 2030.5 experiments, the SunSpec server was used because it allowed the greatest flexibility and visibility in debugging and viewing client-server errors and messages. A range of other client-server topologies could have been investigated–and should be in the future to ensure true interoperability. For instance, the Kitu Client and EPRI converter could also connect to a Kitu IEEE 2030.5 Server, the IEEE 2030.5 Test Tools from QualityLogic, or other commercial IEEE 2030.5 servers. To perform the interoperability experiments with that equipment, the SVP would need the ability to update server configurations and retrieve client data from the Kitu Systems NorthGate Server API or QualityLogic test environment.

An added complication with IEEE 2030.5 testing was provisioning the SVP with the client certificate and private key to establish the Transport Layer Security Version 1.2 (TLS 1.2) session with the server. The Common Smart Inverter Profile (CSIP) defines a specific cipher suite (TLS_ECDHE_ECDSA_WITH_AES_128_CCM_8) to perform asymmetric encryption of IEEE 2030.5 exchanges [44]. In order to establish the connection and interact within the Public Key Infrastructure (PKI) ecosystem,[2] the IEEE 2030.5 server was configured with the server certificate, server private key, and root certificate in Privacy Enhanced Mail (PEM) files. The server made the TLS connection with OpenSSL to the Kitu and EPRI clients using those PEM files, the certificate and private key of the client, and the cipher specifications.

It should also be noted that the IEEE 1547.1 testing is not a comprehensive interoperability test sequence. It is designed to verify a basic level of functionality to demonstrate the DER communication interface is connected appropriately to the electrical control and measurement capabilities of the DER. In order to fully validate the communication capabilities of DER, a separate certification program has been established by the SunSpec Alliance for IEEE 2030.5 clients and servers,

[2]The SunSpec Test PKI certificates were used for all the tests. Details on the certificates are provided in [45].

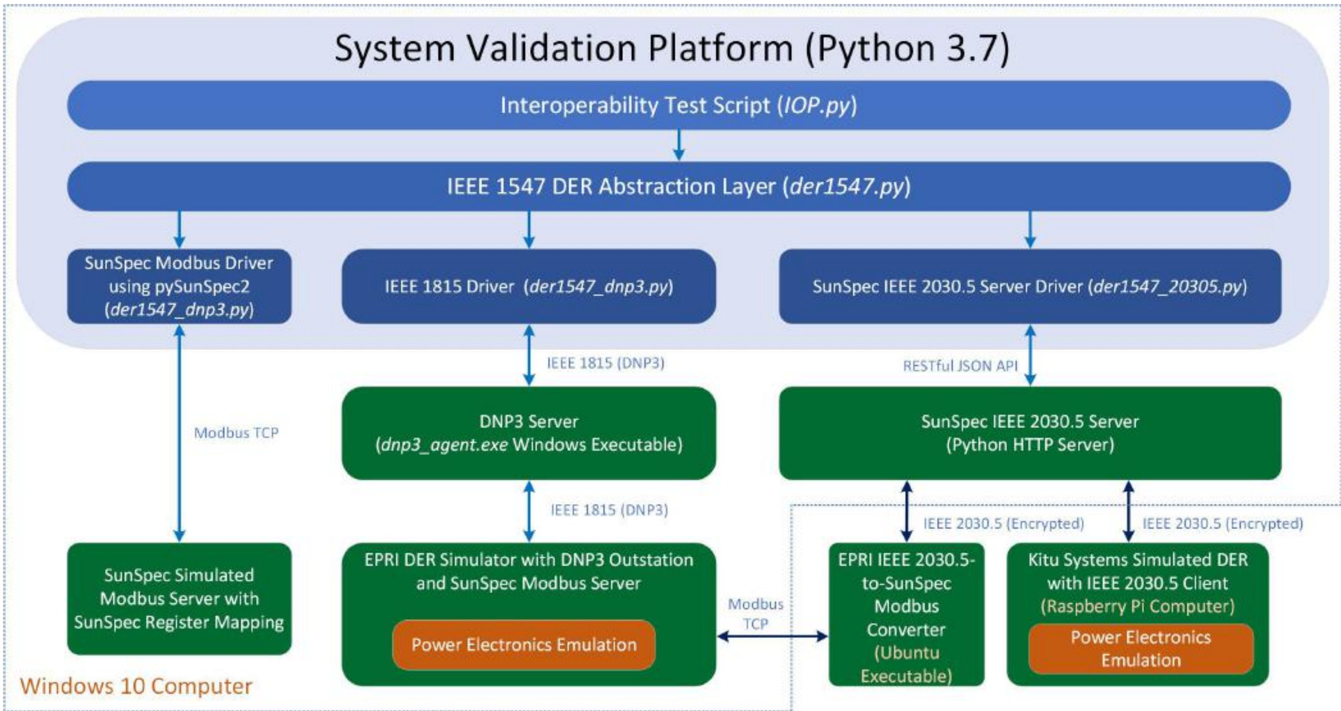

FIGURE 1. SVP connections to the DER simulation equipment.

SunSpec Modbus devices, and IEEE 1815 masters and outstations [46]. In the program, vendors submit their products to one of the SunSpec Authorized Test Labs (ATLs) for compliance certification. Those labs verify the full communication functionality of the devices and send the trace files to SunSpec for final certification validation. For instance, in the case of the Modbus devices, this process verifies that single registers can be read/written, multiple adjacent holding registers can be read/written using a single request, and multiple non-adjacent holding registers can be read/written in multiple requests [47]; and in the case of IEEE 2030.5, the program verifies the security features (e.g., appropriate cipher suites, certificate encoding, establishing valid TLS 1.2 connections, etc.), uses the HTTP protocol, checks the function sets (time, event handling, event priorities, etc.), and verifies that all the IEEE 1547-mandated functions can be acquired from the server and are implemented in the client [48]. These experiments are not included in the IEEE 1547.1 test procedure.

III. RESULTS

Working with these prototype DER devices, the first hands-on assessment of the IEEE 1547.1 interoperability tests were conducted. Unfortunately, not all the functionality was included in these devices (e.g., statuses, alarms, operational states, etc. we're not present in the EPRI simulator), so not all the functionality was evaluated for each of the protocols/DER simulators. To execute the experiments, a DER 1547 abstraction layer was created and read and write methods were built for the drivers for IEEE 2030.5 (der1547_20305.py), IEEE 1815 (der1547_dnp3.py), and SunSpec Modbus (der1547_sunspec.py). The following section presents the results from the experiments. Errors and ambiguities in the test and communication protocols were identified for feedback to the standards working groups.

Each of the DER simulators and associated communication tools were instantiated at the beginning of the IEEE 1547 interoperability tests. In the case of the SunSpec Modbus, a JSON mapping of a SunSpec Modbus device was imported by the pySunSpec2 Python package and this SunSpec object was used for all the interactions. This object did not include a power electronics model so the measurements were static values included in the JSON data file.

For the IEEE 1815 experiments, the SVP used an operating system bash shell command to start the DNP3 Agent with variables to indicate the Agent IP address and Outstation IP address (both use the 127.0.0.1 loopback address since the SVP, DNP3 Agent, and EPRI DER Simulator are all on the same Windows 10 machine), the Agent and Outstation IP port, Outstation local address, Master local address, and request ID. The EPRI Simulator was also started with a system command from Python and pywinauto was used to interface with the GUI. The DER nameplate capacity information was preloaded as a CSV in the Windows GUI. At start up, the SVP enabled the DERMS mode in the EPRI Simulator and the DNP3 Agent connected to the outstation and read the AI and BI points in the device. Then, the SVP commenced the IEEE 1547.1 test sequence with the EPRI Simulator outstation using the DNP3 Agent API to issue read/write commands to the device.

For the IEEE 2030.5 testing, the IEEE 2030.5 Server was started on port 9443 for the Kitu experiments and port 8443 for the EPRI converter experiments. The clients were then initialized and communicated to the server by getting */sep2/dcap*, creating a resource tree with *dcap*, *tm*, *der*, *edev*, *fsa*, *derp*, *dc*, *derc*, *dderc*, *rsp*, *upt*, and *mup* paths for the given Short Form Device Identifier (SFDI). The SVP communicated to the SunSpec server API via an HTTP API on the loopback IP address. Initially, there were challenges communicating with the EPRI converter because the server was closing the HTTP connection between messages and the client expected the connection to remain open for the duration of the experiments. Since a TCP connection can be closed for many reasons outside of the control of the endpoints, it is important to ensure communication failures are recoverable. This highlights some of the interoperability challenges that exist when testing with a single client or server–there will be different use cases that are not represented by the IEEE 1547.1 requirements.

A. NAMEPLATE DATA TEST

The nameplate data provides information about the DER device. The IEEE 1547.1 test procedure requires the tester to read the values for each of the nameplate data points and compare them against the manufacturer-provided values.

1) SunSpec MODBUS

The nameplate data is included in SunSpec *Common* Model 1 and *DERCapacity* Model 702, as shown in Table 4. In the case of the simulated SunSpec-compliant DER, the IEEE 1547-mandated points were read as anticipated. Notably, there are additional nameplate data points included in SunSpec Model 702, added based on the needs of the stakeholders in the SunSpec Alliance Modbus Working Group, but these were not required for IEEE 1547 certification.

2) IEEE 1815

With the exception of Manufacturer, Model, Serial Number, and Version Data, the DNP3 App Note includes AI and BI points for all the Nameplate data points as shown in Table 4 and aligned with IEEE 1547.1 and App Note Table 63. Manufacturer, Model, Serial Number, and Version Data are optional Device Attribute Objects in point number 0 of object group 0. So in practice, the master can read *Device Attributes – Device serial number* at Group 0 Variation 248, *Device Attributes – Device manufacturer's product name and model* at Group 0 Variation 250, and *Device Attributes – Device manufacturer's name* at Group 0 Variation 248 with point index 0, though the EPRI Simulator did not include this functionality. In fact, the DNP3 App Note requires only a DNP3 Level 2 (DNP3-L2) device so some DERMS masters many not have the ability to read this class object data. Therefore, it is recommended to move these values to AI points in the DNP3 Application Note.

Not all the other data points were included in the EPRI DER Simulator either, e.g., *Active power rating at specified over-excited power factor*, *Abnormal operating performance category*, and some of the *Supported control mode functions* returned null, but the DNP3 driver and DNP3 Agent successfully returned numeral and string data and reporting null data points to the user, demonstrating the ability of the SVP and DNP3 Agent to complete the IEEE 1547.1 Nameplate Data Test.

3) IEEE 2030.5

The Kitu Client was configured with a 600-second poll rate and the EPRI converter with a 60-second poll rate, after which they retrieved the control resources associated with the client from the server. The SVP configured the topological and DER resources in the server using the SunSpec backend API in order to establish the client-server connection and program IEEE 2030.5 settings. The information pushed to the server was nameplate information, monitoring data, and status/alarm information. This information was stored in the server and pulled into the SVP via the API. Each class of resources includes a poll rate, so the monitoring data could be updated at a quicker rate than status information, for example. The DER nameplate information is POSTed to the server a single time after GETting down the end device resource locations from the server. The SVP gets the *DERList* link based on the SFDI and Long Form Device Identifier (LFDI), finds the *DeviceInformation* and *DERCapability* links, and then reads the nameplate points. The *DERCapability* Link and Resource are shown in Fig. 7 with the *DERSettings* and *DERStatus* points.

The paradigm for testing a IEEE 2030.5 client is much different than Modbus and DNP3 because the SVP is not directly reading or writing data on the DER. The SVP is configuring the server and then waiting for the client to interact with it. As a result, there are much longer test times because the SVP must wait (up to the resource poll rate) for the client to exchange data with the server.

B. CONFIGURATION DATA TEST

For the configuration information tests in IEEE 1547.1 the following parameters are read and the DER behavior is measured through a data acquisition system:

- Active power rating at unity power factor (nameplate active power rating)
- Apparent power maximum rating
- Reactive power injected maximum rating
- Reactive power absorbed maximum rating
- For ESS, active power charge maximum rating
- For ESS, apparent power charge maximum rating

These parameters are set to 80% of the initial value, re-verified with the data acquisition system, and returned to 100% of the initial value to be verified a final time. The pass/fail indicates that the values should match the configuration data. Adding an allowable tolerance on the accuracy of these points would be useful in the future. The *Supported control mode functions* are also verified to operate as expected

TABLE 4. Nameplate data and communication points for the IEEE 1547-mandated protocols.

Nameplate Data	DNP3	IEEE 2030.5	SunSpec Modbus
Active power rating at unity power factor (nameplate active power rating)	AI4	DERCapability:: rtgMaxW	702.WMaxRtg
Active power rating at specified over-excited power factor	AI6-AI7	DERCapability:: rtgOverExcitedW	702.WOvrExtRtg
Specified over-excited power factor	AI8	DERCapability:: rtgOverExcitedPF	702.WOvrExtRtgPF
Active power rating at specified under-excited power factor	AI9-AI10	DERCapability:: rtgUnderExcitedW	702.WUndExtRtg
Specified under-excited power factor	AI11	DERCapability:: rtgUnderExcitedPF	702.WUndExtRtgPF
Apparent power maximum rating	AI14	DERCapability:: rtgMaxVA	702.VAMaxRtg
Normal operating performance category	AI22	DERCapability:: rtgNormalCategory	702.NorOpCatRtg
Abnormal operating performance category	AI23	DERCapability:: rtgAbnormalCategory	702.AbnOpCatRtg
Reactive power injected maximum rating	AI12	DERCapability:: rtgMaxVar	702.VarMaxInjRtg
Reactive power absorbed maximum rating	AI13	DERCapability:: rtgMaxVarNeg	702.VarMaxAbsRtg
Active power charge maximum rating	AI5	DERCapability:: rtgMaxChargeRateW	702.WChaRteMaxRtg
Apparent power charge maximum rating	AI15	DERCapability:: rtgMaxChargeRateVA	702.VAChaRteMaxRtg
AC voltage nominal rating	AI29-AI30	DERCapability:: rtgVNom	702.VNomRtg
AC voltage maximum rating	AI3	DERCapability:: rtgMaxV	702.VMaxRtg
AC voltage minimum rating	AI2	DERCapability:: rtgMinV	702.VMinRtg
Supported control mode functions	BI31-BI51	DERCapability:: modesSupported	702.CtrlModes
Reactive susceptance that remains connected to the Area EPS in the cease to energize and trip state	AI21	DERCapability:: rtgReactiveSusceptance	702.ReactSusceptRtg
Manufacturer		DeviceInformation:: mfID	1.Mn
Model		DeviceInformation:: mfModel	1.Md
Serial number		DeviceInformation:: mfSerNum	1.SN
Version		DeviceInformation:: mfHwVer, DeviceInformation:: swVer	1.Vr

when enabling and disabling each of the management (grid-support) functions; although no specifics are provided on how to do this, leaving it to the interpretation of the test engineer on how to perform the experiment. Adding more detail in IEEE 1547.1 to that test case would be helpful to ensure all the experiments are conducted in the same manner.

In IEEE 1547.1, the SunSpec, DNP3, and IEEE 2030.5-specific tests state that the nameplate points are to be overwritten for the configuration information data tests. This is a poor practice, and SunSpec Modbus and IEEE 2030.5 have created settings points so that the nameplate data is never overwritten. There are also typos in IEEE 1547.1 mislabeling IEEE 2030.5 nameplate and configuration information test section titles (Sections 6.8.2.1 and 6.8.2.2), which should be cleaned up in the next revision.

1) SunSpec MODBUS

Using pySunSpec2 to interact with the setting points in the DERCapacity Model produced the intended changes in the SunSpec Models. Since this DER simulator did not include a power simulation, there was no way to independently verify the DER operations were changed with these updates. In the future, this will need to be verified for DER devices when undergoing IEEE 1547.1 tests.

2) IEEE 1815

As stated above, the IEEE 1547.1 standard states the tests should use the same data points for configuration information as the nameplate data points. In the case of DNP3, this is not possible because nameplate data are AI and BI points, as indicated in Table 63 of the DNP3 Application Note. As a result, there are no DNP3 outputs (DER inputs) that permit changing the nameplate information. The DNP3 App Note and IEEE 1547.1 should be updated with AO and BO points to adjust the nameplate values. Or, preferably, there should be a completely new set of AO/BO and AI/BI points that represent the device settings–similar to the approach used in SunSpec Modbus and IEEE 2030.5. This way the nameplate DNP3 information can never be changed. This is a significant gap in the DNP3 information model that will need to be updated to allow DER devices to be tested to the IEEE 1547.1 requirements.

3) IEEE 2030.5

While IEEE 1547.1 states that the DERCapability Resource should be used to make configuration data changes on the client-side and IEEE 2030.5 Appendix A states that HTTP GET/HEAD and PUT are mandatory for DERCapability, it is preferred to use DERSettings to update the configuration parameters in the client. As shown in Figure 7, *DERSettings* includes *setMaxW*, *setMaxVA*, *setMaxVar*, *setMaxVarNeg*, *setMinPFOverExcited*, *setMinPFUnderExcited*, *setMaxChargeRateW*, *setMaxChargeRateVA*, and *modesEnabled* which allows the SVP to communicate the configuration changes to the client/DER via the server. An example XML exchange to make this update from the server is shown at the bottom of Fig. 2.

Generally, the client will PUT their *DERCapability* and *DERSettings* to the server to inform the server of the DER nameplate ratings and settings. *DERCapability* and

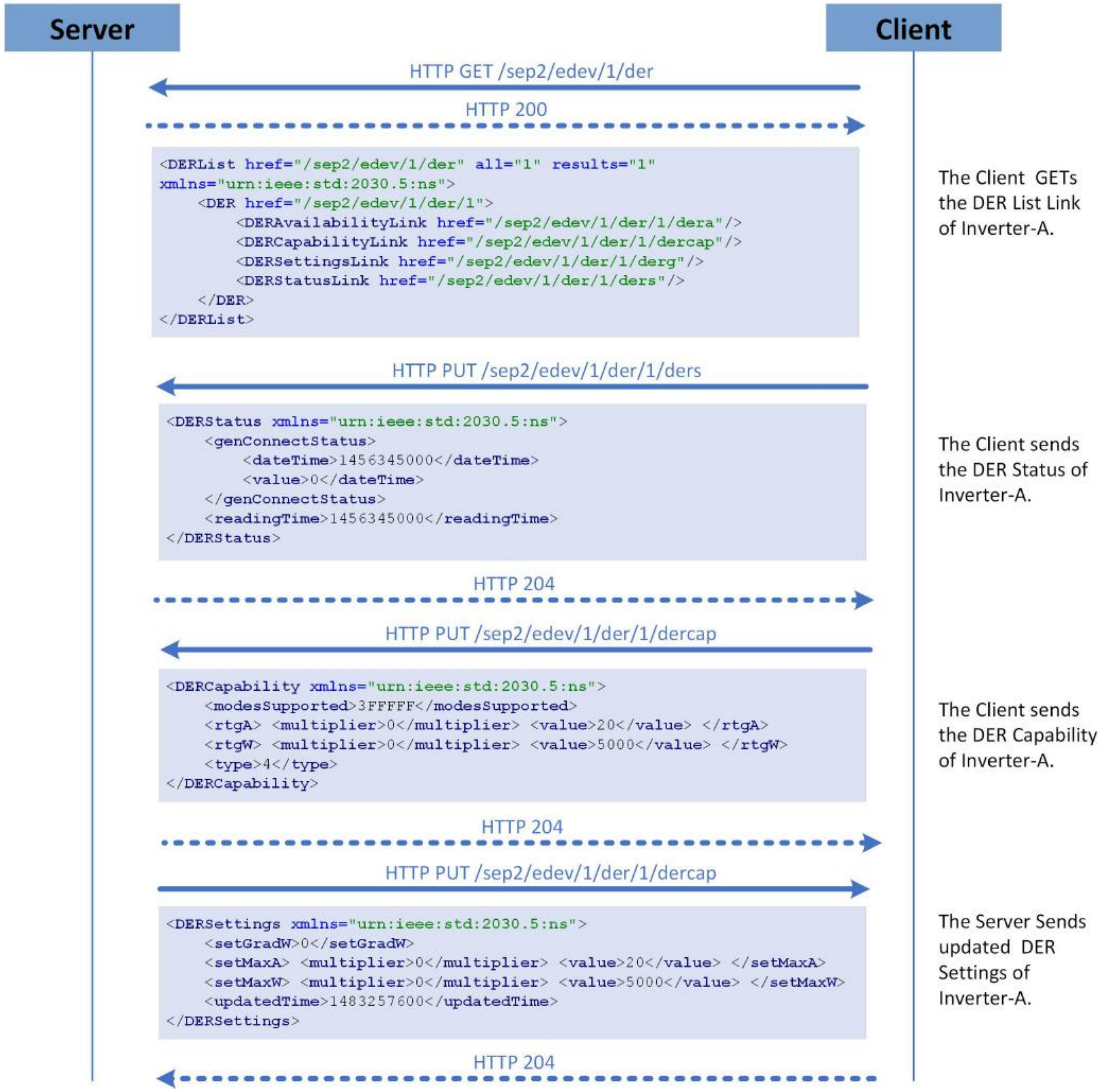

FIGURE 2. **The client-server interaction to gather nameplate information and to update the client settings.**

DERSettings are not meant for the server to make changes to these values on the client. Instead, in the case of the Kitu system, there was a subset of client "settings" that a server can change on the client. These changeable settings are mapped to a *DefaultDERControl* (e.g. *setGradW*, *setSoftGradW*, and Enter Service settings). If the server sets any of these *DefaultDERControls*, the client will change its *DERSettings* and put the new values to the server. During the tests, the server *DERSettings* configuration was updated with the new *DERSettings* data and read back using the API; however, it was much more difficult to evaluate if the client picked up these settings or taken affect. The IEEE 1547.1 test requires that the test lab verify "the value reported matches the behavior of the DER measured through independent test equipment separate from the DER interface". To do this, the SVP is designed to adjust the settings, wait for the poll rate, read back the setting in the server and then independently check the power measurement using a data acquisition system. It is not clear how to verify supported modes, other than to run electrical tests which would indicate their operation when enabled and disabled–a time intensive and difficult task that is not defined in IEEE 1547.1.

C. MONITORING INFORMATION TEST

The IEEE 1547.1 monitoring information tests are designed to verify the DER can measure and report grid conditions, internal states, and alarm statuses. The tests set the DER to two operating points shown in Table 6, measured the value after at least 30 seconds, and verify the reported values match the operation conditions. The pass/fail criteria in 6 states the values should be within the allowable accuracies for each of the measurements in IEEE 1547 Table 3. The test procedure does not indicate how to produce the operating points, so it may be helpful for the IEEE committee to clarify this in the future. For instance, if testing a PV inverter, it would be possible to produce the active power setpoints be either changing the DC input to the EUT or commanding the DER to an active power curtailment mode. While it may be beneficial to use external sources to produce these operating points as to not rely on DER controls to validate the monitoring information, to produce the reactive power setpoints, a reactive power mode will need to be used. Oddly, in the general IEEE 1547.1 interoperability testing section for monitoring (Section 6.6.2) does not include the Operational State of Charge (SoC) that is in the protocol-specific requirements in Sections 6.8.1.3, 6.8.2.3, and the DNP3 App Note Table 63, shown in the monitoring data points in Table 5.

There is poor alignment between the information models in terms of data points or naming conventions for DER states and alarms. The reported data required for the Operational State test is an on/off indication; the connection status data must report a connected/disconnected state, and only a single alarm is required for the Alarm Status. There is no direct mapping between the information models shown in the comparison of SunSpec Modbus 701.Alrm, the DNP3 App Note Alarms in BI0-BI9, and the IEEE 2030.5 CSIP alarms from the bit-mapped resource, DERStatus:alarmStatus, as shown in Table 7. As a result, it is very difficult to create a communication protocol agnostic test for the alarms. Currently, the grid voltage in the IOP test is set to $1.25 * V_{nom}$ which will cause a high voltage alarm for SunSpec and IEEE 2030.5 devices, but it is not clear what, if any, alarms will be raised on a DNP3 device. Poor harmonization between the information models also makes creating an EUT abstraction layer difficult because all alarm names have to be supported. Non-harmonization issues like this are also present with many other parameters. For instance, the Operational State and Connection Status in the SunSpec Modbus Models are binary, IEEE 2030.5 CSIP Connection Status options include *Connected*, *Available*, *Operating*, *Test*, and *Fault/Error* and Operational State options are *Not applicable/Unknown*, *Off*, *Operational mode*, and *Test mode*, whereas the DNP3 App Note contains 15 Connection Status/Operational State points. For testing purposes, these status/state options were converted to a binary value to autonomously issue pass or fail results for the monitoring tests.

1) SunSpec MODBUS

The SunSpec Modbus simulator did not include a power electronics simulation, inter-register logic/state machine, or have the ability to measure a power system, but these experiments were conducted to demonstrate the test sequence. To test active power measurements, the Limit Active Power (LAP) function was used to create the two test conditions. Constant Reactive Power (CRP) was used to test the two reactive power monitoring points–although the SVP test script does offer the option to test with Constant Power Factor (CPF). In creating the test script, it was discovered the Injected/Absorbed indications in *Reactive Power (Injected)* and *Reactive Power (Absorbed)* operating points were ambiguous and could indicate the active power direction or the excitation of the reactive power. It was assumed to be the latter. The voltage, frequency, operation state, connection status, and alarm status were measured and manually verified to reflect the state of the DER simulator.

2) IEEE 1815

The DNP3 interface on the EPRI DER Simulator demonstrated the ability to monitor active power, reactive power, voltage, frequency, and connection status. The active power was verified using LAP; reactive power was inspected using CPF; and the connection status checked with a connect/disconnect command written to BO5. The DNP3 voltage and frequency monitoring points were confirmed by manually adjusting the voltage and frequency sliders on the DER Simulator GUI. The operational state and alarms were not implemented in the DER Simulator, so those DNP3 points and associated call in the DNP3 driver could not be validated.

3) IEEE 2030.5

Using the *MirrorMeterReading* XML schema in Fig. 3, the IEEE 1547.1 measurements points were transferred to the IEEE 2030.5 server. This action was completed at the meter post rate defined in the client. This occurred at 300 second update rates for the Kitu client and 60 seconds for the EPRI client. The SVP queried the server every second until the server was updated to a monitoring information value within the permitted range. This process took much longer than the DNP3 and SunSpec Modbus tests because of the added time waiting for the client to send a measurement update.

D. MANAGEMENT INFORMATION TESTS

The management information tests cover the management functions included in Table 3: constant power factor, voltage-reactive power, active power-reactive power, constant reactive power, voltage-active power, voltage trip, frequency trip, frequency droop, enter service and cease to energize and trip, limit maximum active power. These are the functions that include adjustable settings in IEEE 1547-2018. To test them, the test sequences from the electrical type tests were repeated using the standardized interface to communicate the settings to the EUT. Originally, there was no mechanism

TABLE 5. Monitoring points for the IEEE 1547-mandated protocols.

Monitoring Data	DNP3	IEEE 2030.5	SunSpec Modbus
Active Power	AI537	ReadingType::accumulationBehaviour = 12 ReadingType::commodity = 1 ReadingType::flowDirection = 19 ReadingType::kind = 37 ReadingType::uom = 38	701.W
Reactive Power	AI541	ReadingType::accumulationBehaviour = 12 ReadingType::commodity = 1 ReadingType::flowDirection = 19 ReadingType::kind = 37 ReadingType::uom = 63	701.Var
Voltage	AI547-AI553	ReadingType::accumulationBehaviour = 12 ReadingType::commodity = 1 ReadingType::flowDirection = 1 ReadingType::phase = phase ReadingType::uom = 29	701.VL1 701.VL2 701.VL3
Frequency	AI536	ReadingType::accumulationBehaviour = 12 ReadingType::commodity = 1 ReadingType::flowDirection = 1 ReadingType::uom = 33	701.Hz
Operational State	BI10-BI24	DERStatus::operationalModeStatus	701.St
Connection Status	BI10-BI24	DERStatus::genConnectStatus DERStatus::storConnectStatus	701.ConnSt
Alarm Status	BI0-BI9	DERStatus::alarmStatus	702.Alrm
Operational State of Charge	AI48	DERStatus::stateOfChargeStatus	713.SoC

to enable or disable the anti-islanding functionality of the DER in the information models, which is required for the IEEE 1547.1 Unintentional Islanding type tests. In the model review process, SunSpec adopted the *Anti-Islanding Enable (AntiIslEna)* point in the DER AC Controls Model. It is recommended this point also be added to IEEE 1815 and IEEE 2030.5 because it will provide a standardized means to conduct Unintentional Islanding experiments.

The SIRFN community is working to construct the IEEE 1547.1 tests as described in the Introduction and listed in Table 3, but it was desired to spot-check these functions in the interoperability SVP script in order to assess if there were any issues with the information models or DER simulators. The following experiments were conducted:

- **Constant Power Factor (CPF)**: SVP enabled the function and set PF to 0.90 injecting, -0.90, absorbing, and 0.85 injecting, then checked the reactive power changes, and disabled the function.
- **Active Power-Reactive Power (WV) Mode**: SVP set $P = -P' = \{0.2,\ 0.5,\ 1.0\}$ pu and $Q = -Q' = \{0.0,\ 0.0,\ -0.44\}$ pu %WMax, followed by $P = -P' = \{0.1,\ 0.6,\ 1.0\}$ pu and $Q = -Q' = \{0.0,\ -0.1,\ -0.25\}$ pu %WMax points, read them back, and disabled the function.
- **Voltage-Reactive Power (VV) Mode**: SVP enabled $V = \{0.95,\ 0.99,\ 1.01,\ 1.05\}$ pu, $Q = \{1.0,\ 0.0,\ 0.0,\ -1.0\}$ pu %VarMax and then $V = \{0.93,\ 0.98,\ 1.02,\ 1.08\}$ pu, $Q = \{0.3,\ 0.0,\ 0.0,\ -0.5\}$ pu %VarMax points, read back the VV settings, and disabled the function.
- **Constant Reactive Power (CRP) Mode**: SVP enabled the function and set the CRP limit to 25%, 59%, 87%, and 45% of nameplate injection and absorption capacities, checked the reactive power monitoring point for changes, and disabled the function.
- **Voltage-Active Power (VW) Mode**: enabling $V = \{1.03,\ 1.05\}$ pu, $P = \{1.0,\ 0.2\}$ pu and $V = \{1.05,\ 1.08\}$ pu, $P = 1.0,\ 0.5$ pu points, reading back the settings. Disabling the function.
- **Voltage Trip (VT)**: SVP set two groups of $\{V_{high}$ pu, t_{high} s$\}$ and $\{V_{low}$ pu, t_{low} s$\}$ curve points to the EUT and read them back. Group 1: $V_{high} = \{1.10,\ 1.20\}$, $t_{high} = \{13.0,\ 0.16\}$, $V_{low} = \{0.88,\ 0.50\}$, $t_{low} = \{21.0,\ 2.0\}$. Group 2: $V_{high} = \{1.17,\ 1.25\}$, $t_{high} = \{15.0,\ 1.20\}$, $V_{low} = \{0.86,\ 0.55\}$, $t_{low} = \{20.0,\ 3.0\}$
- **Frequency Trip (FT)**: SVP set two groups of $\{f_{high}$ Hz, t_{high} s$\}$ and $\{f_{low}$ Hz, t_{low} s$\}$ points and read them back. Group 1: $f_{high} = \{61.8,\ 62.0\}$, $t_{high} = \{384.0,\ 0.5\}$, $f_{low} = \{59.2,\ 58.5\}$, $t_{low} = \{299.0,\ 5.0\}$. Group 2: $f_{high} = \{61.5,\ 63.8\}$, $t_{high} = \{100.0,\ 10.0\}$, $f_{low} = \{59.6,\ 57.8\}$, $t_{low} = \{299.0,\ 5.0\}$.
- **Frequency Droop (FW)**: SVP issued $db_{OF} = db_{UF} = 0.02$ Hz, $k_{OF} = k_{UF} = 0.05$ and $db_{OF} = db_{UF} = 0.036$ Hz, $k_{OF} = k_{UF} = 0.08$ parameters, reading them back, and disabled the function.
- **Enter Service (ES) and Cease to Energize and Trip**: SVP enabled the mode with $V_{low} = 0.917$ pu, $V_{high} = 1.05$ pu, $f_{low} = 59.5$ Hz, $f_{high} = 60.1$ Hz, 300 s Random Delay, Delay, and Ramp Period; and $V_{low} = 0.88$ pu, $V_{high} = 1.06$ pu, $f_{low} = 59.9$ Hz, $f_{high} = 61.0$ Hz, 600 s Random Delay, 1 s Delay, and 1000 s Ramp Period. Note: the test criteria is for Enter Service electrical type testing, which does not include any trip testing, so this should be relabeled as to not indicate that it is a trip test.

TABLE 6. Monitoring information test operating points and criteria per IEEE 1547.1.

Monitoring information parameter	Operating Point A	Operating Point B	Criteria
Active Power	20% to 30% of DER "active power rating at unity power factor."	90% to 100% of DER "active power rating at unity power factor."	Reported values match test operating conditions within the accuracy requirements specified in Table 3 in IEEE Std 1547-2018.
Reactive Power (Injected)	20% to 30% of DER "reactive power injected maximum rating."	90% to 100% of DER "reactive power injected maximum rating."	Reported values match test operating conditions within the accuracy requirements specified in Table 3 in IEEE Std 1547-2018.
Reactive Power (Absorbed)	20% to 30% of DER "reactive power absorbed maximum rating."	90% to 100% of DER "reactive power absorbed maximum rating."	Reported values match test operating conditions within the accuracy requirements specified in Table 3 in IEEE Std 1547-2018.
Voltage(s)	At or below 0.90 × (ac voltage nominal rating).	At or above 1.08 × (ac voltage nominal rating).	Reported values match test operating conditions within the accuracy requirements specified in Table 3 in IEEE Std 1547-2018.
Frequency	At or below 57.2 Hz.	At or above 61.6 Hz.	Reported values match test operating conditions within the accuracy requirements specified in Table 3 in IEEE Std 1547-2018.
Operational State	On: Conduct this test while the DER is generating.	Off: If supported by the DER.	Reported Operational State matches the device present condition for on and off states.
Connection Status	Connected: Conduct this test while the DER is generating.	Disconnected: Conduct this test while permit service is disabled.	Reported Connection Status matches the device present connection condition.
Alarm Status	Has alarms set.	No alarms set.	Reported Alarm Status matches the device present alarm condition for alarm and no alarm conditions.

TABLE 7. Alarms in the SunSpec Modbus, IEEE 1815, and IEEE 2030.5 information models.

SunSpec Modbus 701.Alrm	IEEE 1815 BI0-19	IEEE 2030.5 DERStatus:alarmStatus
• Ground Fault • DC Over Voltage • AC Disconnect Open • DC Disconnect Open • Grid Disconnect • Cabinet Open • Manual Shutdown • Over Temperature • Frequency Above Limit • Frequency Under Limit • AC Voltage Above Limit • AC Voltage Under Limit • Blown String Fuse On Input • Under Temperature • Generic Memory Or Communication Error (Internal) • Hardware Test Failure • Manufacturer Alarm	• System Communication Error • System Has Priority 1 Alarms • System Has Priority 2 Alarms • System Has Priority 3 Alarms • Storage State of Charge at Maximum. Maximum Usable State of Charge reached. • Storage State of Charge is Too High. Maximum Reserve Percentage (of usable capacity) reached. • Storage State of Charge is Too Low. Minimum Reserve Percentage (of usable capacity) reached. • Storage State of Charge is Depleted. Minimum Usable State of Charge Reached. • Storage Internal Temperature is Too High • Storage External (Ambient) Temperature is Too High	• Over Current • Over Voltage • Under Voltage • Over Frequency • Under Frequency • Voltage Imbalance • Current Imbalance • Local Emergency • Remote Emergency • Low Input Power • Phase Rotation

- **Limit Maximum Active Power (LAP)**: SVP enabled the function and set the limit to 25%, 59%, 87%, and 45% of nameplate %WMax capacity, checked the active power monitoring point for changes, and disabled the function.

Results and discussion are provided below for each of the protocols.

1) SunSpec MODBUS

While completing these experiments, the SunSpec Modbus 700-Series Models were in TEST status and actively being updated by the committee so it was relatively straightforward to report suggested changes and have those modification made quickly. In this process, a range of issues at the SunSpec model definition, pySunSpec2, SVP Dashboard, and SVP-levels were resolved. Some Modbus points were added and removed. There were missing labels for some points. Scaling/rounding issues were fixed. Point names, data types, units, and enumerations were changed. After these modifications, the SunSpec models and DER simulator functioned as expected during the management function spot checks. Each of the settings and management function parameters were able to be written and read back effectively. To help see the Modbus parameter and interact with DER equipment, the SunSpec Alliance has created a windows program called the SVP Dashboard that allows a user to quickly read a SunSpec Modbus map from a device and make changes to the parameters using a web browser. A screen shot of this tool with the voltage-reactive power model displayed is shown in Fig. 4. Since the SVP Dashboard was constructed

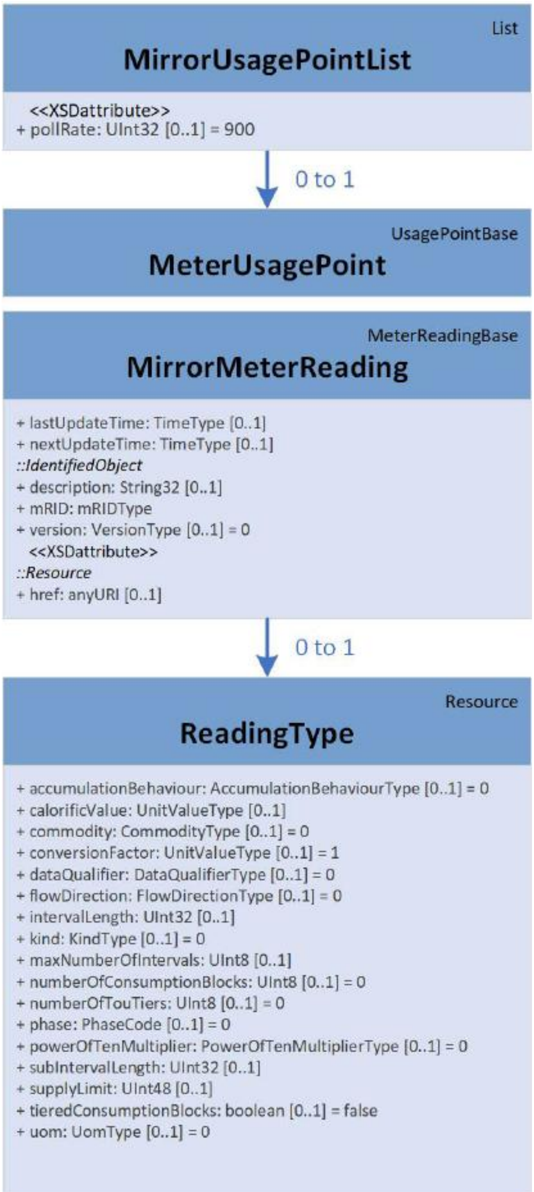

FIGURE 3. Elements of the IEEE 2030.5 XML schema for MirrorMeter used for monitoring information tests.

using the pySunSpec2 Python library like the SVP driver, the python object interactions were the same with the simulated DER. Both of these tools will need to be tested against physical DER devices that have Modbus TCP and Modbus RTU implementations to confirm the full functionality in the future. Using the SVP to automate the IOP experiments, the nameplate, configuration, monitoring, and management experiments were completed in 3 minutes 24 seconds, with a 1 second delay between write and read test steps.

2) IEEE 1815

As described before, not all the IEEE 1547-2018 functionality was included in the EPRI DER Simulator, but it did include many of the grid-support functions. The spot check on CPF confirmed that in DER generating mode overexcited and underexcited PF values could be configured and read back from the DER using the DNP3 interface. To change DNP3 curve-based functions, first the Curve Edit Selector (AI328/AO244) was used to select the curve, set the Curve Mode Type, e.g., VV, VW, etc. (AI329/AO245), number of points (AI330/AO246), the X and Y Units (AI331/AO247, AI332/AO248), and then read/write up to 100 curve point values. The Volt-Var curve index was written to AO217 to indicate which curve should be used when the function was enabled with BO29. This process was performed to store the curve. While it may be necessary for production devices to write specific curves for each of the functions, for the IEEE 1547.1 testing, all the functions used curve index 1, so that implementation errors could be quickly identified. Although, testing the storing and recalling capabilities of the DER would be necessary to certify the device for DNP3 App Note compliance.

VV, WV, CRP, VW, FW, and LAP tests were successful. During the LAP experiments, a packet capture was performed on the loopback interface using Npcap and Wireshark, as shown in Figure 5. The communication between the SVP and the DNP3 Agent were filtered out of the figure to just show the DNP3 traffic between the DNP3 Agent on port 11949 and the DNP3 outstation on port 20000. Packet 395 sets the active power level of the DER to 25% by writing AO88. There is a scaling factor in the DER that converted the 250 value to 25. Packet 435 was the direct operate command which writes a 1 to BO17 to enable the LAP function. The measured active power (AI537) and the Limit Active Power Mode setting (BI69) were requested from the outstation in packet 509, and returned to the master in packet 511. The AO writes set the active power level to 59%, 87% and 45% in packets 629, 880, and 951. The active power measurements from AI537 occur after each change. After issuing each of the active power curtailment commands, the EPRI DER simulator reduces the power output, which is reflected in the GUI and in the measured power point. A screenshot of the DER EPRI Simulator GUI interface after setting the 45% LAP command is shown in Figure 6. The vertical yellow line labeled *Wmax* in the Active-Reactive Power (P-Q) plane represents the LAP reduction in power. This simulated device was configured to represent a 250 kW PV inverter, so the 45% curtailment changed the power output to 112.5 kW, even though there was 100% DC power input available to it.

3) IEEE 2030.5

In the case of the IEEE 2030.5 spot checks, the SunSpec Server API interface was used to issue a number of changes to the Kitu and EPRI clients. For these experiments the default settings in DefaultDERControl (*dderc*) were changed for each of the management information points (e.g., grid-support function parameters) in the SunSpec Server. The settings were then read back from the server. This is not a sufficient experiment to confirm the client or DER has updated the settings–but there is no way to do this with the current

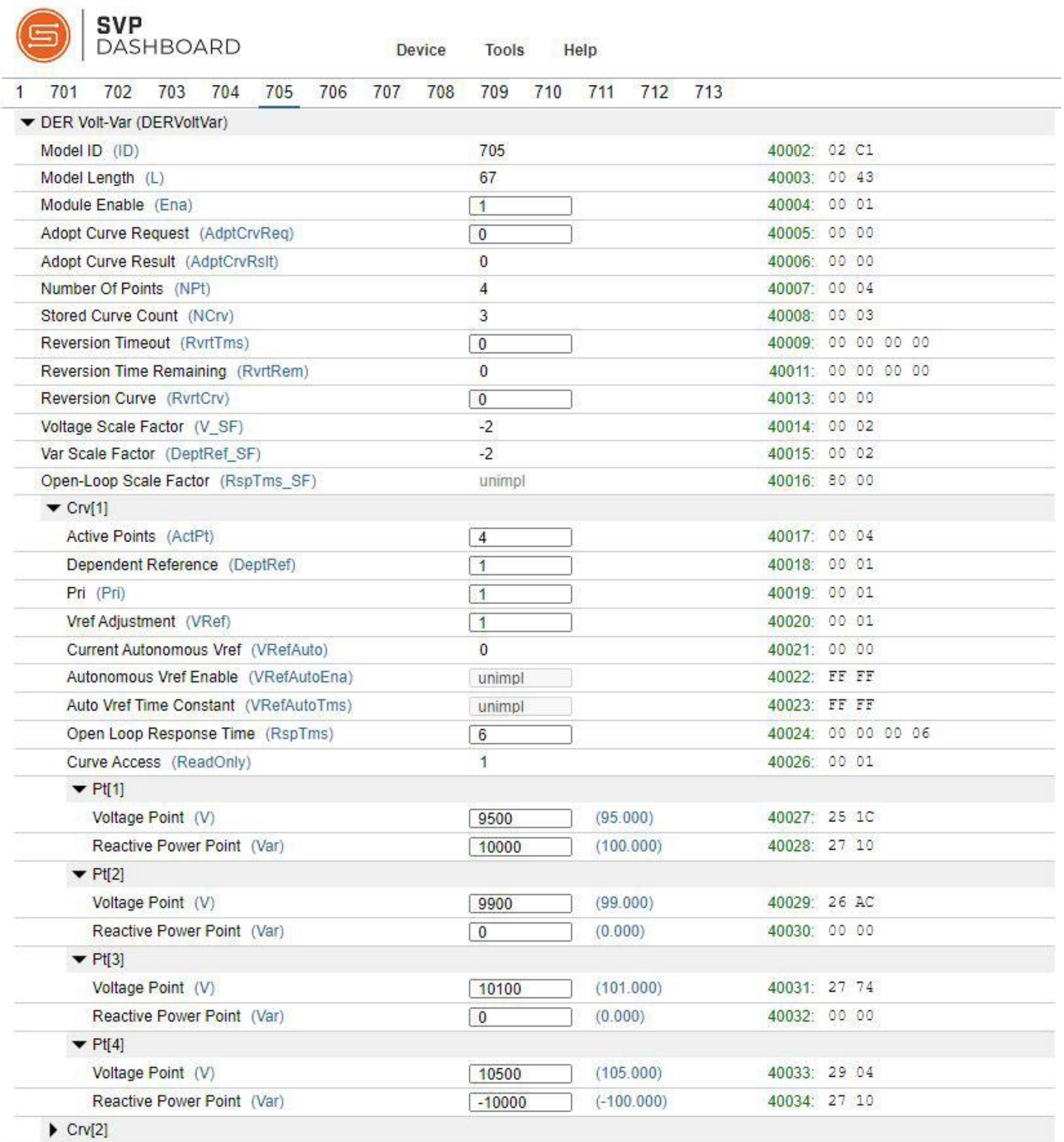

FIGURE 4. SVP dashboard displaying the Sunspec Model 705 Volt-Var settings for the simulated DER.

IEEE 2030.5 protocol. Fortunately the IEEE 1547.1 test procedure requires the electrical tests for each of these modes, to show that the client effectively updates operations. But grid operators will have to assume that the client has updated its control settings in the field. Additionally, there is no clear way to "disable" an operating mode in IEEE 2030.5. The only option is to set the control points to None, but it is ambiguous whether the client will disable that control mode or leave the default settings running in those cases.

4) GRID OPERATIONS

In additional to testing challenges, there are also a number of operational concerns that were identified through the Management Information Tests. These issues are the result of permitting multiple valid IEEE 1547-2018 interoperability implementations. From the prospective of the grid operator, they would like to send a single command to all devices and have a deterministic response. However, the optionality of some of the Management Information parameters currently makes this impossible. Two examples of this are:

- Do all DER devices need to support six points to create the P/Q and P'/Q' WV curves? In the case of a mix of four- and two-quadrant DER devices, the grid operator would want to send a single command that would include the P'/Q' points, but this command may be rejected by DER without storage. Therefore, it is

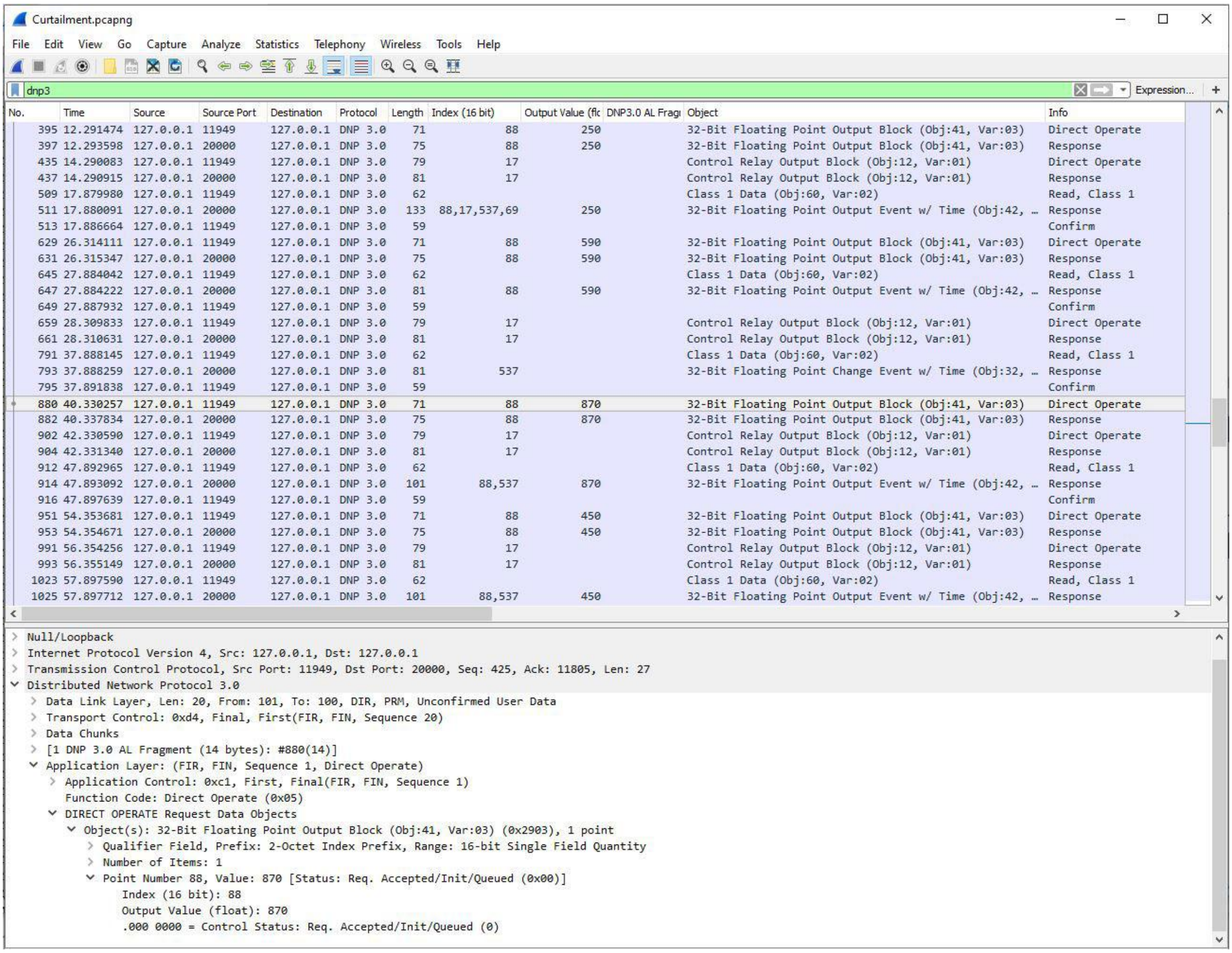

FIGURE 5. A packet capture of the DNP3 LAP experiment. AO88 is the active power curtailment value, BO17 is the limit active power enable/disable point, and AI537 is the active power measurement point.

recommended that all DER equipment support those points and, for those that do not include storage, P'/Q' points are ignored.

- DER devices historically do not support all the reactive power units (e.g., %WMax, %VarMax, %VarAval, or %VAMax) and will generate an exception if they are commanded into those modes. In fact, defining reactive power as a percentage of nameplate apparent power (%VAMax) is currently not an option in DNP3 or IEEE 2030.5, despite being the units used to define the curves in IEEE 1547 and California Electric Rule 21. If this practice were to continue, for a grid operator to send desired WV or VV operating mode to a nonhomogeneous collection of DER devices, they would first need to query all DER to know what units are supported, translate the set points according to those units, and send that data to the equipment. The use of %VarMax, while common in the inverter industry, is especially problematic because some devices may have different injection and absorption reactive power nameplate ratings or produce different levels of reactive power than required by the standard (i.e., 44% of VAMax for IEEE 1547 Category B equipment) which would likely produce unexpected and nonuniform responses from DER equipment. To promote operational clarity and interoperability, it is recommended that all the communication standards include %VAMax reactive power units and IEEE 1547 be updated with language requiring DER to support %VAMax, at minimum.

IV. STANDARD REVISION RECOMMENDATIONS

These experiments revealed a number of issues, limitations, and ambiguities with the IEEE 1547.1 test procedure and the information models. The requirements for listing products to IEEE 1547.1 are being refined in the American National Standards Institute (ANSI)-approved test procedure, UL 1741 Supplement SB, which was published September 28, 2021. UL 1741 provides additional guidance for test engineers and Nationally Recognized Test Laboratories (NRTLs) to conduct the IEEE 1547.1 type tests in order

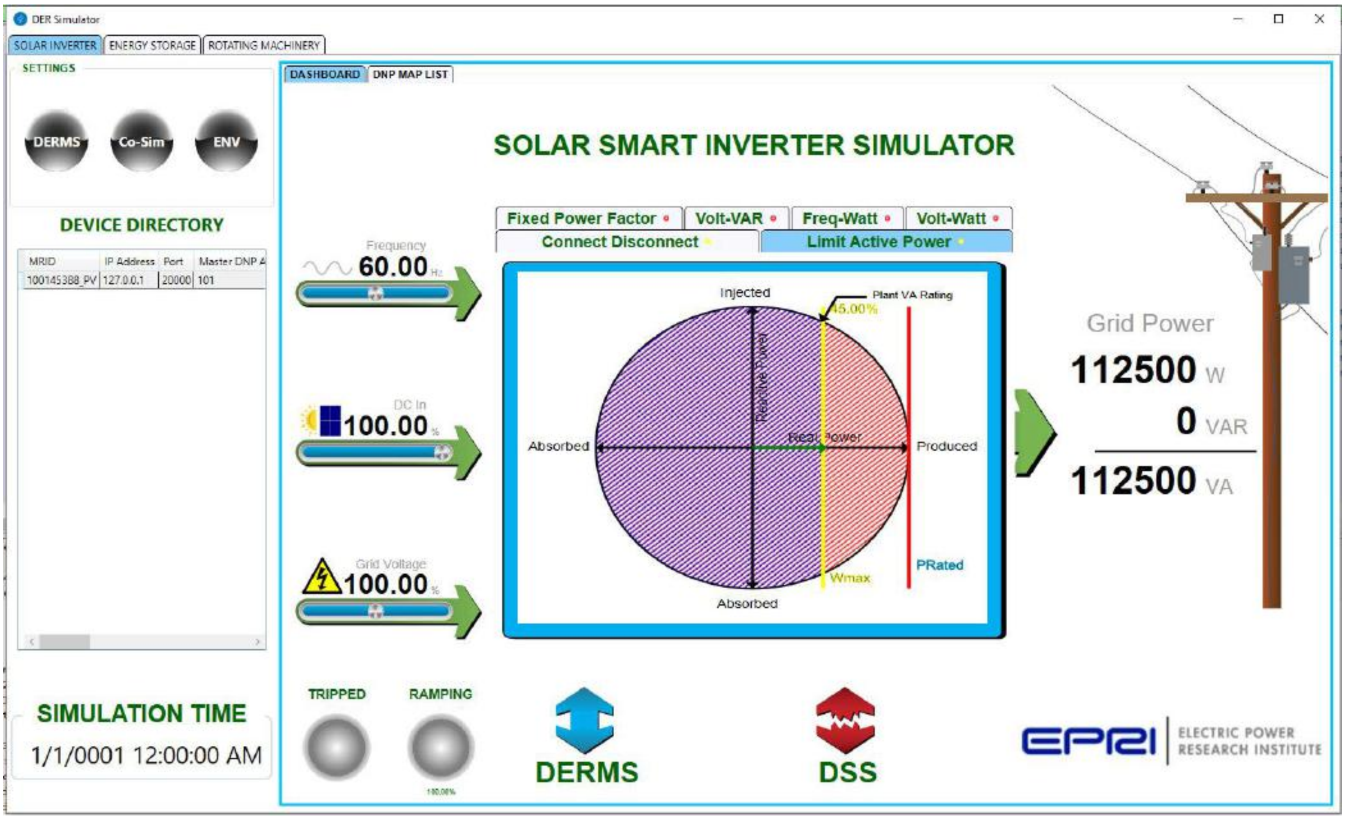

FIGURE 6. **The EPRI DER Simulator after the 45% curtailment command has been issued. The DERMS connection at the bottom indicates that the DNP3 agent is connected to the DNP3 outstation of the EPRI DER simulator.**

to list DER products. The following recommendations were provided to the committee for inclusion in UL 1741 SB and updates to future updates to IEEE 1547.1.

In addition to multiple typographical errors, there were several issues identified in the IEEE 1547 base standard, IEEE 1547.1 test protocol, the DER communication protocols, and associated information models. The following items are suggested for review by the standards development organizations and associated writing committees:

- IEEE 1547.1-2020
  - The Configuration Data Tests should use settings points for each of the protocols, not the DER nameplate points. Nameplate data should never be overwritten.
  - Add a procedure for testing the *Supported control mode functions* in the Configuration Data Test.
  - Indicate how the values are to be changed and clarify an allowable tolerance on the accuracy of the results in the Configuration Data Test.
  - It is not clear that the DNP3 management information tests required that the electrical experiments are done in accordance with IEEE 1547.1 Clause 5.
  - Explicitly state if Operational State of Charge (SoC) is in the Monitoring Information Tests.
  - Indicate how to generate the Monitoring Information Test Operating Points.
  - Clarify if the Injected/Absorbed descriptors in *Reactive Power (Injected)* and *Reactive Power (Absorbed)* Monitoring Information Operating Points indicate the active power direction or excitation.
- IEEE 1547-2018
  - The standard should be updated to clarify what curves DER devices support in order to promote broad interoperability. This includes mandating DER equipment support six points that represent the P/Q and P'/Q' IEEE 1547 WV curves.
  - IEEE 1547 should be updated to require DER include a preferred, standardized unit for reactive power, preferably %VAMax, in order to reduce the complexity of grid operator systems and minimize the chances of misoperation.
- General Information Model Recommendations
  - There is poor alignment between the information models for DER states and alarms, e.g., SunSpec Modbus 701.Alrm, the DNP3 App Note Alarms in BI0-BI9, and the IEEE 2030.5 CSIP alarms from the bit-mapped resource, DERStatus:alarmStatus. The standards development organization should work to harmonize the DER states and alarms.
- SunSpec Modbus
  - Through the course of this research, a number of issues were identified in the SunSpec

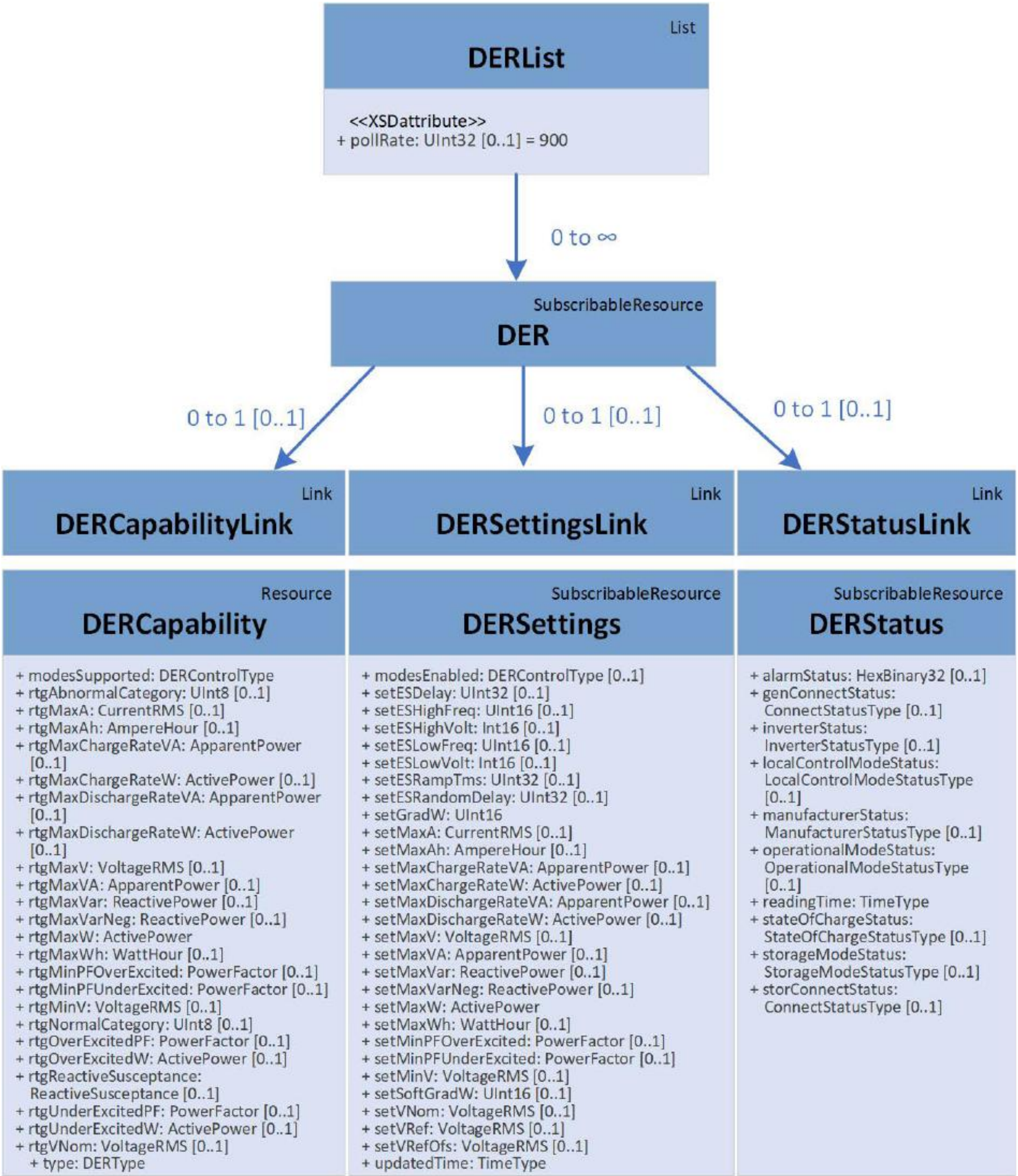

FIGURE 7. Elements of the IEEE 2030.5 XML schema for the DER SubscribableResource used for nameplate data and configuration data tests; [*a*..*b*] indicates there can be between *a* and *b* elements.

Modbus 700-series models and pySunSpec2. This work was performed while the SunSpec models were in TEST status, so those issues could be logged as GitHub issues, and brought to the committee for revision. These included missing points, naming conventions, selection of data types, problems with scale factors, etc. Each were addressed by the SunSpec Models Working Group before going to APPROVED status in April 20, 2021.

- IEEE 1815
  - The DNP3 App Note should add Manufacturer, Model, Serial Number, and Version Data to the AI points.
  - The DNP3 information model should to be updated with AO and BO setting points to adjust the configuration data in IEEE 1547.1.
  - Add Anti-Islanding Enable/Disable point.
  - Add %VAMax to list of optional reactive power units.

- IEEE 2030.5
  - IEEE 2030.5 simply adopts allowed HTTP/HTTPS layer usage patterns for client-server interactions, but clearly indicating that there should be no expectation that sessions will persist would be helpful for improving interoperability. Some implementations may open a session and continue to use that session for multiple GET/POST/PUTs, whereas other implementations may open/close a session for each GET/POST/PUT. Clients and servers must be able to handle any allowed usage pattern.
  - There is no clear IEEE 2030.5 mechanism to disable controls.
  - There is no visibility into the operating mode of the client/DER. Adding a means to check on the current operating conditions of the client would help support interoperability testing.
  - Add Anti-Islanding Enable/Disable point.
  - Add %VAMax to list of optional reactive power units.

V. CONCLUSION

The DER and power industry is undergoing a monumental transition with the adoption of the interoperability requirements in IEEE Std. 1547-2018. All devices entering American market sectors will soon be required to have a standardized SunSpec Modbus, IEEE 1815 (DNP3), or IEEE 2030.5 communication interface. In order to prepare for type testing DER devices to the IEEE 1547.1 conformance requirements and providing recommendations back to the standards development organizations, a new IEEE 1547.1 interoperability script and associated communication drivers were created for the System Validation Platform (SVP). This test script was executed against DER simulators running each of the protocols. In this process, the team unearthed multiple issues with the IEEE 1547.1 test procedure, the information models, pySunSpec2, and the DER simulators running each of the protocols. These issues have been raised with the appropriate companies and committees to address these concerns and streamline the roll-out of advanced inverters. The SVP can also be used by DER vendors and nationally recognized testing laboratories to efficiently complete these experiments, thereby reducing the costs for developing these new products and listing them to the revised IEEE 1547.1 standard.

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NREL

A Primer on the Unintentional Islanding Protection Requirement in IEEE Std 1547-2018

David Narang,[1] Sigifredo Gonzalez,[2] and Michael Ingram[1]

1 National Renewable Energy Laboratory
2 Sandia National Laboratories

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Cover Photos by Dennis Schroeder: (clockwise, left to right) NREL 51934, NREL 45897, NREL 42160, NREL 45891, NREL 48097, NREL 46526.

Preface

The revised Institute of Electrical and Electronics Engineers 1547-2018 Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces (IEEE Std 1547-2018) was published in April 2018. This standard is one of the foundational documents in the United States needed for integrating distributed energy resources (DERs), including solar energy systems, and energy storage systems with the electric distribution grid.

The revised standard contains 11 chapters (clauses) and 8 annexes that comprise 136 pages. The revision is significantly different from the 2003 version, and it contains new concepts and new technical requirements. Each clause specifies information or requirements that apply to certain aspects that are important to the interconnection of DERs to the electric power system. Implementing the requirements necessitates a careful study of the underlying technical concepts and requires appropriate information to calculate relevant settings and configurations.

Various stakeholders have different roles in implementing the standard, and portions of the standard are directed toward a specific audience who must possess specialized information and technical training to use and apply the requirements.

This document provides informative material on the requirements related to unintentional islanding in IEEE Std 1547-2018, with the intent to equip the reader with basic knowledge and background information to improve understanding and use of the requirements specified.

Note that this document reflects the authors' interpretations, which in some instances might differ from one person to another; therefore, this work is intended to supplement the existing and growing body of knowledge[1] across the U.S. electric sector on the use and application of this important standard.

[1] Additional educational material can be found at https://www.nrel.gov/grid/ieee-standard-1547/.

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List of Acronyms

AGIR	Authority Governing Interconnection Requirements
DER	distributed energy resource
DTT	direct transfer trip
EPS	electric power system
IEEE	Institute of Electrical and Electronics Engineers
PG&E	Pacific Gas & Electric Company
PV	photovoltaic
VAR	volt-ampere reactive

Table of Contents

List of Figures

Introduction

In the revised Institute of Electrical and Electronics Engineers 1547-2018 Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces (IEEE Std 1547-2018), Clause 8.1 contains requirements for distributed energy resource (DER) responses to unintentional islanding conditions. This is also referred to as anti-islanding protection.

An island is a condition in which a DER continues to energize a portion of the power system when it is electrically isolated from the utility source. If unplanned, this *unintentional islanding* condition could become harmful to connected equipment because the DER might not be designed to maintain frequency and voltage without a utility source. In addition, the unintentional island could present a hazard to utility workers or other people in the area who are unaware of the electrically energized island (Seguin et al. 2016).

IEEE Std 1547-2018 Clause 8.1 is only half a page; however, the topic of unintentional islanding has historically been and continues to be of high concern and debate in the industry. The issues around this phenomena were eloquently stated by Bas Verhoeven in a 2002 study under the International Energy Agency:

> Many international forum discussions have been dealing with 'Islanding'. …
>
> A general conclusion of these discussions was that views on the subject are very polarised. On the one hand, the islanding phenomenon is considered such a rare or improbable event that it does not merit special consideration. On the other hand, the mere theoretical possibility of unintentional islanding, confirmed in laboratory experiments, is sufficient for individuals to have great concerns over the possibility of islanding. The reality probability lies somewhere between the two extremes. An important issue here is the lack of any real data on how often and for how long islanding can occur in practice and the associated risk of occurrence. An important observation in the discussion about islanding is that the discussion is based on "personal feelings" and/or "intuition", which make the discussions even more difficult.

This document is intended to provide an overview of the subject to aid the reader in discussions and understanding. The intended audience includes electric utilities—area electric power system (EPS) operators; testing agencies[2]; solar and other DER developers, integrators, and installers[3]; and Authorities Governing Interconnection Requirements.[4] We hope that other stakeholders will also find it valuable.

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[2] The term *testing agency* includes entities such as nationally recognized testing laboratories.

[3] Solar and other DER device manufacturers are inherently interested in the performance requirements in IEEE Std 1547-2018; however, this document focuses on the application of the standard rather than the manufacturing processes of DER devices.

[4] The term *Authority Governing Interconnection Requirements* (AGIR) is defined in IEEE Std 1547-2018 as a "cognizant and responsible entity that defines, codifies, communicates, administers, and enforces the policies and procedures for allowing electrical interconnection of DER to the Area EPS. This may be a regulatory agency, public

This document is intended as a supplement to material already published or in development,[5] and it is not intended as an exhaustive resource on technical implementation; rather, topics are presented at a level that is appropriate to serve individuals who require an introduction or technical refresher to the material.

IEEE Std 1547-2018 assumes that the reader possesses the appropriate training and experience necessary to understand and apply the stated requirements. This could include foundational electrical engineering knowledge; knowledge of area EPS device settings, parameters, and operational practices; and knowledge of general and specific DER capabilities relevant to the subject.

Anti-islanding protection is required for all DERs that comply with IEEE Std 1547-2018 and UL 1741, Standard for Safety for Inverters, Converters, Controllers, and Interconnection System Equipment for Use with Distributed Energy Resources. Specifically, according to IEEE Std 1547-2018, if an unintentional island is formed by the DER, the DER must detect the island and go offline[6] within 2 seconds of the formation of the island.

The most common DERs are photovoltaic (PV) or battery energy storage systems, and these DERs are inverter based; therefore, numerous studies have focused specifically on these types of DERs. This document uses the term *DER* to apply to all types of DERs, and the more specific terms *PV* or *inverter* refer to inverter-based DERs.

How Can Unintentional Islands Form?

Several conditions could potentially cause unintentional islanding. Examples given by Bower and Ropp (2002) include:

- A fault on the area EPS that results in opening a disconnecting device, but the fault is not detected by the PV inverter or by local DER protection devices
- Equipment failure that causes an accidental opening of a disconnecting device
- Utility switching of distribution line and loads; intentional disconnection of the distribution line for utility service or repair
- Human error
- Bad actor with malicious intent

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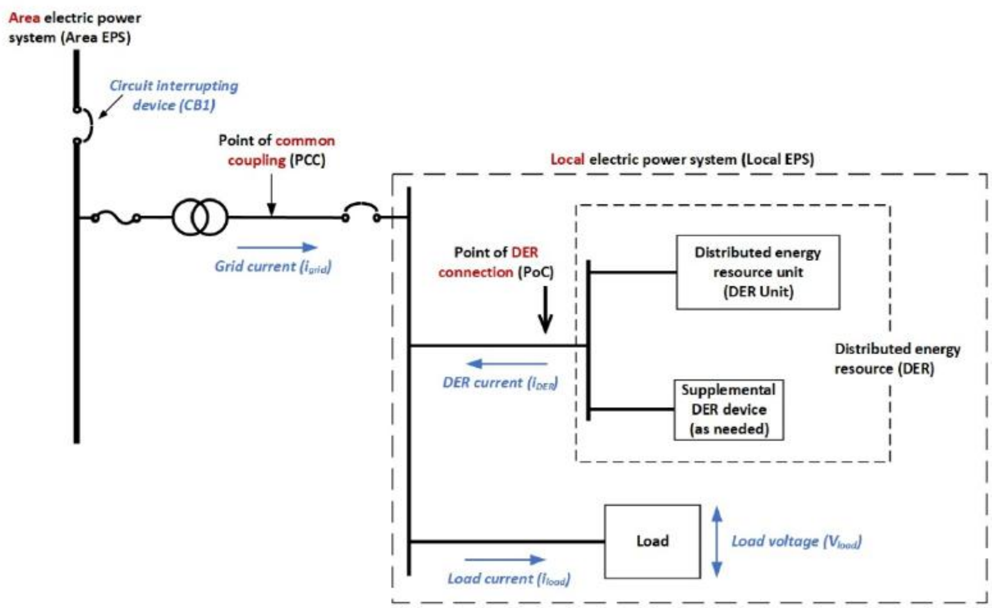
utility commission, municipality, cooperative board of directors, etc. The degree of AGIR involvement will vary in scope of application and level of enforcement across jurisdictional boundaries. This authority may be delegated by the cognizant and responsible entity to the Area EPS operator or *bulk power system* operator. NOTE—Decisions made by an authority governing interconnection requirements should consider various stakeholder interests, including but not limited to Load Customers, Area EPS operators, DER operators, and *bulk power system* operator" (IEEE 2018).

[5] For example, the upcoming revision to IEEE Std 1547.2 - IEEE Application Guide for IEEE Std 1547, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems (expected in 2022).

[6] The wording in IEEE Std 1547-2018 is very specialized and includes other defined terms, such as *cease to energize* and *trip*.

- An act of nature.

Consider Figure 1. In a typical local EPS supplied by a DER such as a PV system, the inverter controls its electrical current output magnitude and phase with respect to the voltage it sees at its output terminals, called the "point of DER connection" in IEEE Std 1547-2018. This current is supplied to the local DER load. Note that a local EPS could be configured in a variety of ways. For example, it could contain only load, only a single DER (DER unit), multiple DERs, DERs with or without supplemental DER devices, and so forth. See IEEE Std 1547-2018 Figure 2 for a full explanation.



Source: Adapted from Kroposki 2016; Ropp and Ellis 2013; and IEEE 2018

Figure 1. Block diagram of DER interconnection illustrating unintentional islanding concepts

The circuit breaker in the diagram (CB1) could be any type of circuit isolation device, and it represents any point on the distribution line between the substation and the DER installation along which normal power flow could be interrupted. If this device is opened, the DER is isolated from the grid. The circuit isolation device is often associated with fault protection and is the most common type of isolation device. The condition that invokes a response from the protection device is a fault that is significant and immediate enough to cause the protection device to trip, open, and isolate the source and loads. This creates a dynamic condition on the circuit, with the voltage and frequency fluctuating considerably, thus making it less probable to match power and meet the reactive power resonance requirements to sustain an islanding event. When the isolation device is operated for a maintenance event, the dynamic variability is mostly removed, and there could be a condition where the current flowing through the isolating device is low enough to maintain sufficient active and reactive power matches; and while the matches are still needed, the variability aspect is removed. For fault conditions that cause the isolation devices to trip, the DERs are designed to turn off to prevent an islanded condition; however, there are some conditions under which an island could form and persist. These conditions must occur at the exact moment the device opens, and they include the following:

- The grid current must be nearly zero—that is, the PV system must be producing nearly the same amount of power that is required for the load to operate.
- The power from the DERs must have the correct amount of active and reactive power required by the load.
- The reactive current must have capacitive and inductive components that resonate near 60 Hz.

DERs use various anti-islanding methods to detect and quickly disconnect in case a potentially stable island is formed. IEEE Std 1547-2018 and related standards IEEE Std 1547.1-2020 and UL 1741 require all DERs to meet robust anti-islanding functional requirements and testing before they can be deployed in the field.

Summary of Inverter-Based Anti-Islanding Protection Methods

Inverter-based DERs, such as PV and storage systems, feature built-in protection mechanisms that detect when they have become islanded from the distribution grid. Inverters have traditionally used a number of anti-islanding protection methods that have been classified as either passive or active. Modern inverters do not rely solely on passive methods.

Passive methods for islanding detection resident in the inverter are designed to monitor the electrical parameters at the point of DER connection. Upon detecting an abnormal condition, the inverter ceases power conversion. As noted by Bower and Ropp (2002), typical monitored conditions are:

- Over-/undervoltage and over-/underfrequency detection[7]
- Voltage phase jump detection
- Voltage harmonics detection
- Current harmonics detection.

Active methods of islanding detection in inverters are based on the logic that the inverter should not be able to affect certain electrical parameters as much as the larger area EPS—unless the inverter is operating in an island. These methods are designed to deliberately create small changes or disturbances at the point of DER connection. The response is analyzed to determine whether the inverter has been able to affect specific parameters—and if so, it is assumed that an island has occurred, and the inverter ceases power conversion. Common methods of active anti-islanding detection noted in literature include[8]:

- **Impedance measurement**
- **Impedance detection at a specific frequency**
- **Slip-mode frequency shift**

[7] Note that the informative footnote 111 in IEEE Std 1547-2018 states: "Reliance solely on under/over voltage and frequency trip is not considered sufficient to detect and cease to energize and trip" (IEEE 2018).
[8] DER inverter manufacturers might also employ proprietary methods that use other techniques or combinations of the techniques mentioned here.

- **Frequency bias/Sandia frequency shift**
- **Sandia voltage shift**
- **Frequency jump**
- **Mains monitoring units with allocated all-pole switching devices connected in series**[9]

[9] Sometimes referred to as *MSD*, "main monitoring device" or *ENS*, the German abbreviation for mains monitoring units with allocated switching devices.

1 Functional Requirements in IEEE Std 1547-2018

IEEE Std 1547-2018 Clause 8.1 is directed primarily to area EPS operators, DER manufacturers, testing agencies, commissioning agencies,[10] and DER operators. A DER connected to the area EPS must meet the unintentional islanding requirements of Clause 8.1 which contains three subclauses.

1. Clause 8.1.1 describes the islanding condition and the requirement for DER response: Upon formation of an island (the moment the DER is separated from the area EPS), the islanding DER must respond by ceasing to energize and tripping[11] within 2 seconds after the formation of an island. The 2-second response time is called the clearing time. By default, the clearing time is set to be 2 seconds. Not only must the DER detect the island within 2 seconds, but it must also trip. Upon trip, the DER will intentionally stay disconnected for a specified time. This intentional delay, called the *return-to-service delay*[12] is by default set to 5 minutes under IEEE Std 1547-2018. The delay can be adjusted by mutual agreement between the area EPS operator and the DER operator.
2. Clause 8.1.2 states the clearing time can be adjusted to be between 2 and 5 seconds by mutual agreement between the area EPS operator and the DER operator.
3. Clause 8.1.3 directs the reader to Clause 6.3, which requires the implementation of "appropriate means" to prevent damage or unacceptable disturbances to the area EPS if it automatically recloses on an islanded circuit. Damage or unacceptable disturbances could result if there are differences in instantaneous voltage, phase angle, or frequency between the islanded system and the area EPS at the instant a recloser operates (IEEE 2018).

Clause 8.1.1, Clause 8.1.2, and Clause 8.1.3 comprise the unintentional islanding requirements in IEEE Std 1547-2018. Because of the safety nature of these requirements, however, extensive effort is made to verify this functionality, and in some jurisdictions, additional safeguards are put into place to supplement these unintentional islanding prevention requirements.

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[10] A commissioning agency could include the DER vendor, the system integrator, the local utility, or other qualified and authorized entity.

[11] *Cease to energize* is a specialized term that applies at the point of DER connection, defined as a "cessation of active power delivery under steady-state and transient conditions and limitation of reactive power exchange." This function can be caused to operate for a variety of reasons. In the case of unintentional islanding, it is followed by a *trip*, another specialized term, which is defined as an "inhibition of immediate return to service, which may involve disconnection" (IEEE 2018).

[12] The return-to-service delay is typically changed to much shorter times when type testing a DER to expedite the unintentional islanding testing procedure.

2 Factory Testing and Certification

IEEE Std 1547-2018 requires DERs to detect and cease to energize the area EPS and trip within 2 seconds of the formation of an island. For most types of residential and commercial DERs, this requirement is built into the DERs by manufacturers, and this capability is thoroughly tested prior to field deployment.[13]

In the United States, this "type testing" typically occurs by an approved testing agency[14] at the DER manufacturer's factory or at a special testing laboratory, and it is carried out on a single piece of equipment (DER unit) that represents the specific model of the manufactured DER. The testing is valid for other DERs in the product family of the same design.

In the United States, type testing is typically done in conjunction with equipment certification. Type tests are completed according to the procedures specified in IEEE Std 1547.1-2020, and the testing agency records the applicable test criteria and results. For DER interconnections, the primary means of equipment certification is via UL 1741, Standard for Safety for Inverters, Converters, Controllers, and Interconnection System Equipment for Use With Distributed Energy Resources.

Certified equipment is installed following the requirements of the National Fire Protection Association 70 (National Electric Code) to ensure that sound equipment installation practices contribute to the safe operation of the equipment. Additional jurisdiction-specific requirements might also be applied via local interconnection rules. This implementation is illustrated in Figure 2.

Under UL 1741, anti-islanding protection testing is conducted after all grid support functions[15] are tested. This ensures that the equipment being tested can perform all the grid support functions as designed and that it can pass the unintentional islanding tests with grid support functions, such as voltage and frequency support functions along with the mandatory voltage and frequency ride-throughs. The IEEE Std 1547.1-2020 test matrix is an exhaustive test procedure and combines various grid support functionalities and power levels to ensure that the DER can detect the loss of the utility under unique balanced conditions. For these tests, the method of isolation is the opening of an isolation device, such as conditions occurring under a routine maintenance isolation condition, i.e., a fault is not introduced to cause a protection device to trip/actuate.

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[13] Certain types of DERs that contain supplemental DER devices might need to be field-certified.

[14] A nationally recognized testing laboratory, certified by the Occupational Safety and Health Administration, is an example of a testing agency.

[15] Examples of grid support functions include active and reactive power control voltage ride-through and frequency ride-through.

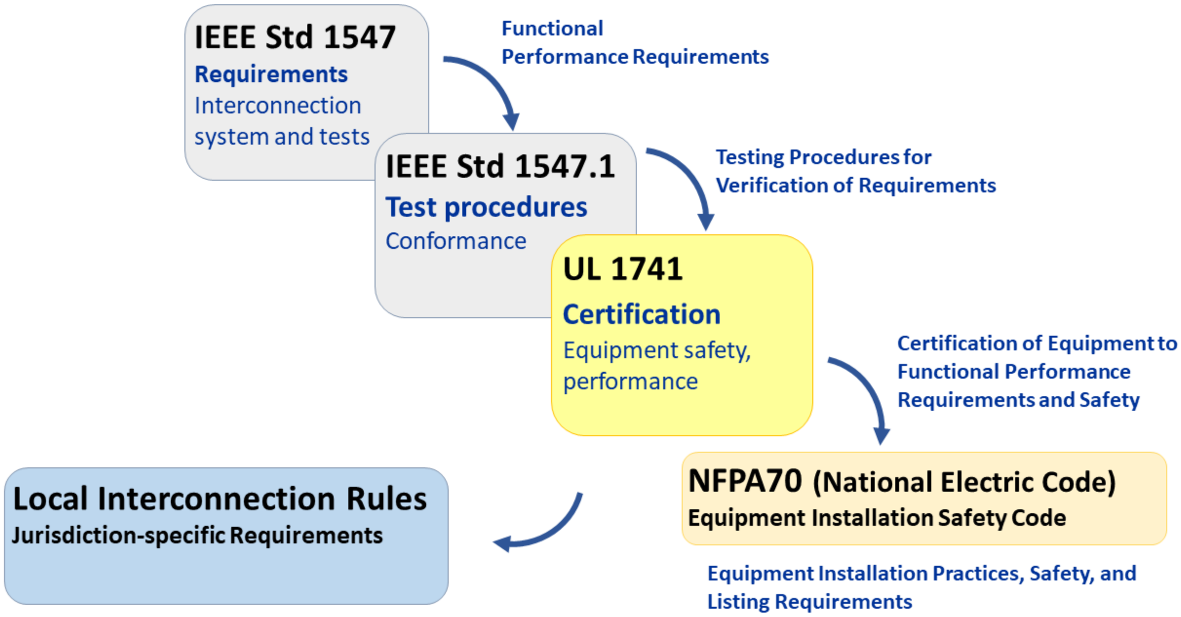


Figure 2. Implementation of IEEE Std 1547-2018 and related standards in the United States

IEEE Std 1547.1-2020, which was approved in March 2020, specifies the conformance testing and evaluation procedures that are exercised to establish and verify compliance with the technical functional requirements of IEEE Std 1547-2018.

UL 1741 was updated to reflect the revised performance and testing requirements in IEEE Std 1547.1-2020. The revision was published on August 3, 2020. The revised testing requirements are included in Supplement B, UL 1741-SB.[16]

As summarized in IEEE Std 1547.1-2020, one or more samples of the DER must pass the applicable type tests. Performance requirements not verifiable through type tests must be verified by other means, such as DER evaluation and commissioning tests. Each DER unit or supplemental DER device must pass all required production tests. The design evaluation phase of the interconnection process will determine whether any additional testing or evaluation must be made either during the design evaluation, through installation evaluations, and/or through commissioning tests. Additionally, any required periodic tests and verifications are to be performed in the field (IEEE 2020).

Most type testing of DER unintentional islanding functionality is performed under worst-case conditions to fully challenge both the capability of the DER to detect when an unintentional islanding event has occurred and to challenge the DER's ability to take the required actions.

[16] Please see https://sagroups.ieee.org/scc21/standards/1547rev/ for a timeline for the rollout of DERs that comply with IEEE Std 1547-2018.

Unintentional islanding testing is conducted with grid support functions enabled and with the DER operating in different modes, i.e., unity power factor, non-unity power factor, and constant reactive power operation. These operating modes coupled with voltage regulating functions and frequency regulating functions can challenge some of the unintentional islanding methods; therefore, voltage and frequency ride-through and voltage and frequency regulating functions must be determined prior to conducting unintentional islanding assessments. If unintentional islanding evaluations result in nonconformance, an investigation must be performed to identity the function that creates the nonconformance.

DER manufacturers can use a variety of methods[17] to detect an islanding condition. IEEE Std 1547.1-2020 Clause 5.10 specifies the required type tests to verify the unintentional islanding functionality.

The DER and any supplemental equipment being tested, referred to as "equipment under test" by IEEE Std 1547.1-2020, may use multiple methods of unintentional islanding detection. Commonly implemented methods[18] use some form of voltage and frequency threshold to detect when an islanding condition exists. Various tests have been designed to evaluate how well these methods perform as part of the type testing regimen.

2.1 Balanced Generation-to-Load Test

The balanced generation-to-load test, described in Clause 5.10.2, can be used for any type of equipment. Passing this test achieves full compliance with the unintentional islanding requirements. This test is conducted to verify that when an unintentional islanding condition occurs, the DER responds correctly—namely, by ceasing to energize the area EPS—and trips. Tests are conducted on a single DER under various power levels.

A simplified drawing of the test configuration is illustrated in Figure 3. The test can be conducted using a power-hardware-in-the-loop approach that allows the testing agency to use software and hardware to simulate some of the devices that are external to the DER.

[17] Passive and active methods are not limited to the methods mentioned here; however, some common passive methods include over-/undervoltage and over-/underfrequency, voltage phase jump, voltage/frequency harmonic distortion, rate of change of frequency, and rate of change of active power. Some common active methods include impedance detection, positive-feedback Sandia frequency shift, and impedance detection plus positive feedback.
[18] IEEE Std 1547-2018 notes that additional methods may be used to provide unintentional islanding protection, such as direct transfer trip or radio or cellular communications channels; however, type testing those methods was considered out of scope of the standard.

Source: Based on IEEE Std 1547.1-2020 (Figure 7)

Figure 3. Single-line drawing of the setup for a balanced generation-to-load test

This test relies on the principle that for an island to persist, the DER must be generating at or very near[19] the same active and reactive power that the load requires in the islanded portion of the system, and some mechanism must exist to maintain the islanded frequency at or very near 60 Hz. For testing conditions, therefore, a worst-case condition is a generation-to-load balance that contains both active and reactive power generation with load components that are tuned to match the DER generation power levels and resonate at or near 60 Hz to provide the system frequency.

2.2 Power Line-Conducted Permissive Signal Test

This method of anti-islanding protection relies on a signal conducted on the distribution primary line. As long as the signal is present, the DER has permission to operate. If the signal is discontinued, the DER must cease to energize the area EPS and trip within the required time.

The power line-conducted permissive signal test—applicable to DERs that use this method—is described in IEEE Std 1547.1-2020 Clause 5.10.3. For DERs that use this method, additional evaluation is required because this method uses equipment beyond what is tested in the type test; therefore, passing this test achieves only partial compliance with the unintentional islanding requirements. The additional evaluation needed to obtain full compliance is specified in IEEE Std 1547.1-2020 Clause 8.1.2.

During type testing, the testing agency simulates a permissive signal and its interruption. If the DER responds appropriately within the designated time, it passes the type test. As noted, however, because this test requires the permissive signal to be effective, the type test alone does not verify full compliance with the unintentional islanding requirements. Additional verification is required during the DER evaluation phase, at which time additional required equipment or methods are applied, such as a permissive signal provided by the area EPS operator.

[19] Voltage and frequency operating ranges allow for a slight mismatch, and the output power of the DER is never exactly constant because of maximum power point tracking and variations of the grid voltage and frequency.

2.3 Permissive Hardware-Input Test

The permissive hardware-input test—applicable to DERs that use this method—is described in IEEE Std 1547.1-2020 Clause 5.10.4. For DERs that use this method, additional evaluation is required because this method uses equipment beyond what is tested in the type test; therefore, passing this test achieves only partial compliance with the unintentional islanding requirements. The additional evaluation is specified in Clause 8.1.2.

DERs that use this method of unintentional islanding detection have a dedicated hardware control input that is used to provide permission to operate. (Note that the hardware control signal itself is generated by external means, and it is not tested in this procedure.[20])

Similar to the power line-conducted permissive signal test, this test requires external input to be effective—in this case, the hardware control input; therefore, the type test alone does not verify full compliance with the unintentional islanding requirements. Additional verification is required during the DER evaluation phase, at which time additional required equipment or methods are applied, such as a direct transfer trip (DTT) input provided by the area EPS operator.

2.4 Reverse or Minimum Import Active Power Flow Test

The reverse or minimum import active power flow test (including tests for magnitude and time), applicable to the DERs that use this method, is described in IEEE Std 1547.1-2020 clause 5.10.5. Passing this test achieves full compliance with the unintentional islanding requirements.

DERs that use this method have a function that senses the power flow between the point of connection and the point of common coupling. Using this function, the DER is permitted to operate only if power is flowing from the area EPS to the DER installation or if the power is flowing at a predetermined minimum level. If the power flow reverses or falls below the minimum level, the DER is disconnected from the area EPS. Type testing includes verification of the accuracy of the minimum power setting and the speed of the DER response.

[20] Examples of a DTT and a conducted power line signal are given in IEEE Std 1547-2018.

3 Field Evaluations and Verifications

In addition to type testing, verification of performance might be required during the DER's interconnection life cycle. A high-level view of the varieties of testing and verification is illustrated in Figure 4, with type testing shown at the bottom of the figure as the first level of evaluation. Unintentional islanding protection must be verified for all DERs during the design evaluation phase and/or during commissioning tests.

A design evaluation is a desk study typically conducted by electric utility engineers as part of an interconnection review process. The main purpose of the design evaluation is to verify that the overall DER system meets the requirements specified in IEEE Std 1547-2018 and any other interconnection requirements specified by the utility. Evaluations could be as simple as an engineering review of the DER system's design, components, and certification, or it could involve a more detailed study, such as modeling and simulation of the DER system. There could be multiple evaluations if the design of the DER changes any time during the interconnection process.

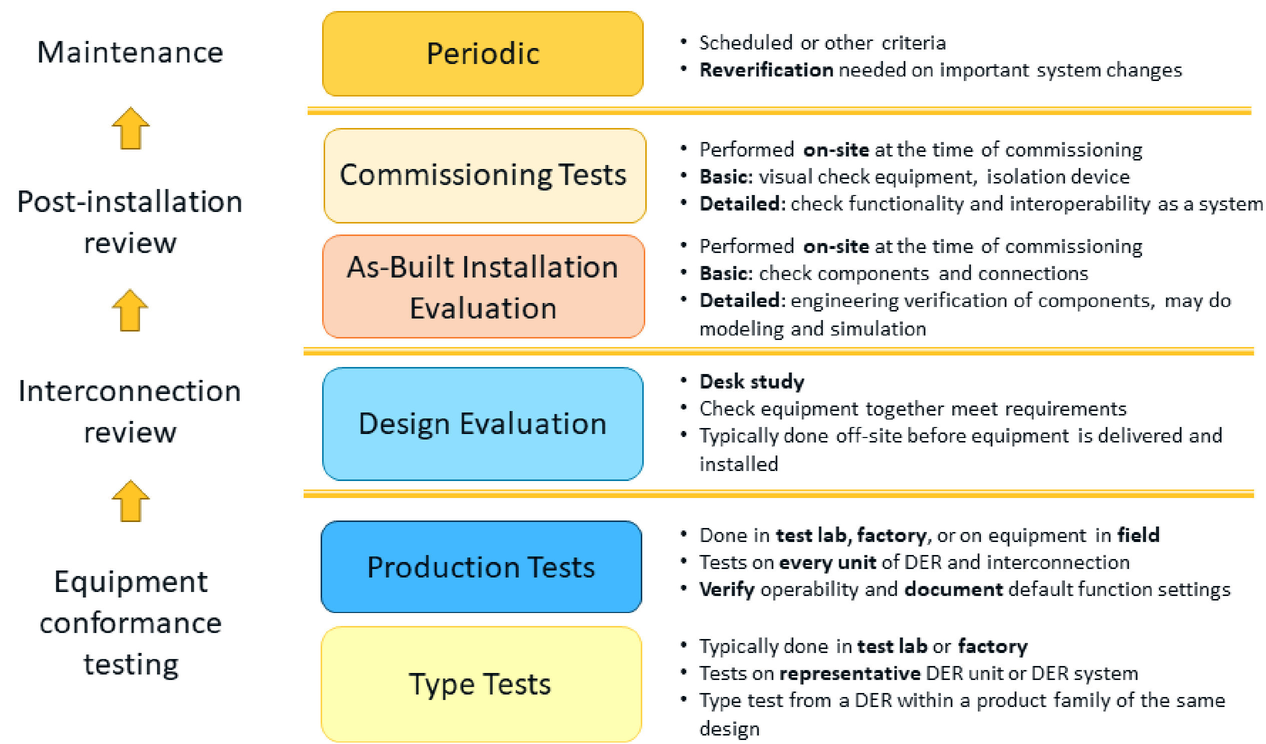


Figure 4. Varieties of testing and verification for DER interconnection

4 Common Concerns

Concerns related to unplanned islands have been noted in several publications, including Bower and Ropp (2002), IEEE (2008), Walling and Miller (2002), Barker and De Mello (2000), and Stevens et al. (2000). The top utility concerns from unintentional islanding are maintaining personnel safety and avoiding harm to customer and utility equipment. Additional concerns are also being debated, especially in locales with high shares of DERs.

4.1 Personnel Safety

The main concern for personnel safety is that if the DER's onboard unintentional islanding detection should fail and an unintentional island occurs and becomes sustained, the connected and energized electrical lines pose a risk of exposure to electricity hazards for utility workers and the public if the lines are contacted and presumed to be de-energized.

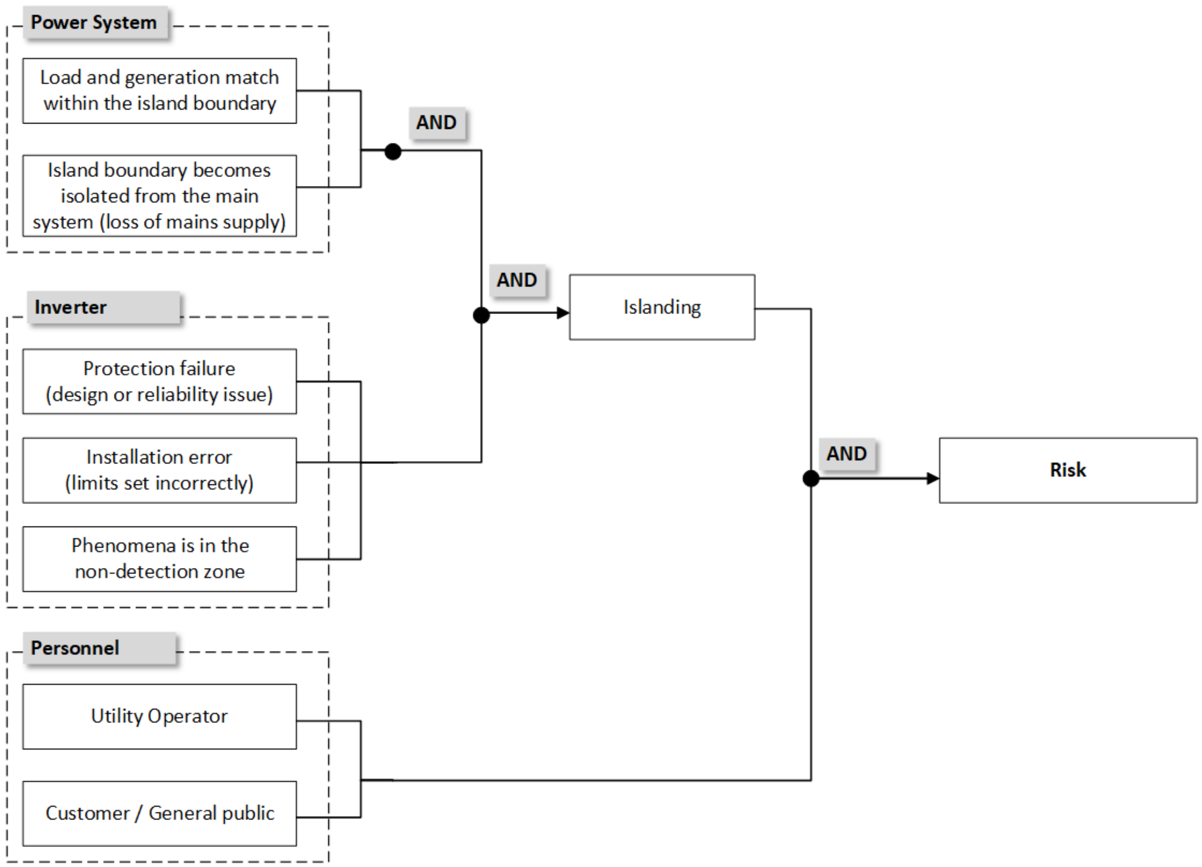
An exhaustive study of personnel risk from all types of DERs has not been identified as of this writing; however, several studies have been done for PV systems. One study conducted in 2002 under the International Energy Agency concluded that the risk of electric shock from an islanded PV system under worst-case PV penetration scenarios is less than the "benchmark" risk that already exists for utility personnel and customers.[21] The study concluded, "the additional risk presented by islanding does not materially increase the risk that already exists as long as the risk is managed properly" (Cullen, Thornycroft, and Collinson 2002).

This same study noted that prudent good practice measures could be taken to properly manage the risk, including proper signage; information and education of utility personnel and customers about the risks; and appropriate utility personnel work practices and procedures, such as testing circuits prior to work (Cullen, Thornycroft, and Collinson 2002). Further, the authors recommended that "[s]ince LOM [loss of mains] functionality is included in many PV inverters already, it is appropriate to maintain this requirement, but emphasis should be put on simple, robust, verifiable and cost-effective solutions (e.g., software-based)" (Cullen, Thornycroft, and Collinson 2002).

Note that the measures listed are predominantly for utility personnel. These measures may not adequately address other types of risk to the general public that are prevalent from electrical equipment from downed conductors, such as electrocution and wildfire. These types of risk have existed and will likely continue to exist regardless of the presence of DERs on the circuit.

The authors developed an evaluation and quantification of the risk based on a PV risk analysis "fault tree," shown in Figure 5. As illustrated, risk from an islanded system depends on several factors that must exist simultaneously.

[21] The risk of shock from islanded PV systems was found to be near 10^{-9} per year for an individual person compared to the benchmark risk of near 10^{-6} per year.



Source: Based on Cullen, Thornycroft, and Collinson 2002

Figure 5. PV Islanding risk analysis fault tree

The subject of unintentional islanding is under constant debate, according to Woyte et al. (2003):

> For low-density of PV generation, islanding is virtually impossible since load and generation never match.
>
> For networks with a high density of PV generation, the probability of encountering a power island is small, but for the power margins originating from standard protection relay settings it may not be regarded as negligible. In order to keep the risk from islanding to maintenance operators and customers satisfactorily low, additional islanding prevention methods are necessary to detect a loss of mains in any case that is practically feasible.

Another study concluded (Verhoeven 2002):

> Balanced conditions occur very rarely for low, medium and high penetration levels of PV-systems. The probability that balanced conditions are present in the power network and that the power network is disconnected at that exact time is virtually zero. Islanding is therefore not a technical barrier for the large-scale deployment of PV system in residential areas.

As noted, some of the measures listed are predominantly for utility personnel. The measures listed may not adequately address other types of risk to the general public or to emergency response personnel, such as firefighters. The types of risk prevalent from electrical equipment due to downed conductors have existed and will likely continue to exist regardless of the presence of DERs on the circuit. Adequate consideration should be given to the types and sources of risk and to the existing strategies in place to mitigate those risks to determine if any additional mitigation is indicated or necessary. Note that the studies described are two decades old. More current treatment of this subject in a formal study has not been identified by the authors.

4.2 Equipment Protection

With regard to the specific phenomena of unintentional islanding, reclosing out of synchronism (also referred to as reclosing out of phase) is typically a major concern associated with DER deployment.[22, 23]

Many utilities use a protective device called a recloser that contains a relay-controlled switch or breaker that initially opens when a predetermined amount of current flows through the device. A simplified diagram of the circuit elements related to reclosing is shown in Figure 6. After a short preprogrammed time interval chosen to allow the fault or overload to clear, the recloser closes the breaker, thus reenergizing the downstream line segments.

[22] Note that with higher shares of DERs, there are potentially additional impacts that must be considered, such as overload-related impacts, voltage-related impacts, reverse power flow impacts, and other system protection impacts. For a summary discussion of these topics, see *High-Penetration PV Integration Handbook for Distribution Engineers*, https://www.osti.gov/biblio/1235905.

[23] Fault conditions that could cause islanding concerns for DERs are sometimes associated with concerns for the potential of transient or temporary overvoltage from DERs, such as load rejection overvoltage and ground fault overvoltage. Several studies on these topics have been published, including *Inverter Load Rejection Over-Voltage Testing*, https://www.nrel.gov/docs/fy15osti/63510.pdf, and *Inverter Ground Fault Overvoltage Testing,* https://www.nrel.gov/docs/fy15osti/64173.pdf. For a discussion on neutral grounding, the reader should also consult IEEE Std C62.92.4 - IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems—Part IV: Distribution.

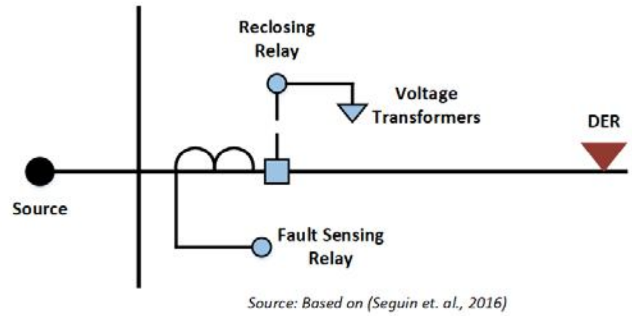


Figure 6. Simplified illustration of circuit elements related to reclosing

If the fault or overload persists longer than the time interval, the recloser again opens the switch to isolate the fault. The recloser might open and reclose several times, and if the fault is still uncleared, the recloser locks itself open for utility personnel to address the issue (Pansini 2005).

If a DER becomes islanded, the operation of utility reclosers reclosing onto an energized line could result in retripping the line or damaging connected equipment (i.e., an out-of-phase reclosure). As noted by Ingram et al. (2017):

> If an unintentional island persists after a recloser has opened, it is possible that the phase relationship of the islanded grid could deviate from that of the bulk system. The reclosing action could forcibly resynchronize the grids. The risk of this forced synchronization is potentially significant because customer equipment—motor loads, in particular—could be damaged by the possible sudden change in frequency and voltage phase [resulting in large transient torques on mechanical systems (e.g., shafts, blowers, and pumps)]. Effectively, the phase voltages experienced by the loads could jump instantaneously, stressing any machine that has a speed/position relationship to the grid frequency. Generally, the greater the phase difference between the islanded grid and the bulk system, the greater the risk of damage to these types of equipment.

The default response time for all types of DERs using all methods of unintentional islanding is 2 seconds. The response time can be extended to 5 seconds and must be agreed upon by the area EPS operator and the DER operator. Even with the shorter response duration of 2 seconds, a common concern is the coordination of fast auto-reclosures with unintentional islanding response time. Because the unintentional islanding methods are not designed to detect fault conditions, the response time is not bound by the necessary fast fault response times that fault equipment must meet.

Reclosers are a type of protective device often used by utilities to mitigate faults on the distribution system. To decrease the duration of interruptions, reclosers are often deployed with a "fast reclosing" function that reenergizes a circuit within 1 second or less after a fault condition has been detected. When a fast reclosure initially opens, motors in the system will start slowing down and can regenerate voltage on the bus. If the voltage is restored before the motors are significantly slowed down, a large torque pulse can occur on motor shaft; therefore, a concern of fast reclosures and motor reenergization exists even without the DERs in the circuit unless corrective methods are implemented. For area EPS locales that use fast reclosing, there is concern about out-of-phase reclosing, and further study might be required.

For feeders or sections of the distribution circuit where a recloser is used, a generation-to-load study might be desired to see if an island can be sustained (Ropp and Ellis 2013).

To address the concerns of out-of-phase reclosing, three solutions are typically considered: lengthening the reclosing time to more than 2 seconds, blocking the hot-line recloser, blocking the out-of-phase recloser, removing the recloser functionality, and DTT, as described in the appendix.

For circuits with enough DERs to sustain an island, hot-line recloser blocking is a functionality added to existing reclosers that delays the fast reclosing until the circuit being reclosed is measured to be de-energized. Another option is to simply disable the reclosing functionality of the protection equipment from a circuit. Reliability impacts from any of these methods should be considered when choosing a solution.

4.3 Maintaining Power Quality

Utilities are responsible for supplying power to customers and for keeping the voltage and frequency within acceptable ranges. In an islanding condition, however, a utility cannot control the voltage and frequency within the island. These parameters could drift the longer an island is sustained. DERs have trip settings for voltage and frequency. If the voltage or frequency reach the trip settings, the DERs will stop exporting power, and the island will collapse.

4.4 Impact of Grid Support and Ride-Through Functions

IEEE Std 1547-2018 requires DERs to maintain anti-islanding functionality with and without grid support functions enabled. Conversely, anti-islanding functionality may not interfere with grid support functions and the new voltage and frequency ride-through requirements for all DERs. To help enable these capabilities at the same time, DER functions and requirements are prioritized relative to each other as follows[24]:

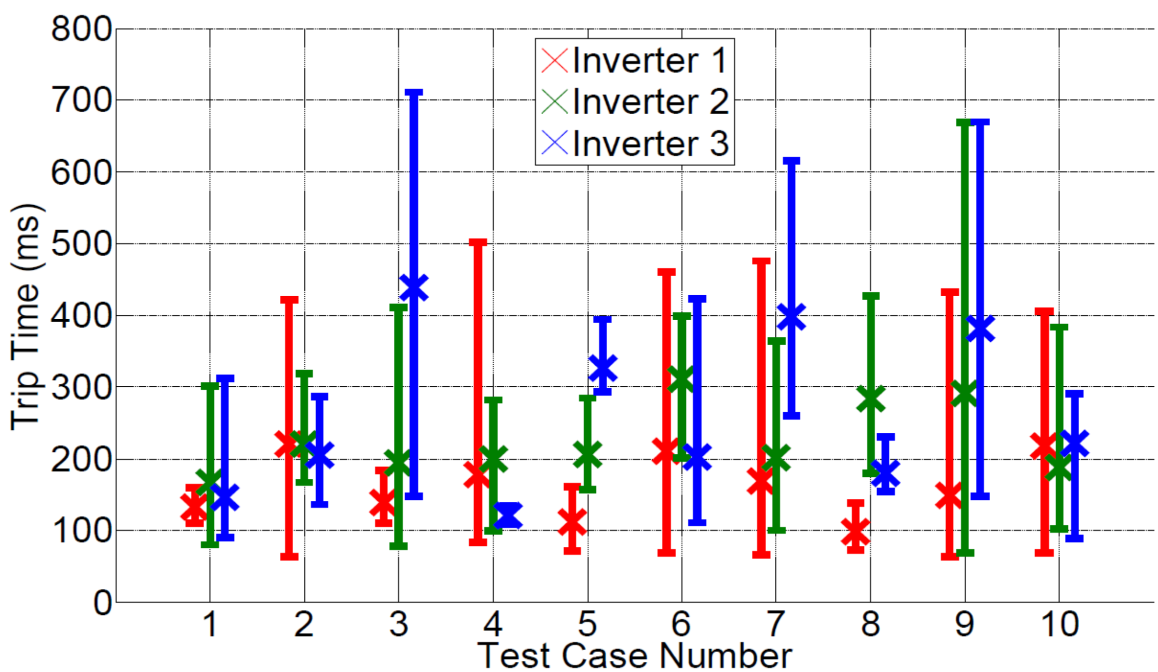
1. Response to disabling permit service setting
2. DER tripping requirements
3. Ride-through requirements (per IEEE Std 1547-2018 Clause 4.7, “Ride-through may be terminated by the detection of an unintentional island.”)
4. Voltage-active power mode requirements
5. Response to active power limit
6. Voltage regulation functions.

Several laboratory tests and some field demonstrations have been conducted to determine the functionality of grid support functions such as voltage regulation and ride-through. Some studies have also investigated the impact of grid support functions on anti-islanding performance.

[24] Some caveats exist. The reader should read IEEE Std 1547-2018 carefully to understand the prioritization of DER responses.

One team conducted a set of power-hardware-in-the-loop experiments to determine the impacts on the effectiveness of anti-islanding functions resident in PV inverters under multi-inverter deployment scenarios with grid support functions enabled. PV inverters were tested with four grid support functions enabled: voltage ride-through, frequency ride-through, volt-volt ampere reactive (VAR) control, and frequency-watt control.[25] Results were published in a report titled *Experimental Evaluation of PV Inverter Anti-Islanding with Grid Support Functions in Multi-Inverter Island Scenarios* (Hoke et al. 2016).

The team observed that for the single-inverter test case with grid support functions enabled, the maximum run-on time (duration of the island) increased slightly with voltage and frequency ride-through; however, for the 50 tests conducted on each inverter (150 total), the maximum run-on time was 711 milliseconds, significantly less than the 2-second limit currently imposed by IEEE Std 1547-2018. The test was run with the inverter regulating voltage with a steep volt-VAR curve with voltage and frequency ride-through enabled (frequency-watt was disabled). Figure 7 shows results for run-on times for three separate inverters tested under various conditions.



Source: Hoke et al. 2016

Figure 7. Run-on time test results for 3 inverters with grid support functions enabled

The team found no evidence that volt-VAR control or frequency-watt control increased maximum run-on time, confirming expectations.

[25] Note that ride-through is an inherent capability of DERs that cannot be turned off, according to IEEE Std 1547-2018.

The team also investigated the possibility of load rejection overvoltage during islanding events. Under the balanced islanding conditions used for the anti-islanding tests, the team observed no overvoltages exceeding 110% of nominal voltage, as expected.[26]

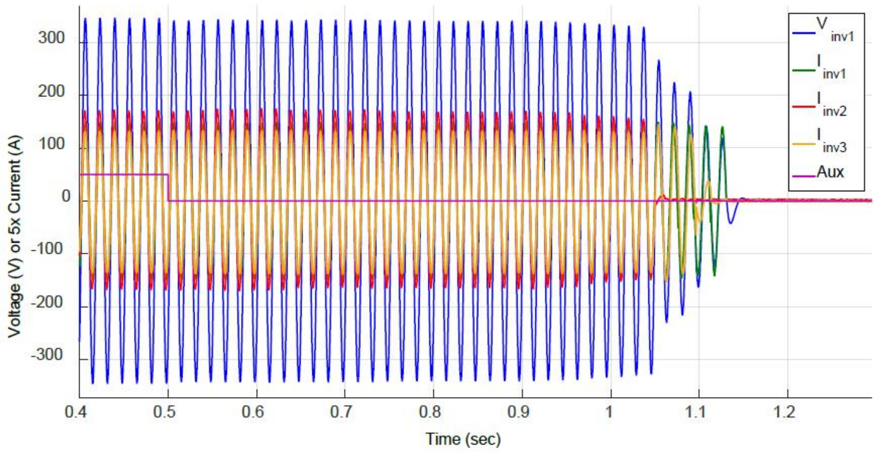
In another study, a project team from Sandia National Laboratories and Northern Plains Power Technologies conducted laboratory simulations and experiments to determine the impact of PV inverter grid support functions on various anti-islanding detection methods. Results were published in January 2019 in a report titled *Evaluation of Multi-Inverter Anti-Islanding with Grid Support and Ride-Through and Investigation of Island Detection Alternatives* (Ropp et al. 2019). This study concluded that enabling voltage regulating functions was not observed to have an adverse effect on anti-islanding performance, and in certain cases, it resulted in reduced run-on time. The team noted that the ride-through of voltage and frequency was observed to have an adverse impact on islanding detection; however, in all cases tested, run-on times remained within the 2-second requirement in IEEE Std 1547-2018. The team introduced a technique called "collaborative controls," which was shown to mitigate the negative impacts of ride-through (Ropp et al. 2019).

4.5 Multiple-Inverter and Mixed Distributed Energy Resource Scenarios

DER systems, especially inverter-based DERs, are highly configurable to fit many deployment needs at many scales—from single-inverter residential deployments to utility-scale systems with dozens of inverters. The sheer number of potential system designs, equipment, and configurations make it impossible to test every scenario; however, many teams have published results from laboratory studies.

Hoke et al. (2016) investigated the anti-islanding functionality impacts from multiple inverters with grid support functions enabled. Under the multi-inverter test case, three common, commercially available, single-phase PV inverters from three different manufacturers were simultaneously deployed at nearby points on the same simulated distribution feeder and subjected to a variety of representative island configurations. For the 244 multi-inverter tests conducted, the maximum run-on time observed was 632 milliseconds, again well within the 2-second requirement. Example test results are shown in Figure 8.

[26] More comprehensive testing of load rejection overvoltage can be found in a related report on Inverter Load Rejection Over-Voltage Testing, https://www.nrel.gov/docs/fy15osti/63510.pdf.



Source: Hoke at al. 2016

Figure 8. Example test results for a scenario with multiple inverters with grid support functions enabled

In another study, a team from Sandia National Laboratories and Northern Plains Power Technologies conducted a set of computer simulations to determine the performance of inverter-based anti-islanding under scenarios with combinations of different inverters using different types of islanding detection methods and combinations of inverters and synchronous generators. The simulations were conducted with and without voltage and frequency ride-through enabled, and the island run-on times of various anti-islanding methods were analyzed. Results were published in July 2018 in a report titled *Unintentional Islanding Detection Performance with Mixed DER Types* (Ropp et al. 2018).

The team noted—as expected per results from other studies—that simulation results showed that the addition of ride-through degrades the performance of anti-islanding detection methods.

Under the mixed-inverter test conditions, some combinations of methods resulted in larger non-detection zones and longer island run-on times (some exceeding 2 seconds), whereas other combinations remained highly effective over a wide range of conditions.

For the methods studied, the team observed that islanding detection methods vary greatly in their effectiveness depending on the types of DERs in the island. The team noted that, in general, mixed-type DER scenarios (inverter and synchronous generators) increased run-on times and had larger non-detection zones; however, in some cases, anti-islanding performance *improved*.

4.6 Locales with High Shares of Distributed Energy Resources

A handful of locations already experience high shares of DERs; however, in most locales, this is currently not an issue. High shares of DERs create concerns for the area EPS operator because of the large number of devices on the feeder and the different types of unintentional islanding methods employed. Public utility commissions in several states have started research projects and study groups[27] to discuss these topics.

One report, completed in 2016 for the California Public Utilities Commission, noted that to adequately assess the risk from unintentional islanding, consideration must be given to not only the DER but also the load composition[28] in the potential island (Bebic, Sun, and Marin 2016). Under the project, islanding tests were performed on groups of physical inverters. The inverters were set to unity power factor with no advanced functions enabled. Under the test conditions, the team noted that the pre-islanding power factor of the circuit had a strong impact on the duration of the islanding. The team also noted that increased motor loads also had an impact on islanding duration.

[27] For example, the California Public Utilities Commission Interconnection Rulemaking Working Groups convened under the R.17-07-007 docket. Working Group Four investigated anti-islanding conditions and made recommendations in a final report published in August 2020. Proceedings under Working Group Four are available at https://gridworks.org/initiatives/rule-21-working-group-4/. The final report is available at https://gridworks.org/wp-content/uploads/2020/08/R21-WG4-Final-Report.pdf.

[28] The report follows the Western Electricity Coordinating Council recommendations to represent utility loads based on equipment varieties that include motor loads, power electronic loads, resistive loads, and constant current loads (Bebic, Sun, and Marin 2016).

5 Guidelines to Determine the Risk of Unintentional Islanding

DER deployments include scenarios that could present challenges for onboard anti-islanding techniques. There are no formal standards for assessing the risk of unintentional islanding; however, Ropp and Ellis, in a report published by Sandia National laboratories in 2012 and revised in 2013, provided recommendations. To date, these guidelines have been widely used in interconnection studies to evaluate the risks of unintentional islanding for specific installations and to help determine the appropriate mitigation for those risks. The content focuses on PV systems, but it could be applied to any DER.

The guidelines note a set of scenarios in which unintentional islanding is considered impossible. These include the following (Ropp and Ellis 2013):

- Load exceeds DER capacity. A sustained island is impossible if the aggregated nameplate AC rating of all DERs within the potential island is less than the minimum real power load within the island. Because the load exceeds what the DER can support by itself, the load will quickly reduce the voltage to less than the programmed low-voltage threshold in the DERs if an island forms.
- Reactive power supply and demand cannot be maintained. This relies on the principle that for an island to be sustained, both the active and reactive demand within the island must be supplied by the DERs. All loads with motors require reactive power. In scenarios where the inverter is operating at unity power factor, with negligible reactive power contribution, reactive power is supplied by the source at the substation or capacitor banks along the distribution line. Situations when the inverter is regulating its VAR supply, however, might require further study. Note that in an inverter-based island, volt-VAR control ceases to stabilize voltage, so it does not increase the islanding risk.
- External supplemental mechanisms are used. Examples of external supplemental mechanisms for anti-islanding protection include communications-based methods, such as DTT, power line carrier permissive signal, and supervisory control and data acquisition systems.

Ropp and Ellis (2013) also noted that several scenarios could present challenges to current built-in anti-islanding methods. These include the following:

- The potential island contains large capacitors and is operating near unity power factor (within 1%). Note, however, that this relies on knowledge of what method of anti-islanding detection the PV inverters are using. The study is relevant only if all inverters are using positive feedback on frequency.
- High-penetration scenarios. Studies have shown that the speed of anti-islanding detection could decrease as the number of inverters in the island increases; however, there are variations in effectiveness—for example, anti-islanding detection speed could be maintained if all the inverters use positive feedback and the interconnecting impedances between inverters is low. An example of this type of deployment is given as a commercial installation on a common distribution transformer.

- Deployments with different types of PV inverters. Studies have shown that deployments with PV inverters with different manufacturers degrade anti-islanding detection performance. (Note that these guidelines were written in 2012 and updated in 2013. Additional studies have been done since then to further investigate this. See Section 4.5 of this document for the related discussion under multiple-inverter scenarios.)
- Deployments with both PV inverters and rotating generators. The anti-islanding mechanisms in these could interfere with each other enough to degrade the performance of the anti-islanding detection in both types of generators.

Considering these elements, Ropp and Ellis (2013) suggested a four-step process for assessing unintentional islanding risk. This process is summarized in the flowchart in Figure 9.

If the screening shows there could be a risk of unintentional islanding, additional study should be performed. Additional study could involve more detailed modeling of the distribution circuit equipment, DER, loads, and area EPS protection schemes.[29]

Depending on the results of the detailed study,[30] mitigation by supplemental means of anti-islanding protection may be needed.

Given the new requirements specified in IEEE Std 1547-2018, there is renewed discussion on whether and how these guidelines should be updated or whether new tools may be necessary to effectively screen for risk of islanding.

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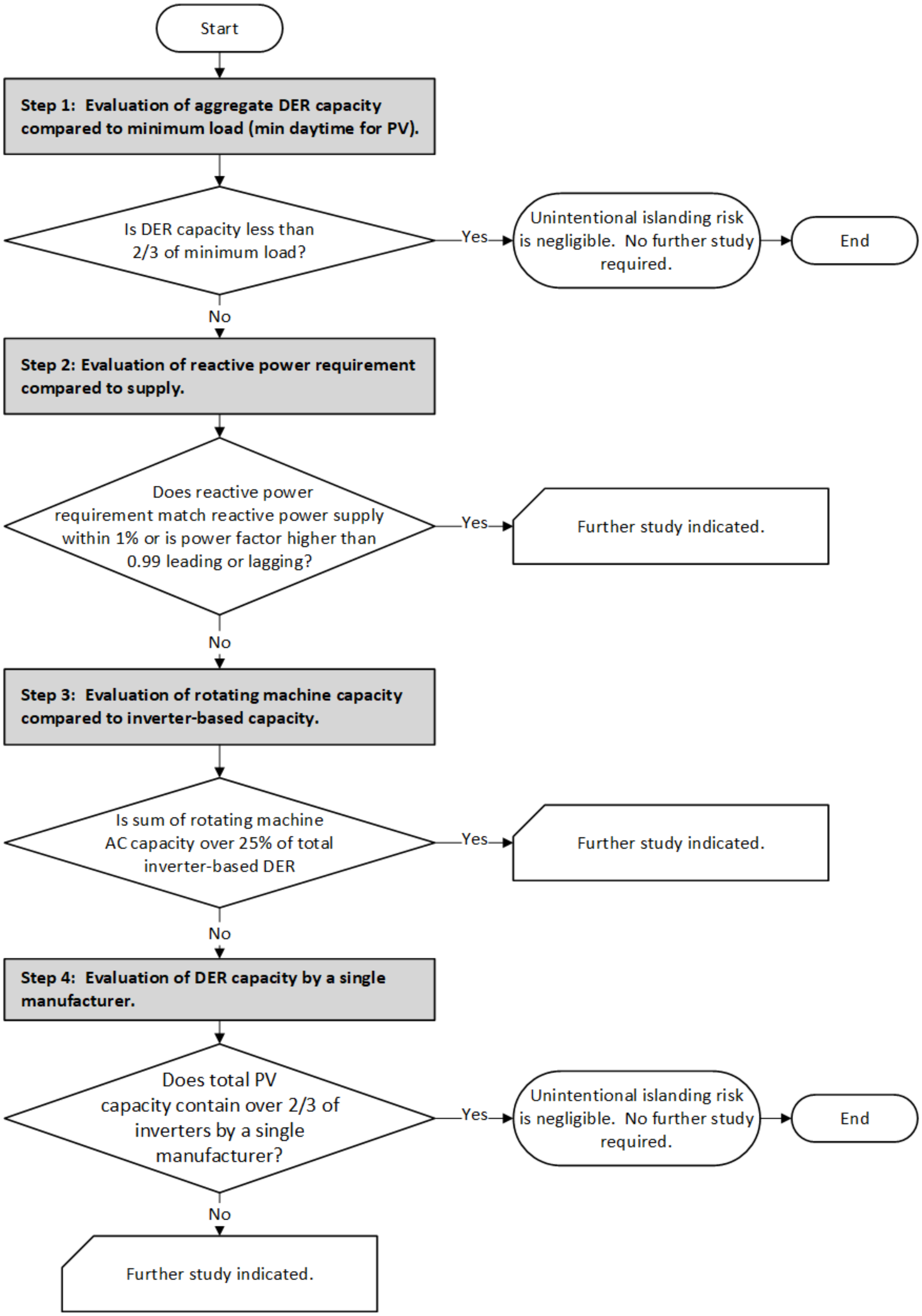
[29] For a detailed discussion of the topic, see IEEE Std 1547.7 Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection.

[30] See the National Rural Electric Cooperative Association's *PV System Impact Guide* for examples of PV interconnection impact studies, including risk of islanding screening, https://www.cooperative.com/programs-services/bts/Documents/SUNDA/NRECA%20-%20SUNDA%20Impact%20Guide-v3%20final.pdf.



Source: Based on procedure described in Ropp and Ellis 2013

Figure 9. Procedure for assessing risk of unintentional islanding

6 Conclusion

As noted, topics related to unintentional islanding risk and prevention have been and continue to be of concern and thus the topic of continued research and discussion. Recent activities under the California Public Utilities Commission Interconnection Rulemaking (R.17-07-007, “Rule 21”) are an example. Under these activities, California utilities, developers, the utility commission, and other stakeholders have determined that a formal working group is needed to discuss the topic in more detail.[31]

Discussions in other jurisdictions related to unintentional islanding will likely happen as updates are made to interconnection requirements to reflect the latest revision of IEEE Std 1547-2018.

[31] See the California Public Utilities Commission Rulemaking 17-07-007: Decision Addressing Remaining Phase I Issues (page 90) for more discussion: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M387/K064/387064665.PDF.

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Appendix: Summary of Supplementary Anti-Islanding Protection Methods[32]

Due to equipment and personnel safety dimensions, some jurisdictions apply additional methods to ensure that distributed energy resources (DERs) do not island. This appendix summarizes these concerns and supplementary anti-islanding protection strategies.

Many methods can be used to protect against unintentional islands. Some commonly used methods include protective relays for the detection of over-/underfrequency or over-/undervoltage, reverse power detection, or minimum import/export relays, impedance insertion, power line carrier communications, and direct transfer trip (DTT) (Kroposki 2016; Bower and Ropp 2002).

Direct Transfer Trip

DTT is one of several schemes used to avoid sustained unintentional islanding. DTT uses a communications signal from an area electric power system (EPS) component, such as a feeder breaker or an automatic line-sectionalizing device, to command the DER to disconnect from the circuit. DTT could also be implemented with the addition of sync-check relaying or undervoltage-permissive relaying at the feeder breaker or automatic line-sectionalizing devices to maintain coordination with protection schemes. DTT might require communications from not only the substation breaker but also any automatic line-sectionalizing devices upstream from the DERs.

Several options for DTT communications are available. Utilities will typically specify their preferred method,[33] which could include:

- Direct fiber to substation with proper interface provisioning
- Licensed microwave with proper interface provisioning
- Class A DS0, 4-wire, leased line provisions by local exchange carrier
- Telecommunications options via Class B, T1 lease options.

DTT can also eliminate out-of-phase reclosing concerns because the recloser action can be coordinated with tripping schemes to ensure that no unintentional islands are formed.

Even with DTT, depending on the latency of the trip signal, fast reclosing schemes might need to be reviewed and either slowed down to guarantee that the DER stops generating prior to the first reclosing action or otherwise modified to maintain protective coordination.

DTT is generally considered only for large DER installations because of its high cost to implement. Costs vary among locations. One report done by the California Rule 21 Working Group Four for the California market notes (California Public Utilities Commission 2020):

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[32] Note that some of these methods will achieve only partial compliance with the IEEE Std 1547-2018 requirements.
[33] For an example, see the Pacific Gas and Electric Company's (PG&E's) *Transmission Interconnection Handbook*, noted in this document's references.

The cost of installing DTT is significant and, in some cases, the single largest cost of new machine generation projects. PG&E's Unit Cost Guide states that the base cost of a single DTT scheme, including paired transmitter and receiver, is $600,000, and the base cost of a recloser is $80,000. 12 Multiple DTT units can be required, increasing the base cost accordingly. If related costs, such as Cost of Ownership (COO) and Income Tax Component of Contribution (ITCC) are included, the all-inclusive cost to the developer for DTT and reclosers is roughly double the base cost. The costs of DTT can exceed the cost of the generator itself, in all cases becoming a substantial part of overall costs, and can affect project viability. Other related costs such as leased line communications infrastructure can be particularly expensive in less-urban areas. The costs of DTT are particularly relevant in more rural areas of the state where the grid is radial and DTT is applied to numerous substations.

These upgrades frequently force renewable DER projects to withdraw interconnection applications due to their high interconnection costs and/or long implementation timelines. Installation of DTT can take up to 18-24 months to complete. Installation of a recloser can take up to 6-12 months to complete.

Supplemental Over-/Underfrequency or Over-/Undervoltage Protective Relays

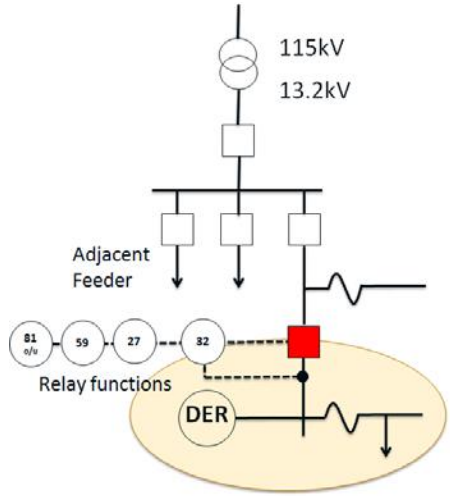
Supplemental protective relays are typically installed by electric utilities on larger DER systems, regardless of similar relaying and protection functions residing withing the DER system. Over-/undervoltage and frequency trip settings are programmed into the relays. If the relay detects these parameters outside the acceptable window, the relay trips and causes the DER to shut down.

Reverse Power or Minimum Import/Export Relays

Reverse power or minimum import/export relays are passive anti-islanding techniques. These methods add overvoltage/undervoltage and over-/underfrequency trip settings implemented through relay functions (57/27, 81/81[34]). These settings define an acceptable range of voltage and frequency limits. If the measured conditions are outside of this range, the DERs trip offline.

If supplemental anti-islanding protection is required, this approach is often used when DERs are not expected to export power to the grid (e.g., when local loads are larger than the DERs, and all generated power is consumed on-site). In these cases, an additional protective relay function (Function 32: reverse power) is added to the site relay scheme to disconnect the DERs if the relay senses that they are exporting power, as shown in Figure A-1 (Kroposki 2016).

[34] IEEE Std C37.2 defines relay device functions as follows: Device number 59 is for overvoltage relay, device number 27 is for undervoltage; and device numbers 81 and 81 are for overfrequency and underfrequency, respectively (IEEE 2008).



Source: Kroposki 2016

Figure A-1. Relay functions

Reverse or minimum import active power unintentional islanding protection provides full conformance if all tests are satisfactorily met. Note: The reverse or minimum import active power flow protection device is sensed between the point of DER connection or the point of common coupling and will disconnect or isolate the DERs if the power flow falls to less than a set threshold or reverses. For multiphase devices, tests are conducted on each phase and all phases simultaneously. For DERs having a range of adjustable minimum import active power settings, the tests are to be repeated for the minimum and maximum import active power settings.

IEEE Std 1547.1-2020 Clause 5.10.5 provides information on testing reverse or minimum import active power flow functionality.

Permissive Hardware Input

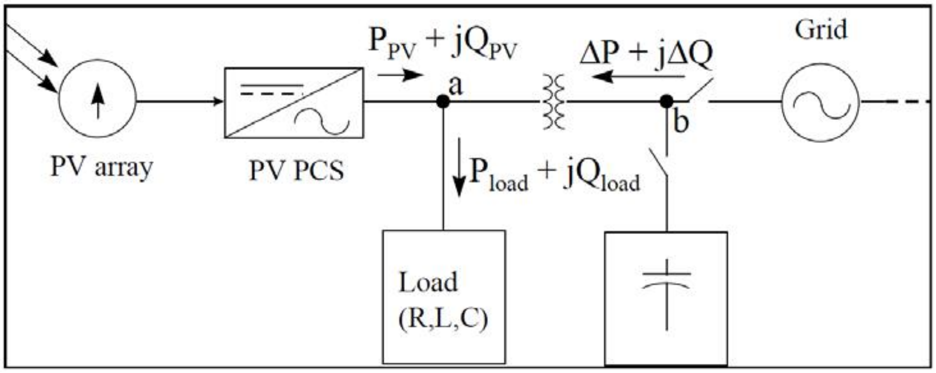
This method uses DERs fitted with hardware that responds to an unintentional islanding condition by ceasing to energize within the required response time of 2 seconds or other mutually agreed-upon response time. Examples of the types of hardware that can be used are contact closure, a transistor-transistor logic signal, or other hardware means. An example of the signal could be DTT.

Note that this is separate from the permit service function.

The hardware input test, described in IEEE Std 1547.1-2020 Clause 5.10.4, does not require balanced resistive-inductive-capacitive loads or a contactor to remove the utility and island the DER. It does require the monitoring of the permissive and nonpermissive state and a method to trigger data capture to determine the response times.

Impedance Insertion

This method requires the installation of a low-value-impedance device on the utility side of a distribution transformer. Figure A-2 shows the addition of a capacitor bank (connected at point *b*). Under this method, if the circuit on the left side of the switch at point b were to become islanded, the capacitor bank is commanded to close after a short delay. The addition of the capacitor bank functions to disrupt the balance of generation to load in the island (Bower and Ropp 2002).



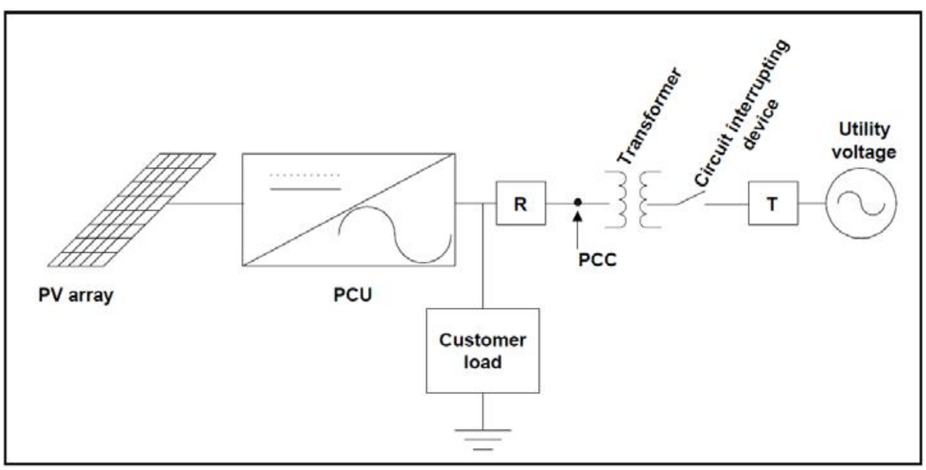
Source: Bower and Ropp 2002

Figure A-2. One-line diagram of the impedance insertion method using a capacitor bank

Power Line-Conducted Permissive Signal Testing

This method of anti-islanding protection relies on a signal conducted on the distribution primary line. DERs designed for this type of unintentional islanding method will have a receiver that monitors the presence of the permissive signal, and upon the loss of signal, the DER must cease to energize and trip within 2 seconds.

A one-line diagram of the concept is presented in Figure A-3. In the figure, the box labeled "T" transmits a signal to the receiver, marked "R." As long as the signal is present, the DER has permission to operate. If the signal is discontinued, the circuit-interrupting device disconnects the DER within the required time.



Source: Bower and Ropp 2002

Figure A-3. One-line diagram of power line carrier communications method

Because the power line-conducted permissive signal unintentional islanding method requires the transmission of the permissive signal, only partial compliance is granted when successfully detecting the absence of the permissive signal and ceasing to energize within the required response time. The absence of a permissive signal on all phases of a DER is indicative of the loss of continuity of the power line and represents an islanded situation, so upon loss of the permissive signal, the DER must cease to energize and trip.

The laboratory test procedure in IEEE Std 1547.1-2020 Clause 5.10.3 requires an attenuation of the signal to evaluate the signal strength requirements. Note that the power connection is never interrupted—only the permissive signal path is interrupted or attenuated; therefore, there is no need for load banks, a test matrix, or a need to isolate generation with load.

Note that in this method, if there is a loss of the permissive signal for any reason, there is no provision to allow the DER to reenergize the area EPS after it has tripped. This contrasts with onboard methods that reenergize after the required time delay after a trip has lapsed and the voltage and frequency at the point of DER connection is within operating ranges. The DER can reenergize the area EPS only if the permissive signal is present.

Ongoing Research on Additional Methods of Islanding Detection

Efforts have been ongoing to develop new methods of unintentional islanding detection and mitigation that adequately address future concerns. These methods include islanding detection based on synchrophasors and centralized islanding detection (inter-tripping schemes) (Etxegarai, Eguía, and Zamora 2011).

Phasor Measurement Unit-Based Islanding Detection

This method uses two phasor measurement units: one located at the grid side and one at the DER. If the signals from the two units are not comparable within certain parameters, a circuit breaker is tripped to turn off the DER (Etxegarai, Eguía, and Zamora 2011).

Centralized Detection of Unintentional Islanding

Centralized detection of unintentional islanding is based on the use of a central controller connected to all the circuit breakers and all the individual DERs in the circuit via an Ethernet link. The central controller hosts an islanding detection algorithm that monitors the circuit. If an island is detected, the central controller sends tripping commands to the DERs.

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IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

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Abstract: The technical specifications for, and testing of, the interconnection and interoperability between utility electric power systems (EPSs) and distributed energy resources (DERs) are the focus of this standard. It provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. It also includes general requirements, response to abnormal conditions, power quality, islanding, and test specifications and requirements for design, production, installation evaluation, commissioning, and periodic tests. The stated requirements are universally needed for interconnection of DER, including synchronous machines, induction machines, or power inverters/converters and will be sufficient for most installations. The criteria and requirements are applicable to all DER technologies interconnected to EPSs at typical primary and/or secondary distribution voltages. Installation of DER on radial primary and secondary distribution systems is the main emphasis of this document, although installation of DERs on primary and secondary network distribution systems is considered. This standard is written considering that the DER is a 60 Hz source.

Keywords: certification, clearing time, codes, commissioning, communications, dc injection, design, diesel generators, dispersed generation, distributed generation, electric distribution systems, electric power systems, energy resources, energy storage, faults, field, flicker, frequency support, fuel cells, generators, grid, grid support, harmonics, IEEE 1547™, induction machines, installation, interconnection requirements and specifications, interoperability, inverters, islanding, microturbines, monitoring and control, networks, paralleling, performance, photovoltaic power systems, point of common coupling, power converters, production tests, quality, power, protection functions, public utility commissions, reclosing coordination, regulations, ride through, rule-making, standards, storage, synchronous machines, testing, trip setting, utilities, voltage regulation, wind energy systems

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Introduction

This introduction is not part of IEEE Std 1547™-2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces.

IEEE Std 1547 was the first of a series of standards developed by Standards Coordinating Committee 21 on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage (SCC21) concerning distributed resources interconnection. IEEE Std 1547 was amended in 2014 (IEEE Std 1547a™-2014) in response to a widely expressed need to make changes to subclauses related to voltage regulation, voltage response to Area EPS abnormal conditions, and frequency response to Area EPS abnormal conditions in IEEE Std 1547-2003. The additional documents in that series are as follows:

— IEEE Std 1547.1™ [B17] provides conformance test procedures for equipment interconnecting distributed energy resources (DER) with electric power systems (EPS).[1]

— IEEE Std 1547.2™ [B18] is an application guide for IEEE Std 1547.

— IEEE Std 1547.3™ [B19] provides guidance for monitoring, information exchange, and control of DER interconnected with EPS.

— IEEE Std 1547.4™ [B20] provides guidance for design, operation, and integration of distributed resource island systems with EPS.

— IEEE Std 1547.6™ [B21] is a recommended practice for interconnecting DER with electric distribution secondary networks.

— IEEE Std 1547.7™ [B22] provides guidance for conducting distribution impact studies for DER interconnection.

The first publication of IEEE Std 1547 was an outgrowth of the changes in the environment for production and delivery of electricity and built on prior IEEE recommended practices and guidelines developed by SCC21 (which included IEEE Std 929™-2000 [B14] and IEEE Std 1001™-1988 [B15]).

Traditionally, utility EPSs were not designed to accommodate active generation and storage at the distribution level. The technologies and operational concepts to effectively integrate DERs into existing EPSs continue to be further developed to realize additional benefits and to avoid negative impacts on system reliability and safety.

There is a critical need to have a single document of consensus standard technical requirements for DER interconnection rather than having to conform to numerous local practices and guidelines. This standard addresses that critical need by providing uniform criteria and requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection.

The intent of this standard is to define the technical requirements in a manner that can be universally adopted. The universality relates not only to the technical aspects, but also to the adoption of this standard as being pertinent across a number of industries and institutions, e.g., hardware manufacturers, utilities, energy service companies, codes and standards organizations, regulators and legislators, and other interested entities.

This standard focuses on the technical specifications for, and testing of, the interconnection itself, and not on the types of the DER technologies. This standard aims to be technology-neutral, although acknowledges that the technical attributes of DER and the types and characteristics of EPSs do have a bearing on the interconnection requirements. The addition of a DER to an EPS will change the system and its response in some manner. Although this standard establishes criteria and requirements for interconnection, this

[1] The numbers in brackets correspond to the numbers of the bibliography in Annex A.

standard is not a design handbook nor is it an application guideline. This standard provides the minimum functional technical requirements that are universally needed to help assure a technically sound interconnection. Any additional local requirements should not be implemented to the detriment of the functional technical objectives of this standard.

This standard recognizes that distributed energy resources need to be integrated into the Area EPS in coordination with the Area EPS operator. The functions specified in this standard may need to be supplemented in coordination with the Area EPS operator for specific situations.

It is beyond the scope of this standard to address the methods used for performing EPS impact studies, mitigating limitations of the Area EPS, or addressing the business or tariff issues associated with interconnection.

Contents

IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

1. Overview

1.1 General

This standard provides interconnection and interoperability technical and test specifications and requirements for distributed energy resources (DERs). Additionally, several annexes are included in this standard that provide additional material for informative purposes, but are not required to be used in conjunction with this standard.

1.2 Scope

This standard establishes criteria and requirements for interconnection of distributed energy resources with electric power systems (EPSs) and associated interfaces. The stated technical specifications and requirements are universally needed for interconnection and interoperability of distributed energy resources (DERs)[2] and will be sufficient for most installations.[3] The specified performance requirements apply at the time of interconnection and as long as the DER remains in service.

[2]For example, synchronous machines, induction machines, or static power inverters/converters.
[3]Additional technical requirements may be necessary for higher DER penetration situations.

1.3 Purpose

This document provides a uniform standard for the interconnection and interoperability of distributed energy resources with electric power systems. It provides requirements relevant to the interconnection and interoperability performance, operation and testing, and, to safety, maintenance and security considerations.

1.4 General remarks and limitations

The criteria and requirements in this document are applicable to all distributed energy resource technologies interconnected to EPSs at typical primary or secondary distribution voltage levels. Installation of DER on radial primary and secondary distribution systems is the main emphasis of this standard, although installation of DER on primary and secondary network distribution systems is considered. This standard has been written assuming a 60 Hz nominal system frequency.[4]

Figure 1 illustrates the scope of this standard. The criteria and requirements in this document may influence the design and capabilities of the power interface, the *local DER communication interface* and all those parts of a DER that are related to meeting the requirements of this standard. In Clause 4 to Clause 11, the term "DER" refers to all those parts of a DER that are related to meeting the interconnection and interoperability requirements of this standard.

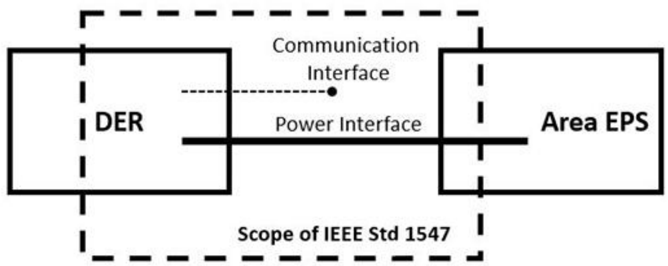


Figure 1 —Scope of this standard

The following list describes what remains outside the scope of this standard:

— This standard as a whole is not intended for, and is in part inappropriate for, application to energy resources connected to transmission or networked sub-transmission systems.[5, 6]

— This standard does not define the maximum DER capacity for a particular installation that may be interconnected to a single point of common coupling (PCC) or connected to a given feeder.

— Outside of the specific interconnection and interoperability requirements in the following clauses, this standard does not prescribe DER self-protection or any DER operating requirements, as long as these do not preclude the DER from meeting the requirements of this standard.[7]

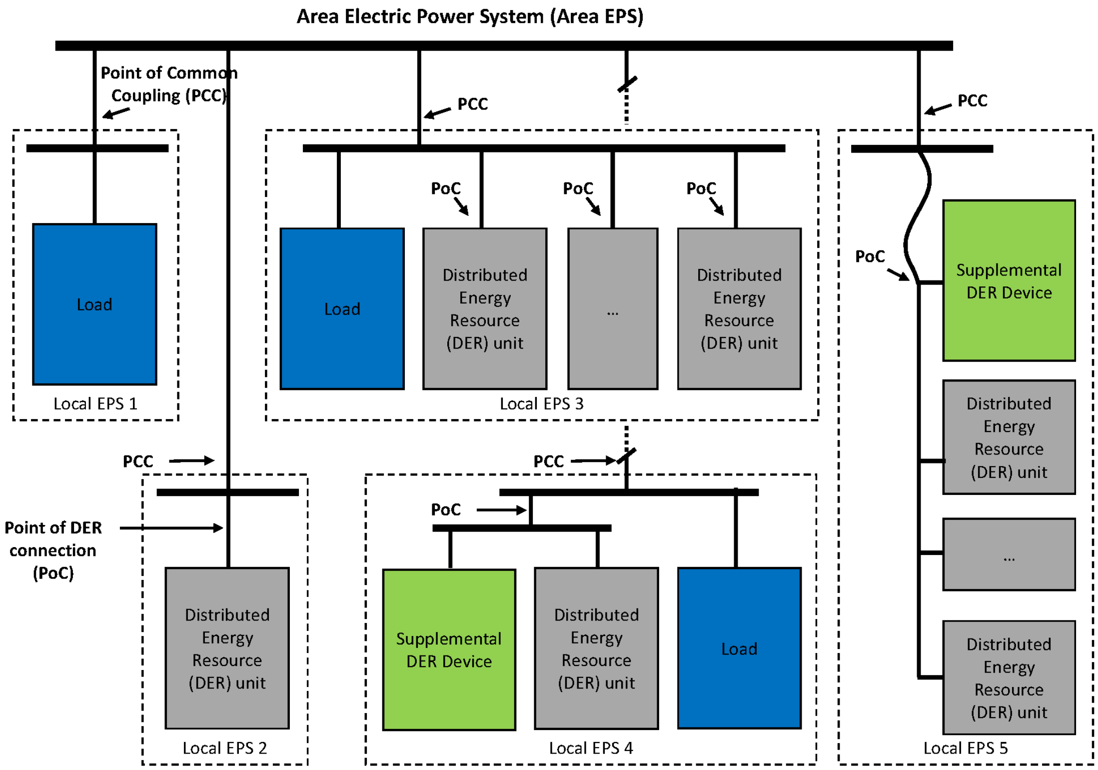
— This standard does not address planning, designing, operating, or maintaining the Area EPS with DER.

[4]If the standard is used with other nominal frequency values, all frequency values in the standard should be adjusted appropriately. This may require proportional adjustment of the frequency values in coordination with the *regional reliability coordinator*.
[5]Investigations of events that inadvertently tripped *bulk power system* connected resources in North America suggest that one root cause may have been misapplication of previous versions of this standard; refer to NERC [B28] for more details.
[6]The performance of energy resources connected to transmission or networked sub-transmission systems may be specified by the responsible transmission planner in coordination with the *regional reliability coordinator*.
[7]Requirements specified in 6.4.2 and 6.5.2 do provide constraints that must be respected in the application of DER self-protection.

- This standard does not apply to automatic transfer schemes in which load is transferred between the DER and the EPS in a momentary make-before-break operation provided the duration of paralleling the sources is less than 100 ms, except as noted in Clause 9.
- As defined in 4.13, 5.3.1, 6.4.2.1, 6.5.2.1, and 10.1, emergency and standby DER[8] are exempt from certain requirements of this standard.
- This standard does not give any guidance regarding how the Area EPS operator may specify functional parameter settings other than the default setting within the specified *ranges of allowable settings*, e.g., to coordinate with the existing Area EPS protection and control devices.
- This standard does not determine the communication network specifics nor the utilization of the DER provisions for a local DER interface capable of communicating (*local DER communication interface*) to support the information exchange requirements specified in this standard.
- The lower and upper values of the *ranges of allowable settings* for voltage and frequency trip settings specified in this standard for DER are not intended to limit the capabilities and settings of other equipment on the Area EPS.[9]
- For DER interconnections that include individual synchronous generator units rated 10 MVA and greater, and where the requirements of this standard conflict with the requirements of IEEE Std C50.12 or IEEE Std C50.13, the requirements of IEEE Std C50.12 or IEEE Std C50.13, as relevant to the type of synchronous generator used, shall prevail.

This standard applies to interconnection based on the aggregate nameplate rating of all the DER units that are within the Local EPS. Supplemental DER devices other than DER units may be used to achieve compliance with the requirements of this standard at the applicable reference point per Clause 4. These devices are not required to be co-located with the DER units, but shall be within the Local EPS. The requirements of this standard shall be met regardless of the location of the DER and supplemental DER devices within the Local EPS. These relationships are shown in Figure 2.

[8]As defined by authority having jurisdiction.
[9]Refer to footnotes 80 and 99 on recommendations for utility practices to use trip settings on Area EPS equipment that conflict with this standard to occasionally and selectively accommodate worker safety practices or to safeguard distribution infrastructure while in an abnormal configuration.



NOTE 1—The example of Local EPS 1 includes only load. Any requirements for this Local EPS are outside the scope of this standard.

NOTE 2—The example of Local EPS 2 includes only DER. Depending on the DER rating, requirements of this standard apply either at the PCC or the PoC. The DER unit in this example is able to meet requirements at its terminals without any supplemental DER device; the PoC coincides with the DER unit's terminals.

NOTE 3—The example of Local EPS 3 includes both DER units and load. Depending on the aggregate DER units' rating and the percent of average load demand, requirements of this standard apply either at the PCC or the PoC. The two (or more) DER units are able to meet requirements at its terminals without any supplemental DER device; the PoC coincides with the DER units' terminals; there are two (or more) PoCs.

NOTE 4—The example of Local EPS 4 includes a DER unit, a supplemental DER device, and load. Depending on the DER unit's rating and the percent of average load demand, requirements of this standard apply either at the PCC or the PoC. The DER unit is not able to meet requirements at its terminals without any supplemental DER device; the PoC is the point where the requirements of this standard are met by the DER unit in conjunction with the supplemental DER device exclusive of any load, if present, in the respective part of the Local EPS.

NOTE 5—The example of Local EPS 5 includes two (or more) DER units and a supplemental DER device but no load. Depending on the aggregate DER units' rating, requirements of this standard apply either at the PCC or the PoC. As indicated by the curved line, the PCC and PoC may be located well apart from each other. The two (or more) DER units are not able to meet requirements at their terminals without any supplemental DER device; the PoC is the point where the requirements of this standard are met by two (or more) DER units in conjunction with the supplemental DER device exclusive of any load, if present, in the respective part of the Local EPS.

Figure 2 —Relationship of interconnection terms

The stated technical specifications and requirements are universally needed for interconnection and interoperability of DER[10] and will be sufficient for most installations.[11] The applicability of certain specifications and requirements are dependent on application considerations. For these, the requirements are provided in terms of a limited number of technology-neutral performance categories, for which it is the responsibility of the *authority governing interconnection requirements* (AGIR) to determine applicability. The rationale used as the basis for the performance categories is as follows:

For categories related to reactive power capability and voltage regulation performance requirements (Clause 5):

— Category A covers minimum performance capabilities needed for Area EPS voltage regulation and are reasonably attainable by all DER technologies as of the publication of this standard. This level of performance is deemed adequate for applications where the DER penetration in the distribution system is lower,[12] and where the overall DER power output is not subject to frequent large variations.

— Category B covers all requirements within Category A and specifies supplemental capabilities needed to adequately integrate DERs in local Area EPSs where the aggregated DER penetration is higher or where the overall DER power output is subject to frequent large variations.

For categories related to response to Area EPS abnormal conditions (Clause 6):

— *Abnormal operating performance Category* I is based on essential *bulk power system* (BPS) stability/reliability needs and reasonably attainable by all DER technologies that are in common usage today.

— *Abnormal operating performance Category* II covers all BPS stability/reliability needs and is coordinated with existing reliability standards[13] to avoid tripping for a wider range of disturbances of concern to BPS stability.[14]

— *Abnormal operating performance Category* III is based on both BPS stability/reliability and distribution system reliability/power quality needs and is coordinated with existing interconnection requirements for very high DER penetration.[15]

All performance categories specify minimum equipment capability requirements and may also specify designated limiting requirements for *ranges of allowable settings* of control or trip parameter values. For categories related to reactive power capability and voltage regulation performance requirements (Clause 5), Category B is inherently capable of meeting the requirements for Category A. For categories related to response to Area EPS abnormal conditions (Clause 6), categories with higher number values are inherently capable of meeting the voltage and frequency ride-through requirements of lower number value categories; however, this may not hold for voltage and frequency trip requirements because their *ranges of allowable settings* may be mutually exclusive. If a DER listed for a higher level *abnormal operating performance category* was used in a lower-level category application, the correct *range of allowable settings* for magnitude and duration values of trip settings shall be ensured, for example by the use of software profiles designated for each *abnormal operating performance category*.

[10]For example, synchronous machines, induction machines, or static power inverters/converters.
[11]Additional technical requirements may be necessary for some limited situations.
[12]This clause intentionally uses qualitative DER penetration levels qualifiers. The impact of DER on frequency and voltage performance of the interconnections and the regional power systems differs significantly and it remains in the responsibility of an AGIR to quantify impactful DER penetration levels. Refer to Annex B for more rationale on category assignments.
[13]In North America, the limitations for transmission-connected resources as specified in NERC PRC-024-2 [B27] may be used for reference.
[14]Includes 1LG stuck breaker transmission faults as well as normally and delayed cleared faults at the lower-level transmission and sub-transmission levels where fault durations can be longer (primarily due to the use of zone impedance relaying), e.g., sub-transmission 3LG with normal fault clearing or simultaneous 1LG faults on different phases of two sub-transmission circuits on the same structure with normal fault clearing. (NERC [B26], [B28], [B29], [B30].)
[15]For example, CA Rule 21 [B4].

Additional guidelines on criteria for assignment of DER performance categories are given in Annex B.[16]

Where applicable, the stated technical specifications and requirements are given in generator sign convention, which is opposite to load sign convention. In generator sign convention, a DER current lagging voltage provides/injects reactive power to the system (over-excited operation of DER, positive reactive power), and this tends to increase the applicable voltage under normal system conditions; a DER current leading voltage consumes/absorbs reactive power from the system (under-excited operation of DER, negative reactive power), and this tends to decrease of the applicable voltage under normal system conditions.

1.5 Conventions for word usage and notes to text, tables and figures

In this document, the word *shall* is used to indicate a mandatory requirement. The word *should* is used to indicate a recommendation. The word *may* is used to indicate a permissible action. The word *can* is used for statements of possibility and capability.

Notes to text, tables, and figures are for information only and do not contain requirements needed to implement the standard.

2. Normative references

The following referenced documents are indispensable for the application of this document (i.e., they shall be understood and used, so each referenced document is cited in text and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

ANSI C84.1, Electric Power Systems and Equipment—Voltage Ratings (60 Hz).[17]

IEC/TR 61000-3-7, Electromagnetic compatibility (EMC)—Part 3-7: Limits—Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems.[18]

IEC 61000-4-3, Electromagnetic compatibility (EMC)—Part 4-3: Testing and measurement techniques—Radiated, radio-frequency, electromagnetic field immunity test.

IEC 61000-4-5, Electromagnetic compatibility (EMC)—Part 4-5: Testing and measurement techniques—Surge immunity test.

IEEE Std 519™, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems.[19, 20]

IEEE Std 1453™, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems.

IEEE Std 1815™, IEEE Standard for Electric Power Systems Communications-Distributed Network Protocol (DNP3).

[16]As proposed in the IEEE P1547 response to FERC NOPR RM16-8 submitted by the IEEE Standards Association in May 2016 [B6], the criteria for assignment of DER performance categories outlined in the informative Annex B may be used as a reference point to partly specify "Good Utility Practice" for specific ride through requirements as required from small generating facilities per FERC Order 828 [B7].
[17]ANSI publications are available the American National Standards Institute (http://www.ansi.org/).
[18]IEC publications are available from the International Electrotechnical Commission (http://www.iec.ch) and the American National Standards Institute (http://www.ansi.org/).
[19]The IEEE standards or products referred to in Clause 2 are trademarks owned by The Institute of Electrical and Electronics Engineers, Incorporated.
[20]IEEE publications are available from The Institute of Electrical and Electronics Engineers (http://standards.ieee.org/).

IEEE Std 2030.5™, IEEE Adoption of Smart Energy Profile 2.0 Application Protocol Standard.

IEEE Std C37.90.1™, IEEE Standard Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus.

IEEE Std C37.90.2™, IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers.

IEEE Std C50.12™, IEEE Standard for Salient-Pole 50 Hz and 60 Hz Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications Rated 5 MVA and Above.

IEEE Std C50.13™, IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above.

IEEE Std C62.41.2™, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000 V and less) AC Power Circuits.

IEEE Std C62.45™, IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000 V and Less) AC Power Circuits.

IEEE Std C62.92.1™, IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems—Part I: Introduction.

3. Definitions and acronyms

For the purposes of this document, the following terms and definitions apply. The *IEEE Standards Dictionary Online* should be consulted for terms not defined in this document.[21]

NOTE—Defined terms and acronyms are italicized throughout the standard.[22]

3.1 Definitions

abnormal operating performance category: The grouping for a set of requirements that specify technical capabilities and settings for a DER under abnormal operating conditions, i.e., outside the *continuous operation* region.

applicable voltage: Electrical quantities that determine the performance of a Local EPS or DER specified with regard to the *reference point of applicability*, individual phase-to-neutral, phase-to-ground, or phase-to-phase combination and time resolution.

NOTE—*Applicable voltages* are used as a synonym for *applicable frequency,* which can be derived from the *applicable voltages*.

area electric power system (Area EPS): An EPS that serves Local EPSs.

NOTE—Typically, an *Area EPS* has primary access to public rights-of-way, priority crossing of property boundaries, etc., and is subject to regulatory oversight. See Figure 2.

area electric power system operator (Area EPS operator): The entity responsible for designing, building, operating, and maintaining the *Area EPS*.

[21]*IEEE Standards Dictionary Online* subscription is available at http://dictionary.ieee.org.
[22]Notes in text, tables, and figures of a standard are given for information only and do not contain requirements needed to implement this standard.

authority governing interconnection requirements (AGIR): A cognizant and responsible entity that defines, codifies, communicates, administers, and enforces the policies and procedures for allowing electrical interconnection of DER to the *Area EPS*. This may be a regulatory agency, public utility commission, municipality, cooperative board of directors, etc. The degree of AGIR involvement will vary in scope of application and level of enforcement across jurisdictional boundaries. This authority may be delegated by the cognizant and responsible entity to the *Area EPS operator* or *bulk power system* operator.

NOTE—Decisions made by an authority governing interconnection requirements should consider various stakeholder interests, including but not limited to Load Customers, *Area EPS operators*, *DER operators*, and *bulk power system* operator.

authority having jurisdiction: Authority having the rights to inspection and approval of the design and construction of Local EPS premise electrical systems.

available active power: Active power that a DER can deliver to the *Area EPS* subject to the availability of the DER's primary source of energy.

NOTE—Examples are solar irradiance in the case of a photovoltaic DER and wind speed in case of a wind turbine generator.

bulk power system (BPS): Any electric generation resources, transmission lines, interconnections with neighboring systems, and associated equipment.

cease to energize: Cessation of active power delivery under steady-state and transient conditions and limitation of reactive power exchange.

NOTE 1—This may lead to momentary cessation or trip.

NOTE 2—This does not necessarily imply, nor exclude disconnection, isolation, or a trip.

NOTE 3—Limited reactive power exchange may continue as specified, e.g., through filter banks.

NOTE 4—Energy storage systems are allowed to continue charging but are allowed to cease from actively charging when the maximum state of charge (maximum stored energy) has been achieved.

NOTE 5—Refer to 4.5 for additional details.

clearing time: The time between the start of an abnormal condition and the DER ceasing to energize the *Area EPS*. It is the sum of the detection time, any adjustable time delay, the operating time plus arcing time for any interposing devices (if used), and the operating time plus arcing time for the interrupting device (used to interconnect the DER with the *Area EPS*).

continuous operation: Exchange of current between the DER and an EPS within prescribed behavior while connected to the *Area EPS* and while the *applicable voltage* and the system frequency is within specified parameters.

continuous operation region: The performance operating region corresponding to *continuous operation.*

distributed energy resource (DER): A source of electric power that is not directly connected to a bulk power system. DER includes both generators and energy storage technologies capable of exporting active power to an EPS. An interconnection system or a supplemental DER device that is necessary for compliance with this standard is part of a DER.[23]

NOTE 1—Controllable loads used for demand response are not included in the definition of DER.

[23]Equivalent to "distributed resources (DR)" as defined and used in IEEE Std 1547-2003.

NOTE 2—See Figure 2.

distributed energy resource operator (DER operator): The entity responsible for operating and maintaining the distributed energy resource.

distributed energy resource (DER) unit: An individual DER device inside a group of DER that collectively form a system.

distributed energy resource managing entity (DER Managing Entity): An entity that monitors and manages the DER through the *local DER communication interface*. The DER managing entity could be for example a utility, an aggregator, a building energy management system, or other.

disturbance period: The range of time during which the *applicable voltage* or the system frequency is outside the *continuous operation* region.

electric power system (EPS): Facilities that deliver electric power to a load.

NOTE—This may include generation units. See Figure 2.

energize: Active power outflow of the DER to an EPS under any conditions (e.g., steady state and transient).

enter service: Begin operation of the DER with an energized Area EPS.

flicker: The subjective impression of fluctuating luminance caused by voltage fluctuations.

NOTE—Above a certain threshold, flicker becomes annoying. The annoyance grows very rapidly with the amplitude of the fluctuation. At certain repetition rates even very small amplitudes can be annoying (IEEE Std 1453).

intentional island: A planned electrical island that is capable of being energized by one or more Local EPSs. These (1) have DER(s) and load, (2) have the ability to disconnect from and to parallel with the Area EPS, (3) include one or more Local EPS(s), and (4) are intentionally planned.

NOTE—An intentional island may be an *intentional Area EPS island* or an *intentional Local EPS island* (also: "facility island").

intentional Area EPS island: An *intentional island* that includes portions of the Area EPS.

intentional Local EPS island: An intentional island that is totally within the bounds of a Local EPS.

interconnection: The result of the process of adding DER to an Area EPS, whether directly or via intermediate Local EPS facilities.

interconnection equipment: Individual or multiple devices used in an interconnection system.

interconnection system: The collection of all interconnection and interoperability equipment and functions, taken as a group, used to interconnect a DER to an Area EPS.[24]

interface: An electrical or logical connection from one entity to another that supports one or more energy or data flows implemented with one or more power or data links.

interoperability: The capability of two or more networks, systems, devices, applications, or components to externally exchange and readily use information securely and effectively. (IEEE Std 2030® [B23])

[24]This term was frequently used in IEEE Std 1547-2003. Given the scope of the present standard, which may have implications to the design of the entirety of the DER, this standard uses the term "DER" in most places.

inverter: A machine, device, or system that changes direct-current power to alternating-current power.

island: A condition in which a portion of an Area EPS is energized solely by one or more Local EPSs through the associated PCCs while that portion of the Area EPS is electrically separated from the rest of the Area EPS on all phases to which the DER is connected. When an island exists, the DER energizing the island may be said to be "islanding".

load: Devices and processes in a local EPS that use electrical energy for utilization, exclusive of devices or processes that store energy but can return some or all of the energy to the local EPS or Area EPS in the future.

local DER communication interface: A local interface capable of communicating to support the information exchange requirements specified in this standard for all applicable functions that are supported in the DER.

local electric power system (Local EPS): An EPS contained entirely within a single premises or group of premises.

NOTE—See Figure 2.

mandatory operation: Required continuance of active current and reactive current exchange of DER with Area EPS as prescribed, notwithstanding disturbances of the Area EPS voltage or frequency having magnitude and duration severity within defined limits.

mandatory operation region: The performance operating region corresponding to *mandatory operation*.

medium voltage: A class of nominal system voltages equal to or greater than 1 kV and less than or equal to 35 kV.

NOTE—IEEE standards are not unanimous in establishing the range for "medium voltage".

momentary cessation: Temporarily *cease to energize* an EPS, while connected to the Area EPS, in response to a disturbance of the *applicable voltages* or the system frequency, with the capability of immediate Restore Output of operation when the *applicable voltages* and the system frequency return to within defined ranges.

momentary cessation operation region: The performance operating region corresponding to momentary cessation.

manufacturer stated measurement accuracy: Accuracy declared by the manufacturer, at which a DER measures the *applicable voltage*, current, power, frequency, or time.

nameplate ratings: Nominal voltage (V), current (A), maximum active power (kW), apparent power (kVA), and reactive power (kvar) at which a DER is capable of sustained operation.

NOTE—For Local EPS with multiple DER units, the aggregate DER nameplate rating is equal to the sum of all DERs nameplate rating in the Local EPS, not including aggregate capacity limiting mechanisms such as coincidence factors, plant controller limits, etc., that may be applicable for specific cases.

normal operating performance category: The grouping for a set of requirements that specify technical capabilities and settings for DER under normal operating conditions, i.e., inside the *continuous operation* region.

open loop response time: The duration from a step change in control signal input (reference value or system quantity) until the output changes by 90% of its final change, before any overshoot.

NOTE 1—The control loop considered in this definition refers to the DER control system in conjunction with the Area EPS. The "open loop" response time is equal to the DER control response time when the DER is interconnected with a stiff grid (ideal voltage source).

NOTE 2—The open loop response time is equal to 2.3 times the time constant of a first-order (i.e., single lag) system.

operating mode: Mode of DER operation that determines the performance during normal or abnormal conditions.

performance operating region: A region bounded by point pairs consisting of magnitude (voltage or frequency) and cumulative time duration which are used to define the operational performance requirements of the DER.

permissive operation: Operating mode where the DER performs ride-through either in *mandatory operation* or in *momentary cessation*, in response to a disturbance of the *applicable voltages* or the system frequency.

permissive operation region: The performance operating region corresponding to permissive operation.

permit service: A setting that indicates whether a DER is allowed to enter or remain in service.

per unit (p.u.) / percent of (%): Quantity expressed as a fraction of a defined base unit quantity. For active power (active current), the base quantity is the rated active power (rated active current). For apparent power (current), the base quantity is the rated apparent power (rated current). For system frequency, the base quantity is the nominal frequency (i.e., 60.0 Hz in North America). Quantities expressed in per unit can be converted to quantities expressed in percent of a base quantity by multiplication with 100.

point of common coupling (PCC): The point of connection between the Area EPS and the Local EPS.

NOTE 1—See Figure 2.

NOTE 2—Equivalent, in most cases, to "service point" as specified in the National Electrical Code® (NEC®) [B31] and the National Electrical Safety Code® (NESC®) [B1].

point of distributed energy resources connection (point of DER connection–PoC): The point where a DER unit is electrically connected in a Local EPS and meets the requirements of this standard exclusive of any load present in the respective part of the Local EPS.

NOTE 1—See Figure 2.

NOTE 2—For (a) DER unit(s) that are not self-sufficient to meet the requirements without (a) supplemental DER device(s), the point of DER connection is the point where the requirements of this standard are met by DER (a) device(s) in conjunction with (a) supplemental DER device(s) exclusive of any load present in the respective part of the Local EPS.

post-disturbance period: The period starting upon the return of all *applicable voltages* or the system frequency to the respective ranges of the *mandatory operation* region or *continuous operation* region.

pre-disturbance period: The time immediately before a *disturbance period*.

protective function(s): The behavior whose purpose is to maintain safe operations and/or maintain safe conditions.

range of allowable settings: The range within which settings may be adjusted to values other than the specified default settings.

reference point of applicability (RPA): The location where the interconnection and interoperability performance requirements specified in this standard apply.

regional reliability coordinator: The functional entity that maintains the real-time operating reliability of the bulk electric power within a reliability coordinator area.

restore output: Return operation of the DER to the state prior to the abnormal excursion of voltage or frequency that resulted in a ride-through operation of the DER.

return to service: Enter service following recovery from a trip.

ride-through: Ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.

simulated utility: An assembly of variable frequency and variable voltage test equipment used to simulate an Area EPS.

step response: The output as a function of time *t* when the input is a step.

supplemental DER device: Any equipment that is used to obtain compliance with some or all of the interconnection requirements of this standard.

NOTE—Examples include capacitor banks, STATCOMs, harmonic filters that are not part of a DER unit, protection devices, plant controllers, etc.

total rated-current distortion (TRD): The total root-sum-square of the current distortion components (including harmonics and inter-harmonics) created by the DER unit expressed as a percentage of the DER rated current capacity (I_{rated}).

trip: Inhibition of immediate return to service, which may involve disconnection.

NOTE—Trip executes or is subsequent to cessation of energization.

type test: A test of one or more devices manufactured to a certain design to demonstrate, or provide information that can be used to verify, that the design meets the requirements specified in this standard.

unintentional island: An unplanned island.

zero-sequence continuity: Circuit topology providing continuity between two defined points in the zero sequence network representation.

NOTE—A transformer that has a delta or ungrounded-wye winding in the topological path between the defined points produces discontinuity of the zero-sequence network.

3.2 Acronyms

AGC	automatic generation control
AHJ	authority having jurisdiction
AGIR	authority governing interconnection requirements
Area EPS	area electric power system
Area EPS operator	area electric power system operator

BPS	bulk power system
DER	distributed energy resources
DER operator	distributed energy resources operator
EMS	energy management system
EMI	electromagnetic interference
EPS	electric power system
ESS	energy storage system
FIDVR	fault-induced delayed voltage recovery
Local EPS	local electric power system
NP	network protector
NRTL	nationally recognized testing laboratory
PCC	point of common coupling
PoC	point of DER connection
PV	photovoltaic
RMS	root mean square
ROCOF	rate of change of frequency
RPA	reference point of applicability
TRD	total rated-current distortion

4. General interconnection technical specifications and performance requirements

4.1 Introduction

The reference point of applicability (RPA) is the location where the interconnection and interoperability performance requirements specified in this standard shall be met. The electrical quantities referred to in this standard are those at the RPA, unless stated otherwise in this standard.

The performance requirements of this standard apply to interconnection of either a single DER unit based on that unit's rating or multiple DER units within a single Local EPS ("DER system"), based on the aggregate rating of all the DER units that are within the Local EPS. The capabilities and functions of the DER hardware and software that affect the *Area EPS* are required to meet this standard regardless of their location on the EPS. The performance requirements in this standard are functional and do not specify any particular equipment or equipment type.

The technical specifications and performance requirements specified here are universally needed for interconnection and interoperability of DER[25] and will be sufficient for most installations.[26] The applicability of certain specifications and requirements are dependent on application considerations. For these, the requirements are provided in terms of a limited number of technology-neutral *performance categories*, for which it is the responsibility of the *authority governing interconnection requirements*

[25] For example, synchronous machines, induction machines, or static power inverters/converters.
[26] Additional technical requirements may be necessary for some limited situations.

(AGIR) to determine applicability. Guidelines on criteria for assignment of DER *performance categories* are given in Annex B.

DER shall be designed and installed such that it meets the performance and test and verification requirements described in Clause 4 to Clause 11 of this standard. Unless specified otherwise, the term “DER” means “DER system”. In specific cases, “DER unit” is explicitly stated.

4.2 Reference points of applicability (RPA)

The characteristics of the Local EPS and DER shall determine the *reference point of applicability* (RPA). Except as otherwise stated in this standard, the RPA for all performance requirements of this standard shall be the *point of common coupling* (PCC).

Alternatively, for Local EPSs where zero sequence continuity[27] between the PCC and PoC is maintained and either of the following conditions apply, the RPA for performance requirements of this standard may be the *point of DER connection* (PoC), or by mutual agreement between the *Area EPS* operator and the *DER operator*, at any point between, or including, the PoC and PCC:

a) Aggregate DER nameplate rating of equal to or less than 500 kVA, *or*

b) Annual average load demand[28] of greater than 10% of the aggregate DER nameplate rating, and where the Local EPS is not capable of, or is prevented from, exporting more than 500 kVA for longer than 30 s.

For all other Local EPSs meeting either of the conditions a) or b) above but not meeting the requirement for zero sequence continuity, the RPA for performance requirements other than the response to *Area EPS* abnormal conditions specified in 6.2 and 6.4 shall be the PoC, or by mutual agreement between the *Area EPS operator* and the *DER operator*, at any point between, or including, the PoC and PCC. The RPA for performance requirements of 6.2 and 6.4 shall be a point between, or including, the PoC and PCC that is appropriate to detect the abnormal voltage conditions.[29, 30]

Where the RPA is not at the PCC, any equipment or devices in the Local EPS between the RPA and the PCC shall not preclude the DER from meeting the disturbance ride-through requirements specified in 6.4.2 and 6.5.2.[31]

For Local EPS where aggregate DER nameplate rating is greater than 500 kVA, and annual average load demand[28] is greater than 10% of the aggregate DER nameplate rating, and the Local EPS is capable of, and is not prevented from, exporting more than 500 kVA for longer than 30 s, the RPA shall be the PCC and

[27] When the zero sequence continuity is broken, for example by a delta-wye transformer between the PCC and the PoC, the voltages at the PoC may not be representative of the voltages at the PCC under abnormal voltage conditions. Examples of issues created by this condition include the following:
— Difficulty of ‘sensing’ single-phase-to-ground faults or failure to detect ground-fault overvoltages. Note that 7.4.1 specifies requirements for ground-fault overvoltage;
— Detecting abnormal voltage conditions when a DER back-feeds into the grid during a balanced open-phase condition;
— Ability of detecting Area EPS open-phase by the DER is diminished.

[28] As calculated by Area EPS operator.

[29] The intent of meeting the response to Area EPS abnormal voltage conditions requirements of 6.4 at the PCC is to appropriately detect ground faults and ground-fault overvoltage at the PCC.

[30] For DER that are permitted to use the PoC as the RPA, the location selected as the RPA may be different for each of the various functional requirements defined in Clause 5.

[31] Examples are undervoltage and overcurrent relays within the local EPS between the RPA and PCC that are set such that they may trip the DER during the voltage disturbance ride-through operation for short-circuit faults other than ones on the Area EPS circuit section to which the DER is connected. This does not preclude selectively tripping DER for faults on the Area EPS as specified in 6.2.1.

performance requirements specified in 5.2 for reactive power capability and in Clause 7 for power quality may be evaluated excluding the influence of the Local EPS load.

Figure H.1 illustrates a decision tree to determine the RPA for Local EPS where zero sequence continuity is maintained. Figure H.2 illustrates a decision tree to determine the RPA for Local EPS where zero sequence continuity is not maintained.

4.3 Applicable voltages

The *applicable voltages*[32] determine the performance of a Local EPS or DER and are the electrical quantities specified with regard to the reference point of applicability, individual phase-to-neutral, phase-to-ground, or phase-to-phase combination and time resolution.

For DER with a PCC located at the medium-voltage level, the *applicable voltages* shall be determined by the configuration and nominal voltage of the Area EPS at the PCC. For DER with a PCC located at the low-voltage[33] level, the *applicable voltages* shall be determined by the configuration of the low-voltage winding of the Area EPS transformer(s) between the medium-voltage system and the low-voltage system. The *applicable voltages* that shall be detected are shown in Table 1 and Table 2. For multi-phase systems, the requirements for *applicable voltages* shall apply to all phases.

Table 1—Applicable voltages when PCC is located at medium voltage

Area EPS at PCC	Applicable voltages
Three-Phase, Four-Wire	Phase-to-phase and phase-to-neutral
Three-Phase, Three-Wire, Grounded	Phase-to-phase and phase-to-ground
Three-Phase, Three-Wire, Ungrounded	Phase-to-phase
Single-Phase, Two-Wire	Phase-to-2nd wire (the 2nd wire may be either a neutral or a 2nd phase)

Table 2—Applicable voltages when PCC is located at low voltage

Low-voltage winding configuration of Area EPS transformer(s)[a]	Applicable voltages
Grounded Wye, Tee, or Zig-Zag[b]	Phase-to-phase and phase-to-neutral, or Phase-to-phase and phase-to-ground
Ungrounded Wye, Tee, or Zig-Zag	Phase-to-phase or phase-to-neutral
Delta[c]	Phase-to-phase
Single-Phase 120/240 V (split-phase or Edison connection)	Line-to-neutral—for 120 V DER units Line-to-line—for 240 V DER units[d]

[a]A three-phase transformer or a bank of single-phase transformers may be used for three-phase systems.
[b]For 120/208 V two-phase services, line-to-line voltages shall be sufficient.
[c]Including delta with mid tap connection (grounded or ungrounded).
[d]Sensing line-to-neutral on both legs of a 120/240 V split-phase or Edison connection effectively senses the line-to-line and is therefore compliant with this requirement. Sensing line-to-ground may also be used; however, the ground connection should only be used for voltage sensing purposes.

The applicable frequency is the fundamental-frequency component. The *applicable voltages* shall be quantified as the effective (RMS) values over the preceding fundamental frequency period, unless otherwise specified in this standard.

[32] *Applicable voltages* are used in synonym for *applicable frequency*, which can be derived from the *applicable voltages*.
[33] 1000 V and less per IEEE Std C62.41.2 and IEEE Std C62.45.

For voltage-reactive power[34] (volt-var) mode requirements in 5.3.3 and voltage-active (real) power[35] mode requirements in 5.4.2 where DER do not respond to individual phase voltages, the *applicable voltages* are quantified as the average of the three-phase effective (RMS) values or alternatively positive sequence component of voltages over one fundamental frequency period.

For voltage trip and ride-through requirements in 6.4, the following shall apply:

- For low-voltage ride-through and undervoltage trip, the relevant voltage at any given time shall be the least magnitude of the individual *applicable voltages* relative to the corresponding nominal voltage.
- For high-voltage ride-through and overvoltage trip, the relevant voltage at any given time shall be the greatest magnitude of the *applicable voltages* relative to the corresponding nominal voltage.

For rate of change of frequency (ROCOF) ride-through requirements in 6.5.2.5, the ROCOF shall be the average rate of change of frequency over an averaging window of at least 0.1 s.

4.4 Measurement accuracy

The DER[36] shall meet the minimum steady-state[37] and transient[38] measurement and calculation[39] accuracy requirements for voltage, frequency, active power, reactive power, and time as specified in Table 3. Actual measurement and calculation accuracy of a DER shall be stated for each of the values above.

Table 3—Minimum measurement and calculation accuracy requirements for manufacturers[a]

Time frame	Steady-state measurements			Transient measurements		
Parameter	**Minimum measurement accuracy**	**Measure-ment window**	**Range**	**Minimum measurement accuracy**	**Measure-ment window**	**Range**
Voltage, RMS	(± 1% V_{nom})	10 cycles	0.5 p.u. to 1.2 p.u.	(± 2% V_{nom})	5 cycles	0.5 p.u. to 1.2 p.u.
Frequency[b]	10 mHz	60 cycles	50 Hz to 66 Hz	100 mHz	5 cycles	50 Hz to 66 Hz
Active Power	(± 5% S_{rated})	10 cycles	0.2 p.u. < P < 1.0 p.u.	Not required	N/A	N/A
Reactive Power	(± 5% S_{rated})	10 cycles	0.2 p.u. < Q < 1.0 p.u.	Not required	N/A	N/A
Time	1% of measured duration	N/A	5 s to 600 s	2 cycles	N/A	100 ms < 5 s

[a]Measurement accuracy requirements specified in this table are applicable for voltage THD < 2.5% and individual voltage harmonics <1.5%.
[b]Accuracy requirements for frequency are applicable only when the fundamental voltage is greater than 30% of the nominal voltage.

[34] Voltage-reactive power mode may also be commonly referred to as “volt-var” mode.
[35] Voltage-active power mode may also be commonly referred to as “volt-watt” mode.
[36] The DER includes any equipment required to meet the interconnection performance and interoperability requirements of the standard, including protective relays and measurement transducers.
[37] Steady-state measurements may be used for providing monitoring information through a *local DER communication interface* at the reference point of applicability as specified in Table 29 in 10.5.
[38] Transient measurements can be used by protective relays for achieving the mandatory voltage and frequency-tripping requirements as specified in 6.4.1 and 6.5.1.
[39] Only the fundamental parameters can actually be measured, e.g., time, voltage, and current. Other quantities are calculated based on the fundamental parameters measured, e.g., frequency, active power, and reactive power.

4.5 Cease to energize performance requirement

In the *cease to energize* state, the DER shall not deliver active power during steady-state or transient conditions. The requirements for *cease to energize* shall apply to the point of DER connection (PoC).

For Local EPS with aggregate DER rating less than 500 kVA, the reactive power exchange in the *cease to energize* state shall be less than 10% of nameplate DER rating and shall exclusively result from passive devices. For Local EPS with aggregate DER rating 500 kVA and greater, the reactive power exchange in the *cease to energize* state shall be less than 3% of nameplate DER rating and shall exclusively result from passive devices.[40]

If requested by the Area EPS operator, the DER operator shall provide the reactive susceptance that remains connected to the Area EPS in the *cease to energize* state.

Import of active power and reactive power exchange in the *cease to energize* state is permitted only for continuation of supply to DER housekeeping and auxiliary loads.

Alternatively, the requirements for *cease to energize* may be met by disconnecting[41] the local EPS, or the portion of the local EPS to which the DER is connected from the Area EPS. The DER may continue to deliver power to the portion of the Local EPS that is disconnected from the Area EPS.[42]

4.6 Control capability requirements

The DER shall be capable of responding to external inputs[43] as specified in this subclause.

4.6.1 Capability to disable permit service

The DER shall be capable of disabling the permit service setting and shall *cease to energize* the Area EPS and trip in no more than 2 s.[44]

4.6.2 Capability to limit active power

The DER shall be capable of limiting active power as a percentage of the nameplate active power rating. The DER shall limit its active power output to not greater than the active power limit set point in no more than 30 s or in the time it takes for the primary energy source to reduce its active power output to achieve the requirements of the active power limit set point, whichever is greater.[45] In cases where the DER is supplying loads in the Local EPS, the active power limit set point may be implemented as a maximum active power export to the Area EPS. Under mutual agreement between the *Area EPS operator* and the *DER operator*, the DER may be required to reduce active power below the level needed to support Local EPS loads.

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[40] In cases where the Area EPS is isolated, the passive reactive power devices of the DER will rapidly discharge by Area EPS loads and transformer magnetization and cease to exchange reactive power with the isolated Area EPS.
[41] For example, via a separate disconnection device.
[42] This may allow DER units to continue to energize the isolated Local EPS and supply local loads when disconnected from the Area EPS.
[43] The external input may come through a manual DER control panel or through the *local DER communication interface* specified in Clause 10.
[44] This function is not intended to necessarily meet all requirements for protection, such as direct transfer trip. The objective of this requirement is related to bulk system operation.
[45] Linear ramping and step-wise ramping with small step sizes may be desirable.

4.6.3 Execution of mode or parameter changes

Transition between modes shall commence in no more than 30 s after the mode setting change is received at the local DER communication interface. Changes of control functional modes shall be executed such that the DER output is transitioned smoothly over a time period between 5 s and 300 s.

Ramping of DER output is not required for control parameter setting changes. For all control and protective function parameter settings, the time following the input to the *local DER communication interface* and preceding the point in time when the invoked action begins shall be no greater than 30 s.

4.7 Prioritization of DER responses

Requirements set forth in Clause 5 and Clause 6 shall be prioritized as follows:[46]

a) The response to disabling permit service setting specified in 4.6.1 shall take precedence over any requirements within Clause 5 and Clause 6.

b) DER tripping requirements specified in 6.2, 6.4.1, and 6.5.1 shall take precedence over any other requirements within Clause 5 and Clause 6, subject to the following:

   1) Where the prescribed trip duration settings for the respective voltage or frequency magnitude are set at least 160 ms or 1% of the prescribed tripping time, whichever is greater, beyond the prescribed ride-through duration, the DER shall comply with the ride-through requirements specified in 6.4.2 and 6.5.2 prior to tripping.

   2) In all other cases, the ride-through requirements shall apply until 160 ms or 1% of the prescribed tripping time, whichever is greater, prior to the prescribed tripping time.

c) DER ride-through requirements specified in 6.4.2 and 6.5.2 shall take precedence over all other requirements within Clause 5 and Clause 6, with the exception of tripping requirements listed in item b) above. Ride-through may be terminated by the detection of an *unintentional island* specified in 8.1. However, false detection of an *unintentional island* that does not actually exist shall not justify non-compliance with ride-through requirements. Conversely, ride-through requirements specified in Clause 6 shall not inhibit the islanding detection performance specified in 8.1 where a valid unintentional islanding condition exists.

d) The voltage-active power mode requirements specified in 5.4.2 and frequency-droop (frequency-power) response requirements specified in 6.5.2.7 shall take precedence over all other requirements within Clause 5 and Clause 6, with the exception of tripping and ride-through requirements listed in item b) and item c) above. If both voltage-active power and frequency-droop modes are active, the lesser of the power value shall take precedence.

e) The response to active power limit signal specified in 4.6.2 shall take precedence over all other requirements within Clause 5 and Clause 6, with the exception of tripping and ride-through requirements listed in item b) and item c) above, and voltage-active power mode requirements and frequency-droop response requirements listed in item d).

f) The voltage regulation functions specified in 5.3 shall take precedence over any remaining requirements within Clause 5 and Clause 6.

[46] Based on the actual settings of the control modes, a mode with lower priority may still take effect prior to a mode with higher priority.

4.8 Isolation device

When required by the Area EPS operating practices, a readily accessible, lockable, visible-break isolation device shall be located between the Area EPS and the DER.[47]

4.9 Inadvertent energization of the Area EPS

The DER shall not energize the Area EPS when the Area EPS is de-energized. Exceptions may be given for *intentional Area EPS islands* per 8.2 at the discretion of the Area EPS operator.

4.10 Enter service

4.10.1 Introduction

The *enter service* criteria for DER of Category I, Category II, and Category III are specified in Table 4.[48] The active power performance during entering service is specified in 4.10.3. The requirements of 4.10 apply equally for return to service after trip as specified in 6.6.

4.10.2 Enter service criteria

When entering service, the DER shall not energize the Area EPS until the *applicable voltage* and system frequency are within the ranges specified in Table 4 and the permit service setting is set to "Enabled".[49]

Table 4—Enter service criteria for DER of Category I, Category II, and Category III

Enter service criteria		Default settings	Ranges of allowable settings
Permit service		Enabled	Enabled/Disabled
Applicable voltage within range	Minimum value	≥ 0.917 p.u.[a]	0.88 p.u. to 0.95 p.u.
	Maximum value	≤ 1.05 p.u.	1.05 p.u. to 1.06 p.u.
Frequency within range	Minimum value	≥ 59.5 Hz	59.0 Hz to 59.9 Hz
	Maximum value	≤ 60.1 Hz	60.1 Hz to 61.0 Hz

[a]This corresponds to the Range B of ANSI C84.1, Table 1, column for service voltage of 120−600 V.

4.10.3 Performance during entering service

During entering service, the DER shall be capable of the following:

a) Prevent *enter service* when permit service setting is disabled.

b) DER shall be capable of delaying *enter service* by an intentional adjustable minimum delay when the Area EPS steady-state voltage and frequency are within the ranges specified in Table 4. The adjustable range of the minimum intentional delay shall be 0 s to 600 s with a default minimum delay of 300 s.

[47] The isolation device should be clearly marked to include signage per The National Electrical Code® [B31], as applicable.
[48] Refer to Annex B for more information on categories.
[49] The *enter service* criteria in Table 4 specify the conditions for which a DER is permitted to *enter service*; these criteria do not mandate any DER to *enter service* or stay in operation for the specified voltage and frequency conditions.

c) DER shall increase output of active power,[50] or exchange of active power for energy-storage-DER, during *enter service* as specified. Active power shall increase linearly, or in a stepwise linear ramp, with an average rate-of-change not exceeding the DER nameplate active power rating divided by the enter service period. The duration of the *enter service* period shall be adjustable over a range of 1 s to 1000 s with a default time of 300 s.[51] The maximum active power increase of any single step during the *enter service* period shall be less than or equal to 20% of the DER nameplate active power rating. Where a stepwise ramp is used, the rate of change over the period between any two consecutive steps shall not exceed the average rate-of-change over the full *enter service* period. This requirement is a maximum ramp rate requirement and the DER may increase output slower than specified.

Exception 1: For Local EPS that have an aggregate DER rating of less than 500 kVA, individual DER units may increase output of active power with no limitation of the rate-of-change, following an additional randomized time delay with a default maximum time random interval of 300 s, and with an adjustable range for the maximum time random interval of 1 s to 1000 s.

Exception 2: Increase of output of active power by Local EPS having an aggregate DER rating of equal to or greater than 500 kVA and increasing output with active power steps greater than 20% of nameplate active power rating shall require approval of the Area EPS operator in coordination with the regional reliability coordinator.

4.10.4 Synchronization

The DER shall parallel with the Area EPS without causing step changes in the RMS voltage at the PCC exceeding 3% of nominal when the PCC is at medium voltage, or exceeding 5% of nominal when the PCC is at low voltage.

DER that produce fundamental voltage before connecting to the Area EPS[52] shall not be synchronized outside of the tolerances specified in Table 5.[53, 54] The synchronization limits stated in Table 5 may be waived by the Area EPS operator if paralleling does not exceed the limitation of voltage fluctuations induced by the DER requirements specified in 7.2.

[50] For Restore Output of active power after Return to Service, direction of active power may be negative (charging) for Energy Storage DER, e.g., return to frequency reduction via charging through droop or dispatch control, if operating for that purpose prior to trip. This requirement does not exclude use of alternate means to meet this requirement.
[51] Base values for quantities expressed in per unit and percent of are specified in 3.1.
[52] Examples may include synchronous generators, self-excited (grid-forming) inverters, or self-excited induction generators.
[53] These parameters are maximum synchronization tolerances and by no means require that DER equipment be designed to sustain these tolerances. If the equipment requires tighter tolerances and the synchronization is performed consistent with the equipment requirements, then the synchronization will be compliant with this subclause.
[54] For example, round rotor synchronous generators with ratings 10 MVA and larger and salient pole synchronous generators with ratings 5 MVA and larger may use the synchronization criteria described in IEEE Std 67, which are tighter than the ones specified here and can therefore meet the requirements of this standard.

Table 5—Synchronization parameter limits for synchronous interconnection to an EPS, or an energized Local EPS to an energized Area EPS

Aggregate rating of DER units (kVA)	Frequency difference (Δf, Hz)	Voltage difference (ΔV, %)	Phase angle difference ($\Delta\Phi$, °)
0–500	0.3	10	20
> 500–1 500	0.2	5	15
> 1 500	0.1	3	10

4.11 Interconnect integrity

4.11.1 Protection from electromagnetic interference (EMI)

The DER shall be compliant with IEEE Std C37.90.2, IEC 61000-4-3, or other applicable industry standards with a minimum electric field strength of 30 V/m.[55] The influence of EMI, having an electric field less than or equal to the value specified in this subclause, shall not result in a change in state or mis-operation of the DER that affects performance required by this standard.

4.11.2 Surge withstand performance

The interconnection system shall have the capability to withstand voltage and current surges in accordance with the interconnection system ratings and environments defined in IEEE Std C62.41.2, IEEE Std C37.90.1, IEEE Std C62.45, or IEC 61000-4-5, as applicable.

4.11.3 Paralleling device

Where used for isolation of a DER unit that continues to produce voltage after isolation from the Area EPS, the DER paralleling-device shall be capable of withstanding 220% of the DER rated voltage across the paralleling device for an indefinite duration.[56]

4.12 Integration with Area EPS grounding

Unless specified otherwise by the Area EPS operator, the grounding scheme of the DER interconnection shall be coordinated with the ground fault protection of the Area EPS.[57]

4.13 Exemptions for emergency systems and standby DER

4.13.1 Exemptions for emergency systems

DER systems designated by *authority having jurisdiction* as emergency, legally required, or critical operations power systems providing backup power to hospitals, fire stations or other emergency facilities as defined by applicable industry code,[58] shall be exempt from the following:

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[55] Information on references can be found in Clause 2.

[56] The paralleling device must be rated for 220% of nominal voltage to accommodate Area EPS and DER voltages that are out of phase with each other.

[57] Subclause 7.4 limits overvoltages produced by DER, including overvoltages caused by ground faults.

[58] In the United States, examples of applicable industry code are NFPA 110 [B32], NFPA 70 [B31], or the NESC [B1].

a) Voltage disturbance ride-through requirements specified in 6.4.2
b) Frequency disturbance ride-through requirements specified in 6.5.2
c) Interoperability, information exchange, information models, and protocols specified in Clause 10
d) Intentional islanding requirements specified in 8.2

and may *cease to energize* the Area EPS or may separate from the Area EPS without limitations.

4.13.2 Exemptions for standby DER

A DER that is only being operated in parallel to the Area EPS:

— For testing purposes only and tests are not performed more frequently than 30 times per year; or
— During load transfer in a period of less than 300 s to or from the Area EPS,

shall be exempt from the following:

a) Voltage disturbance ride-through requirements specified in 6.4.2
b) Frequency disturbance ride-through requirements specified in 6.5.2
c) Interoperability, information exchange, information models, and protocols specified in Clause 10
d) Intentional islanding requirements specified in 8.2

and may *cease to energize* the Area EPS or may separate from the Area EPS without limitations.

5. Reactive power capability and voltage/power control requirements

5.1 Introduction

Different characteristics and capabilities for response to voltage variations within the normal operating range are specified in certain parts of this subclause for *normal operating performance* Category A and Category B DER.[59] Table 6 specifies the attributes of voltage and reactive power control requirements specified in 5.3 and the voltage and active power control requirements specified in 5.4 to performance Category A and Category B DER. Under mutual agreement between Area EPS operator and DER operator, requirements other than those specified below are also permitted.

The Area EPS operator shall specify the DER performance category that is required. Guidance regarding the assignment of performance categories is provided in Annex B of this standard covering DER type, application purpose, and Area EPS characteristics.

The requirements of this subclause apply to the *continuous operation region* when the voltage is between 0.88 and 1.1 times the nominal voltage (V_N). Continued operation of functions defined in Clause 5 outside of the *continuous operation region* may be acceptable to support functions covered in 6.4. During abnormal voltage conditions, this reactive power range shall be provided subject to the limitations of the DER. The DER shall return to its pre-disturbance operating mode after the system voltage returns to its normal range.

The DER shall not cause the Area EPS primary circuit voltage at any location to go outside the requirements of ANSI C84.1 for primary service voltage.

[59] Refer to Annex B for definitions of Category A and Category B.

In addition, the DER shall not cause the Area EPS service voltage at any Local EPS to be outside of ANSI C84.1. This service voltage limitation shall not apply to the DER's Local EPS if it is served by a dedicated service transformer or dedicated feeder/circuit as determined by the Area EPS operator.

Table 6—Voltage and reactive/active power control function requirements for DER normal operating performance categories

DER category	Category A	Category B
Voltage regulation by reactive power control		
Constant power factor mode	Mandatory	Mandatory
Voltage—reactive power mode[a]	Mandatory	Mandatory
Active power—reactive power mode[b]	Not required	Mandatory
Constant reactive power mode	Mandatory	Mandatory
Voltage and active power control		
Voltage—active power (volt-watt) mode	Not required	Mandatory

[a]Voltage-reactive power mode may also be commonly referred to as "volt-var" mode.
[b]Active power-reactive power mode may be commonly referred to as "watt-var" mode.

5.2 Reactive power capability of the DER

The DER shall be capable of injecting reactive power (over-excited) and absorbing reactive power (under-excited) for active power output levels greater than or equal to the minimum steady-state active power capability (P_{min}), or 5% of rated active power, P_{rated} (kW) of the DER, whichever is greater.

When operating at active power output greater than 5% and less than 20% of rated active power, the DER shall be capable of exchanging reactive power up to the minimum reactive power value given in Table 7 multiplied by the active power output divided by 20% of rated active power.

Operation at any active power output above 20% of rated active power shall not constrain the delivery of reactive power injection or absorption, up to the capability specified in Table 7, as required by the active control function at the time, as defined in 5.3. Curtailment of active power to meet apparent power constraints is permissible. These reactive power requirements are illustrated in informative Figure H.3.[60]

Table 7—Minimum reactive power injection and absorption capability

Category	Injection capability as % of nameplate apparent power (kVA) rating	Absorption capability as % of nameplate apparent power (kVa) rating
A (at DER rated voltage)	44	25
B (over the full extent of ANSI C84.1 range A)	44	44

The DER may produce active power up to the kVA rating provided that the DER remains capable at all times to absorb or inject reactive power, to the full extent of the reactive power capability ranges defined above, as demanded by the reactive power control mode and corresponding settings established by the Area EPS operator.[61]

[60] This is commonly known as "reactive power priority" mode.
[61] The DER P_{rated} may be less than or equal to S_{rated}. The DER may need to reduce active power in order to meet the demanded reactive power in order to respect its apparent power limits.

5.3 Voltage and reactive power control

5.3.1 General

The DER shall provide voltage regulation capability by changes of reactive power. The approval of the Area EPS operator shall be required for the DER to actively participate in voltage regulation.

The voltage and reactive power control functions do not create a requirement for the DER to operate at points outside of the minimum reactive power capabilities specified in 5.2.

The DER shall, as specified in Table 6, provide the capabilities of the following mutually exclusive modes of reactive power control functions:

— Constant power factor mode

— Voltage-reactive power mode

— Active power-reactive power mode

— Constant reactive power mode

The DER shall be capable of activating each of these modes one at a time.

Constant power factor mode with unity power factor setting[62] shall be the default mode of the installed DER unless otherwise specified by the Area EPS operator.

The DER operator shall be responsible for implementing setting modifications and mode selections, as specified by the Area EPS operator within a time acceptable to the Area EPS operator. Under mutual agreement between the Area EPS operator and DER operator, reactive power control modes and implementations other than the ones listed above and described below shall be permitted.

Emergency or standby DERs[63] as specified in 4.13 shall only be required to operate in constant power factor mode.

5.3.2 Constant power factor mode

When in this mode, the DER shall operate at a constant power factor. The target power factor shall be specified by the Area EPS operator and shall not require reactive power exceeding the reactive capability requirements specified in 5.2. The power factor settings are allowed to be adjusted locally and/or remotely as specified by the Area EPS operator. The maximum DER response time to maintain constant power factor shall be 10 s or less.

5.3.3 Voltage-reactive power mode[64]

When in this mode, the DER shall actively control its reactive power output as a function of voltage following a voltage-reactive power piecewise linear characteristic. An example voltage-reactive power characteristic is shown in Figure H.4. The voltage-reactive power characteristic shall be configured in accordance with the default parameter values specified in Table 8 if not specified by the Area EPS

[62] DER may operate at any power factor, e.g., for the purpose of compensating for the reactive power demand of the Local EPS, as long as the power factor requirements specified by the Area EPS are met at the RPA.
[63] As defined by authority having jurisdiction.
[64] Category A default operation under voltage-reactive power mode is sometimes called 'voltage regulation with reactive droop'. Note however, that Category B deviates significantly from Category A operation.

operator. If specified by the Area EPS operator, the voltage-reactive power characteristic shall be configured using values in the optional adjustable range. The voltage-reactive power characteristics shall be adjustable locally and/or remotely as specified by the Area EPS operator.

Table 8—Voltage-reactive power settings for normal operating performance Category A and Category B DER

Voltage-reactive power parameters	Default settings		Ranges of allowable settings	
	Category A	Category B	Minimum	Maximum
V_{Ref}	V_N	V_N	0.95 V_N	1.05 V_N
V_2	V_N	$V_{\mathrm{Ref}} - 0.02\ V_N$	Category A: V_{Ref} Category B: $V_{\mathrm{Ref}} - 0.03\ V_N$	V_{Ref} [c]
Q_2	0	0	100% of nameplate reactive power capability, absorption	100% of nameplate reactive power capability, injection
V_3	V_N	$V_{\mathrm{Ref}} + 0.02\ V_N$	V_{Ref}[c]	Category A: V_{Ref} Category B: $V_{\mathrm{Ref}} + 0.03\ V_N$
Q_3	0	0	100% of nameplate reactive power capability, absorption	100% of nameplae reactive power capability, injection
V_1	0.9 V_N	$V_{\mathrm{Ref}} - 0.08\ V_N$	$V_{\mathrm{Ref}} - 0.18\ V_N$	$V_2 - 0.02\ V_N$[c]
Q_1[a]	25% of nameplate apparent power rating, injection	44% of nameplate apparent power rating, injection	0	100% of nameplate reactive power capability, injection[b]
V_4	1.1 V_N	$V_{\mathrm{Ref}} + 0.08\ V_N$	$V_3+0.02\ V_N$[c]	$V_{\mathrm{Ref}} + 0.18\ V_N$
Q_4	25% of nameplate apparent power rating, absorption	44% of nameplate apparent power rating, absorption	100% of nameplate reactive power capability, absorption	0
Open loop response time	10 s	5 s	1 s	90 s

[a]The DER reactive power capability may be reduced at lower voltage.
[b]If needed DER may reduce active power output to meet this requirement.
[c]Improper selection of these values may cause system instability.

The DER shall be capable of autonomously adjusting reference voltage (V_{Ref}) with V_{Ref} being equal to the low pass filtered measured voltage. The time constant shall be adjustable at least over the range of 300 s to 5000 s. The voltage-reactive power Volt-Var curve characteristic shall be adjusted autonomously as V_{Ref} changes. The approval of the Area EPS operator shall be required for the DER to autonomously adjust the reference voltage. Implementation of the autonomous V_{Ref} adjustability and the associated time constant shall be specified by the Area EPS operator.

5.3.4 Active power-reactive power mode

When in this mode, the DER shall actively control the reactive power output as a function of the active power output following a target piecewise linear active power-reactive power characteristic, without intentional time delay. In no case, shall the response time be greater than 10 s. Example active power-reactive power characteristic is shown in Figure H.5. The target characteristic shall be configured in accordance with the default parameter values shown in Table 9. The characteristics shall be allowed to be configured as specified by the Area EPS operator using the values specified in the optional adjustable range.

The left-hand side of Figure H.5 and corresponding requirements specified in Table 9 shall only apply to DER capable of absorbing active power.

The active power-reactive power characteristics are allowed to be adjusted locally and/or remotely as specified by the Area EPS operator.

Table 9—Active power-reactive power settings for normal operating performance Category A and Category B DER

Active power-reactive power parameters	Default settings		Ranges of allowable settings	
	Category A	**Category B**	**Minimum**	**Maximum**
P_3	P_{rated}		$P_2 + 0.1\ P_{rated}$	P_{rated}
P_2	$0.5\ P_{rated}$		$0.4\ P_{rated}$	$0.8\ P_{rated}$
P_1	The greater of $0.2\ P_{rated}$ and P_{min}		P_{min}	$P_2 - 0.1\ P_{rated}$
P'_1	The lesser of $0.2 \times P'_{rated}$ and P'_{min}		$P'_2 - 0.1\ P'_{rated}$	P'_{min}
P'_2	$0.5\ P'_{rated}$		$0.8\ P'_{rated}$	$0.4\ P'_{rated}$
P'_3	P'_{rated}		P'_{rated}	$P'_2 + 0.1\ P'_{rated}$
Q_3	25% of nameplate apparent power rating, absorption	44% of nameplate apparent power rating, absorption	100% of nameplate reactive power absorption capability	100% of nameplate reactive power injection capability
Q_2	0			
Q_1	0			
Q'_1	0			
Q'_2	0			
Q'_3	44% of nameplate apparent power rating, injection			

NOTE— P_{rated} is the nameplate active power rating of the DER.
P'_{rated} is the maximum active power that the DER can absorb.
P_{min} is the minimum active power output of the DER.
P'_{min} is the minimum, in amplitude, active power that the DER can absorb.
P' parameters are negative in value.

5.3.5 Constant reactive power mode

When in this mode, the DER shall maintain a constant reactive power. The target reactive power level and mode (injection or absorption) shall be specified by the Area EPS operator and shall be within the range specified in 5.2. The reactive power settings are allowed to be adjusted locally and/or remotely as specified by the Area EPS operator. The maximum DER response time to maintain constant reactive power shall be 10 s or less.

5.4 Voltage and active power control

5.4.1 General

Category B DER shall, as specified in Table 6, provide a voltage regulation capability by changes of active power. Enabling/disabling this function is at the discretion of the Area EPS operator. The default is that this function is disabled.

5.4.2 Voltage-active power mode

When in this mode, the DER shall actively limit the DER maximum active power as a function of the voltage following a voltage-active power piecewise linear characteristic. Two examples of these characteristics are shown in Figure H.6. The characteristic shall be configured in accordance with the default parameter values specified in Table 10 for the given DER *normal operating performance category*. The characteristic may be configured as specified by the Area EPS operator using the values in the adjustable range.[65]

If enabled, the voltage-active power mode shall remain active while any of the voltage-reactive power modes described in 5.3 are enabled. For DER that do not absorb active power, P_2, which is the minimum set point for active power generation due to overvoltage, is subject to the equipment capability. If P_2 is outside the *continuous operation region* of the DER, the active power generation is allowed to be reduced to the minimum DER capability instead of P_2 or DER shutting down.

DER that can inject and absorb active power, P'_2, which is the maximum set point for active power absorption change due to system overvoltage, is subject to the equipment capability. If P'_2 is outside the *continuous operation region* of the DER, the active power absorption is allowed to be reduced to the maximum absorption capability instead of P'_2 or DER shutting down.

The voltage-active power characteristics curves are allowed to be adjusted locally and/or remotely as specified by the Area EPS operator.

Table 10 —Voltage-active power settings for Category A and Category B DER

Voltage-active power parameters	Default settings	Ranges of allowable settings	
		Minimum	Maximum
V_1	1.06 V_N	1.05 V_N	1.09 V_N
P_1	P_{rated}	N/A	N/A
V_2	1.1 V_N	V_1 + 0.01 V_N	1.10 V_N
P_2 (*applicable to DER that can only generate active power*)	The lesser of 0.2 P_{rated} or P_{min}[a]	P_{min}	P_{rated}
P'_2 (*applicable to DER that can generate and absorb active power*)	0[b]	0	P'_{rated}
Open Loop Response Time	10 s[c]	0.5 s	60 s

[a] P_{min} is the minimum active power output in p.u. of the DER rating (i.e., 1.0 p.u.).
[b] P'_{rated} is the maximum amount of active power that can be absorbed by the DER. ESS operating in the negative real power half plane, through charging, shall follow this curve as long as available energy storage capacity permits this operation.
[c] Any settings for the open loop response time of less than 3 s shall be approved by the Area EPS operator with due consideration of system dynamic oscillatory behavior.

[65] As permitted by 4.6.2, for cases where the DER is supplying loads in the Local EPS, the DER active power may be implemented as a maximum active power export limit set point. The DER shall not be required to reduce active power below the level needed to support local loads.

6. Response to Area EPS abnormal conditions

6.1 Introduction

Abnormal conditions can arise on the Area EPS to which the DER shall appropriately respond. This response contributes to the stability of the Area EPS, safety of utility maintenance personnel and the general public, as well as the avoidance of damage to connected equipment, including the DER. DER response should consider the performance requirements of the Area EPS and the *bulk power system* (BPS) to which the Area EPS is connected.[66] All performance requirements specified in these subclauses shall be met at the *reference point of applicability* specified in 4.2 and shall refer to the *applicable voltages* specified in 4.3,[67] unless otherwise stated.

Different characteristics and capabilities for response to abnormal Area EPS conditions are specified in certain parts of this subclause for *abnormal operating performance* Category I, Category II, and Category III DER.

The Area EPS operator, as guided by the AGIR who determined applicability of the performance categories as outlined in 4.3,[68] shall specify which of *abnormal operating performance* Category I, Category II, or Category III performance is required.[69] Guidance regarding the assignment of *performance categories* is provided in Annex B of this standard.

With regard to ride-through as specified in 6.4.2 and 6.5.2 and methods utilized to meet the unintentional islanding detection as specified in 8.1, the following shall apply:

— While the DER is connected to an Area EPS that is connected to a *bulk power system*, any requirements for ride-through as specified in 6.4.2 and 6.5.2 shall not be falsely inhibited by any methods or design features utilized to meet the unintentional islanding detection as specified in 8.1 when an actual *unintentional island* condition does not exist.

— Conversely, the unintentional islanding detection requirements specified in 8.1 shall not be inhibited by ride-through as specified in 6.4.2 and 6.5.2 during valid unintentional islanding conditions.[70]

— While the DER is connected to an Area EPS that is not connected to a *bulk power system* (i.e., an *intentional Area EPS island*), requirements for ride-through as specified in 6.4.2 and 6.5.2 may not apply.[71]

All requirements related to the delivery of active power shall be subject to the availability of the DER's primary source of energy (*available active power*).[72] Abnormal voltage and frequency conditions shall not result in unavailability of DER's primary source of energy (*available active power*); otherwise, this shall be

[66] Distributed Energy Resources—Connection, Modeling, and Reliability Considerations, North American Electric Reliability Corporation (NERC), February 2017.
[67] Subclause 4.3 states: For low-voltage ride-through and undervoltage trip, the relevant voltage at any given time shall be the least magnitude of the individual *applicable voltages* relative to the corresponding nominal voltage. For high-voltage ride-through and overvoltage trip, the relevant voltage at any given time shall be the greatest magnitude of the *applicable voltages* relative to the corresponding nominal voltage.
[68] Refer to Annex B for further guidelines for DER performance category assignment.
[69] This may be subject to regulatory requirements that are outside the scope of this standard and may consider DER type, application purpose, future regional DER penetration, and the Area EPS characteristics.
[70] Also refer to prioritization of DER responses as specified in 4.7.
[71] Subclause 8.2 specifies requirements and criteria for *intentional Area EPS islands* and DER operating within an *intentional Area EPS island*.
[72] Decrease of solar irradiance in the case of a photovoltaic DER, or decrease of wind speed for a wind turbine generator, occurring during a voltage disturbance, are examples where DER power output decrease is compliant with this requirement.

deemed a failure to comply with ride-through of abnormal voltage and frequency conditions of this clause.[73]

All DER shall be field adjustable for the adjustable parameters specified in this clause.[74] The adjustability may be required via communication, if specified by the Area EPS operator as defined per the interoperability requirements specified in Clause 10.

The actual applied trip settings shall be specified by the Area EPS operator. If the Area EPS operator does not specify any settings, the default settings shall be used.

6.2 Area EPS faults and open phase conditions

6.2.1 Area EPS faults

For short-circuit faults on the Area EPS circuit section to which the DER is connected, the DER shall *cease to energize* and *trip* unless specified otherwise by the Area EPS operator.[75] This requirement shall not be applicable to faults that cannot be detected by the Area EPS protection systems.

NOTE 1—DER can desensitize detection of faults that can be detected by the Area EPS protection systems prior to the interconnection of the DER. Adjustments to the settings of the Area EPS protection systems or changes to the DER interconnection parameters, which can compensate for DER's fault current contribution, may be needed to maintain proper fault detection time and protective relaying coordination intervals acceptable to the Area EPS operator.

NOTE 2—The presence of a ground source within the Local EPS can pose a back-feed risk to the distribution system even when the DER is otherwise disconnected.

6.2.2 Open phase conditions

The DER shall detect and *cease to energize* and *trip* all phases to which the DER is connected for any open phase condition occurring directly at the reference point of applicability per 4.2 and the *applicable voltages* per 4.3. The DER shall *cease to energize* and *trip* within 2.0 s of the open phase condition.

6.3 Area EPS reclosing coordination

Appropriate means shall be implemented to help ensure that Area EPS automatic reclosing onto a circuit remaining energized by the DER does not expose the Area EPS to unacceptable stresses or disturbances due to differences in instantaneous voltage, phase angle, or frequency between the separated systems at the instant of the reclosure (e.g., out-of-phase reclosing).[76]

Operation in *momentary cessation* operating mode meets this *cease to energize* requirement. *Restore output* behavior shall be coordinated with Area EPS reclosing timing.

[73] Examples of non-compliant decrease of active power availability are loss of control power to the power conversion device or prime mover, or loss of auxiliary power.
[74] For example, voltage or frequency magnitude, time duration, droop, deadband.
[75] The Area EPS Operator may elect to use sequential tripping for the smaller DER with relatively low impact and allow the DER to *cease to energize* after the protective device on the Area EPS opened.
[76] Appropriate means may include, for example, Area EPS measures to block reclosing if the circuit remains energized, or existence of low DER penetration and DER technology-types such that energization would not be maintained for as long as the time of reclosing, or means to cease energization by DER when the Area EPS is isolated (e.g., transfer trip, or reliance on islanding detection requirements as specified in 8.1).

In addition to these requirements, the requirements from 4.10 shall be considered. Voltage ride-through requirements for consecutive temporary voltage disturbances caused by a reclosing sequence are specified by 6.4.2.5.

6.4 Voltage

6.4.1 Mandatory voltage tripping requirements

When any *applicable voltage* is less than an undervoltage threshold, or greater than an overvoltage threshold, as defined in this subclause, the DER shall *cease to energize* the Area EPS and trip within the respective *clearing time* as indicated.[77] Under and overvoltage tripping thresholds and *clearing times* shall be adjustable over the *ranges of allowable settings* specified in Table 11 for *abnormal operating performance* Category I, Table 12 for Category II, or Table 13 for Category III. Unless specified otherwise by the Area EPS operator, default settings shall be used.

The voltage and time set points shall be field adjustable and may be remotely adjustable per the interoperability requirements specified in Clause 10.

The *ranges of allowable settings* do not mandate a requirement for the DER to ride through this magnitude and duration of abnormal voltage condition. The Area EPS operator may specify the voltage thresholds and maximum *clearing times* within the *ranges of allowable settings*; settings outside of these ranges shall only be allowed as necessary for DER equipment protection and shall not conflict with the voltage disturbance ride through requirements specified in 6.4.2.

Two overvoltage trip functions, OV1 and OV2, and two undervoltage trip functions, UV1 and UV2 apply simultaneously to DER of Category I, Category II, and Category III. For the overvoltage (OV) and undervoltage (UV) trip functions *clearing time* ranges and for the OV trip functions voltage ranges, the lower value is a limiting requirement (the setting shall not be set to lower values) and the upper value is a minimum requirement (the setting may be set above this value). For the UV trip functions voltage ranges, the upper value is a limiting requirement (the setting shall not be set to greater values) and the lower value is a minimum requirement (the setting may be set to lower values).[78] Area EPS operators may specify values within the specified range subject to the limitations on voltage trip settings specified by the *regional reliability coordinator*.[79, 80]

[77] When *clearing times* are less than 0.16 seconds greater than the specified *clearing time*, the provisions of 4.7 item b)1) are applicable.
[78] The following are recommendations for hardware design of equipment used to implement the trip functions by use of fixed 'ranges of adjustability': For the overvoltage (OV) and undervoltage (UV) trip functions *clearing time* ranges and for the OV trip functions voltage ranges, the lower value should be a limiting design requirement (the range of adjustability should not extend to lower values) and the upper value should be a minimum design requirement (the range of adjustability may be extended above this value). For the UV trip functions voltage ranges, the upper value should be a limiting design requirement (the range of adjustability should not extend to greater values) and the lower value should be a minimum design requirement (the range of adjustability may be extended to lower values).
[79] In North America, the limitations for transmission-connected resources as specified in NERC PRC-024-2 [B27] may be used for reference.
[80] The lower and upper values of the *ranges of allowable settings* for voltage and frequency trip settings specified in this standard for DER are not intended to limit the capabilities and settings of other equipment on the Area EPS. It is recommended that settings applied on Area EPS equipment conform to the voltage and frequency ride-through objectives of this standard whenever the Area EPS is in normal configuration. However, it is recognized that in certain cases Area EPS operators may need to occasionally and selectively use trip settings outside the *ranges of allowable settings* to accommodate worker safety practices or to safeguard distribution infrastructure while in an abnormal configuration, e.g., during automatic reconfiguration of a circuit section or temporary loss of direct transfer trip of mid- and large-scale DER. Area EPS operators should limit trip settings on Area EPS equipment that conflict with this standard to only affect those selective DER and Area EPS equipment and only for a limited period necessary to meet these worker safety and equipment protection goals. Area EPS operators should coordinate these practices with the *regional reliability coordinator* who may consider *bulk power system* impacts of affected aggregate DER capacity.

Table 11 —DER response (shall trip) to abnormal voltages for DER of abnormal operating performance Category I (see Figure H.7)

Shall trip—Category I				
Shall trip function	Default settings[a]		Ranges of allowable settings[b]	
	Voltage (p.u. of nominal voltage)	Clearing time (s)	Voltage (p.u. of nominal voltage)	Clearing time (s)
OV2	1.20	0.16	fixed at 1.20	fixed at 0.16
OV1	1.10	2.0	1.10–1.20	1.0–13.0
UV1	0.70	2.0	0.0–0.88	2.0–21.0
UV2	0.45	0.16	0.0–0.50	0.16–2.0

[a]The Area EPS operator may specify other voltage and *clearing time* trip settings within the *range of allowable settings*, e,g., to consider Area EPS protection coordination.

[b]Nominal system voltages stated in ANSI C84.1, Table 1 or as otherwise defined by the Area EPS operator. The *ranges of allowable settings* do not mandate a requirement for the DER to ride through this magnitude and duration of abnormal voltage condition. The Area EPS operator may specify the voltage thresholds and maximum *clearing times* within the *ranges of allowable settings*; settings outside of these ranges shall only be allowed as necessary for DER equipment protection and shall not conflict with the voltage disturbance ride through requirements specified in 6.4.2. For the overvoltage (OV) and undervoltage (UV) trip functions *clearing time* ranges and for the OV trip functions voltage ranges, the lower value is a limiting requirement (the setting shall not be set to lower values) and the upper value is a minimum requirement (the setting may be set above this value). For the UV trip functions voltage ranges, the upper value is a limiting requirement (the setting shall not be set to greater values) and the lower value is a minimum requirement (the setting may be set to lower values).

Table 12 —DER response (shall trip) to abnormal voltages for DER of abnormal operating performance Category II (see Figure H.8)

Shall trip—Category II				
Shall trip function	Default settings[a]		Ranges of allowable settings[b]	
	Voltage (p.u. of nominal voltage)	Clearing time (s)	Voltage (p.u. of nominal voltage)	Clearing time (s)
OV2	1.20	0.16	fixed at 1.20	fixed at 0.16
OV1	1.10	2.0	1.10–1.20	1.0–13.0
UV1	0.70	10.0	0.0–0.88	2.0–21.0
UV2	0.45	0.16	0.0–0.50	0.16–2.0

[a]The Area EPS operator may specify other voltage and *clearing time* trip settings within the *range of allowable settings*, e,g., to consider Area EPS protection coordination.

[b]Nominal system voltages stated in ANSI C84.1, Table 1 or as otherwise defined by the Area EPS operator. The *ranges of allowable settings* do not mandate a requirement for the DER to ride through this magnitude and duration of abnormal voltage condition. The Area EPS operator may specify the voltage thresholds and maximum *clearing times* within the *ranges of allowable settings*; settings outside of these ranges shall only be allowed as necessary for DER equipment protection and shall not conflict with the voltage disturbance ride through requirements specified in 6.4.2. For the overvoltage (OV) and undervoltage (UV) trip functions *clearing time* ranges and for the OV trip functions voltage ranges, the lower value is a limiting requirement (the setting shall not be set to lower values) and the upper value is a minimum requirement (the setting may be set above this value). For the UV trip functions voltage ranges, the upper value is a limiting requirement (the setting shall not be set to greater values) and the lower value is a minimum requirement (the setting may be set to lower values).

Table 13 —DER response (shall trip) to abnormal voltages for DER of abnormal operating performance Category III (see Figure H.9)

Shall trip—Category III				
Shall trip function	Default settings[a]		Ranges of allowable settings[b]	
	Voltage (p.u. of nominal voltage)	Clearing time (s)	Voltage (p.u. of nominal voltage)	Clearing time (s)
OV2	1.20	0.16	fixed at 1.20	fixed at 0.16
OV1	1.10	13.0	1.10–1.20	1.0–13.0
UV1	0.88	21.0	0.0–0.88	21.0–50.0
UV2	0.50	2.0	0.0–0.50	2.0–21.0

[a]The Area EPS operator may specify other voltage and *clearing time* trip settings within the *range of allowable settings*, e,g., to consider Area EPS protection coordination.

[b]Nominal system voltages stated in ANSI C84.1, Table 1 or as otherwise defined by the Area EPS operator. The *ranges of allowable settings* do not mandate a requirement for the DER to ride through this magnitude and duration of abnormal voltage condition. The Area EPS operator may specify the voltage thresholds and maximum *clearing times* within the *ranges of allowable settings*; settings outside of these ranges shall only be allowed as necessary for DER equipment protection and shall not conflict with the voltage disturbance ride-through requirements specified in 6.4.2. For the overvoltage (OV) and undervoltage (UV) trip functions *clearing time* ranges and for the OV trip functions voltage ranges, the lower value is a limiting requirement (the setting shall not be set to lower values) and the upper value is a minimum requirement (the setting may be set above this value). For the UV trip functions voltage ranges, the upper value is a limiting requirement (the setting shall not be set to greater values) and the lower value is a minimum requirement (the setting may be set to lower values).

6.4.2 Voltage disturbance ride-through requirements

6.4.2.1 General requirements and exceptions

The performance required of DER during voltage disturbances is specified in this clause. DER shall meet either the *abnormal operating performance* Category I, Category II, or Category III requirements of this clause, as specified by the Area EPS operator. The voltage disturbance ride-through requirements specified in this clause do not apply when frequency is outside of the ride-through range specified in 6.5.2.

DER shall be designed to provide the voltage disturbance ride-through capability specified in this clause without exceeding DER capabilities. Any tripping of the DER, or other failure to provide the specified ride-through capability, due to DER self-protection as a direct or indirect result of a voltage disturbance within a ride-through region, shall constitute non-compliance with this standard.

The DER shall specify its *abnormal operating performance category* within the nameplate information.

The voltage disturbance ride-through specified in the remainder of 6.4.2 shall not apply and DER may *cease to energize* the Area EPS and trip without limitations if any of the following applies:

a) The net active power exported across the *point of common coupling* into the Area EPS is continuously maintained at a value less than 10% of the aggregate rating of DER connected to the Local EPS prior to any voltage disturbance, and the Local EPS disconnects from the Area EPS, along with Local EPS load to intentionally form a Local EPS island, or

b) An active power demand of the Local EPS load equal or greater than 90% of the pre-disturbance aggregate DER active power output is shed within 0.1 s of when the DER ceases to energize the Area EPS and trips.

For voltage disturbances where the *applicable voltage* is outside the *ride-through operating region* parameters (voltage range and corresponding cumulative duration, minimum time) specified in Table 14 for *abnormal operating performance* Category I, Table 15 for Category II, or Table 16 for Category III, requirements for continued operation (ride-through), or *restore output* subsequent to the voltage disturbance, shall not apply.[81]

Table 14—Voltage ride-through requirements for DER for abnormal operating performance Category I (see Figure H.7)

Voltage range (p.u.)	Operating mode/response	Minimum ride-through time (s) (design criteria)	Maximum response time (s) (design criteria)
$V > 1.20$	Cease to Energize[a]	N/A	0.16
$1.175 < V \leq 1.20$	Permissive Operation	0.2	N/A
$1.15 < V \leq 1.175$	Permissive Operation	0.5	N/A
$1.10 < V \leq 1.15$	Permissive Operation	1	N/A
$0.88 \leq V \leq 1.10$	Continuous Operation	Infinite	N/A
$0.70 \leq V < 0.88$	Mandatory Operation	Linear slope of 4 s/1 p.u. voltage starting at 0.7 s @ 0.7 p.u.: $T_{\mathrm{VRT}} = 0.7\ \mathrm{s} + \frac{4\ \mathrm{s}}{1\ \mathrm{p.u.}}\left(V - 0.7\ \mathrm{p.u.}\right)$	N/A
$0.50 \leq V < 0.70$	Permissive Operation	0.16	N/A
$V < 0.50$	Cease to Energize[a]	N/A	0.16

[a]Cessation of current exchange of DER with Area EPS in not more than the maximum specified time and with no intentional delay. This does not necessarily imply disconnection, isolation, or a trip of the DER. This may include momentary cessation or trip.

Table 15—Voltage ride-through requirements for DER of abnormal operating performance Category II (see Figure H.8)

Voltage range (p.u.)	Operating mode/response	Minimum ride-through time (s) (design criteria)	Maximum response time (s) (design criteria)
$V > 1.20$	Cease to Energize[a]	N/A	0.16
$1.175 < V \leq 1.20$	Permissive Operation	0.2	N/A
$1.15 < V \leq 1.175$	Permissive Operation	0.5	N/A
$1.10 < V \leq 1.15$	Permissive Operation	1	N/A
$0.88 \leq V \leq 1.10$	Continuous Operation	Infinite	N/A
$0.65 \leq V < 0.88$	Mandatory Operation	Linear slope of 8.7 s/1 p.u. voltage starting at 3 s @ 0.65 p.u.: $T_{\mathrm{VRT}} = 3\ \mathrm{s} + \frac{8.7\ \mathrm{s}}{1\ \mathrm{p.u.}}\left(V - 0.65\ \mathrm{p.u.}\right)$	N/A
$0.45 \leq V < 0.65$	Permissive Operation	0.32	N/A
$0.30 \leq V < 0.45$	Permissive Operation	0.16	N/A
$V < 0.30$	Cease to Energize[a]	N/A	0.16

[a]Cessation of current exchange of DER with Area EPS in not more than the maximum specified time and with no intentional delay. This does not necessarily imply disconnection, isolation, or a trip of the DER. This may include momentary cessation or trip.

[81] Overvoltage and undervoltage events usually occur independently from each other, but may also be initiated by the same event (e.g., after clearing a fault, there may be an overvoltage event due to electromagnetic transients or system dynamic response). Thus, the high-voltage ride-through and the low-voltage ride-through requirements are based on cumulative durations and have to be interpreted independently from each other.

Table 16—Voltage ride-through requirements for DER of abnormal operating performance Category III (see Figure H.9)

Voltage range (p.u.)	Operating mode/response	Minimum ride-through time (s) (design criteria)	Maximum response time (s) (design criteria)
$V > 1.20$	Cease to Energize[a]	N/A	0.16
$1.10 < V \leq 1.20$	Momentary Cessation[b]	12	0.083
$0.88 \leq V \leq 1.10$	Continuous Operation	Infinite	N/A
$0.70 \leq V < 0.88$	Mandatory Operation	20	N/A
0.50[c] $\leq V < 0.70$	Mandatory Operation	10	N/A
$V < 0.50$[c]	Momentary Cessation[b]	1	0.083

[a]Cessation of current exchange of DER with Area EPS in not more than the maximum specified time and with no intentional delay. This does not necessarily imply disconnection, isolation, or a trip of the DER. This may include momentary cessation or trip.
[b]Temporarily cease to energize an EPS, while connected to the Area EPS, in response to a disturbance of the applicable voltages or the system frequency, with the capability of immediate restore output of operation when the applicable voltages and the system frequency return to within defined ranges.
[c]The voltage threshold between mandatory operation and momentary operation may be changed by mutual agreement between the Area EPS operator and DER operator, for example to allow the DER to provide Dynamic Voltage Support below 0.5 p.u.

6.4.2.2 Voltage disturbances within continuous operation region

Voltage disturbances of any duration, for which the *applicable voltage* as specified in 4.3 remains within Range B as defined by ANSI C84.1, shall not cause the DER to *cease to energize* and trip from the Area EPS. The DER shall remain in operation during any such disturbance, and shall continue to deliver *available active power* of magnitude at least as great as its pre-disturbance level of active power, prorated by the per-unit voltage level of the least phase voltage if that voltage is less than the nominal voltage.[82] Temporary deviations of active power having durations not exceeding 0.5 s shall be allowed.

Exception: Three-phase DER may cease to energize and trip if the negative sequence component of the applicable voltage is greater than 5% of the nominal voltage for greater than 60 s or greater than 3% of the nominal voltage for greater than 300 s, provided that the voltage imbalance is neither caused nor aggravated by unbalanced currents of the Local EPS.[83]

6.4.2.3 Low-voltage ride-through

6.4.2.3.1 General

For low-voltage ride-through, the relevant voltage at any given time shall be the least magnitude of the individual applicable phase-to-neutral, phase-to-ground, or phase-to-phase voltage relative to the corresponding nominal system voltage as specified in 4.3.

[82] Changes of active power are permitted in response to control commands in accordance with 4.6 or in response to other control settings.
[83] It should be noted that the equipment design requirements for continuous and short-time negative sequence current capabilities specified in IEEE Std C50.12 and IEEE Std C50.13 may not be sufficient for round rotor synchronous generators with ratings 10 MVA and larger or salient pole synchronous generators with ratings 5 MVA and larger to operate reliably in unbalanced *applicable voltage* conditions that may regularly occur in Area EPS governed by this standard. Note in 1.4 that this standard as a whole is not intended for, and is in part inappropriate for, application to energy resources connected to transmission or networked sub-transmission systems and that for DER interconnections that include individual synchronous generator units rated 10 MVA and greater, and where the requirements of this standard conflict with the requirements of IEEE Std C50.12 or IEEE Std C50.13, the requirements of IEEE Std C50.12 or IEEE Std C50.13, as relevant to the type of synchronous generator used, shall prevail.

6.4.2.3.2 Low-voltage ride-through capability

During temporary voltage disturbances, for which the *applicable voltage* on the phase that has the least voltage magnitude is less than the minimum of the *continuous operation region*, and within the corresponding voltage ranges and cumulative duration (minimum time) specified in Table 14 for Category I, Table 15 for Category II, and Table 16 for Category III, the DER shall be capable to ride-through and

- Shall maintain synchronism with the Area EPS.[84]
- Shall not *trip*.
- Shall restore output as specified in 6.4.2.7.

6.4.2.3.3 Low-voltage ride-through performance

During low-voltage ride-through, the DER shall operate in the following operating modes as specified in Table 14 for Category I, Table 15 for Category II, and Table 16 for Category III with the following requirements:

During temporary voltage disturbances, for which the *applicable voltage* on the phase that has the least voltage magnitude is within the *mandatory operation region*, the DER

- Shall maintain synchronism with the Area EPS.
- Shall continue to exchange current with the Area EPS.
- Shall neither *cease to energize* nor *trip*.

DER of Category II and Category III shall, by default, not reduce its total apparent current during the disturbance period in *mandatory operation mode* below 80% of the pre-disturbance value or of the corresponding active current level subject to the available active power, whichever is less, subject to the following:

- Active and reactive current oscillations that are positively damped are permitted during the disturbance and post-disturbance period.
- Transient apparent current magnitude changes having duration less than 30 ms, and dynamic current magnitude oscillations for which the mean value is greater than or equal to the pre-disturbance value constitute exceptions to this requirement.

By mutual agreement between the Area EPS operator and DER operator, other current characteristics may be specified.[85]

During temporary voltage disturbances, for which the *applicable voltage* on the phase that has the least voltage magnitude is within the *permissive operation region*, the DER

- Shall maintain synchronism with the Area EPS or shall not *trip*.
- May continue to exchange current with the Area EPS or may *cease to energize*.

[84] For all DER: maintain functioning of auxiliary equipment. For synchronous generation-based DER: maintain transient stability. For inverter-based DER: maintain “Current Angle Stability.” “Current Angle Stability” is the ability of a DER, which is grid-interfaced via a voltage source converter (VSC) and operated in parallel to the grid to inject current (magnitude, angle) for transiently changing grid conditions without violating the VSC synchronization methods’ stability zone.
[85] For example, dynamic voltage support as specified in 6.4.2.6 may be used within the *mandatory operating region*.

— If DER ceases to energize, shall restore output as specified in 6.4.2.7.

For Category III DER, during temporary voltage disturbances, for which the *applicable voltage* on the phase that has the least voltage magnitude is within the *momentary cessation operation region*, the DER

— Shall not *trip.*

— Shall *cease to energize.*

— Shall restore output as specified in 6.4.2.7.

6.4.2.4 High-voltage ride-through

6.4.2.4.1 General

For high-voltage ride-through, the relevant voltage at any given time shall be the greatest magnitude of the individual applicable phase-to-neutral, phase-to-ground or phase-to-phase voltage relative to the corresponding nominal system voltage as specified in 4.3.

6.4.2.4.2 High-voltage ride-through capability

During temporary voltage disturbances, for which the *applicable voltage* on the phase having the greatest voltage magnitude is greater than the maximum of the *continuous operation region*, and within the corresponding voltage ranges and cumulative duration (minimum time) specified in Table 14 for *abnormal operating performance* Category I, Table 15 for Category II, or Table 16 for Category III, the DER shall be capable to ride-through and

— Shall maintain synchronism with the Area EPS.[86]

— Shall not *trip.*

— Shall restore output as specified in 6.4.2.7.

6.4.2.4.3 High-voltage ride-through performance

During high-voltage ride-through, the DER shall operate in the following operating modes as specified in Table 14 for *abnormal operating performance* Category I, Table 15 for Category II, and Table 16 for Category III with the following requirements:

During temporary voltage disturbances, for which the *applicable voltage* on the phase having the greatest voltage magnitude is within the *permissive operating region*, the DER

— Shall maintain synchronism with the Area EPS or shall not *trip.*

— May continue to exchange current with the Area EPS or may *cease to energize.*

— If DER ceases to energize, shall restore output as specified in 6.4.2.7.

[86] For synchronous generation-based DER, maintain transient stability. For inverter-based DER, maintain control stability or “current angle stability.” For all DER, maintain functioning of auxiliary equipment.

For Category III DER, during temporary voltage disturbances, for which the *applicable voltage* on the phase having the greatest voltage magnitude is within the *momentary cessation operation region*, the DER

— Shall not *trip*.
— Shall *cease to energize*.
— Shall restore output as specified in 6.4.2.7.

6.4.2.5 Ride-through of consecutive voltage disturbances[87]

The requirements for continued operation (ride-through), or *restore output* shall apply to multiple consecutive voltage disturbances within a *ride-through operating region*, for which the voltage range and corresponding cumulative durations are specified in Table 14 for *abnormal operating performance* Category I, Table 15 for Category II, and Table 16 for Category III. These requirements are subject to the following provisions that specify conditions in Table 17 for which a DER may trip:[88]

a) For a set of consecutive disturbances in which voltages fall within a *ride-through operating region* multiple times, each interspersed by a period of voltage within the *continuous operation region* that has a duration no greater than specified in Table 17 Column 3 for the respective *performance category*, the cumulative duration of voltage within the respective *ride-through operating region* for all such disturbances shall be compared with the maximum required duration for the respective voltage disturbance severity. If this cumulative duration exceeds the required duration, the DER may trip.

b) If voltages remain entirely within the *continuous operation region* for a time period greater than specified in Table 17, Column 3 for the respective *performance category*, any further disturbance shall be considered as a new set of disturbances, and a new accumulation of ride-through duration as defined in item a) shall apply.

c) The DER shall not be required to ride through any more ride-through disturbance sets than the maximum number given in Table 17, Column 2 within the time period specified in Table 17, Column 4. Once a period-of-time as given in Table 17, Column 4 has passed since the last disturbance, the DER shall be required to ride through any new sets of disturbances as specified in item a) and item b).

Exception: DER shall be allowed to trip if the timing of multiple consecutive voltage disturbances during a specific event stimulate electromechanical oscillations to the degree where DER synchronism is lost or potential damage to the DER may occur.[89]

[87]The primary intent of voltage ride-through requirements for consecutive voltage disturbances is for DER to ride through a reasonable tripping and reclosing sequence associated with a short-circuit fault on a different portion of the Area EPS than that to which it is connected, but which causes these voltage disturbances at the DER. Other causes for consecutive disturbances are separate faults that might occur in a severe storm, or dynamic voltage swings that cyclically transition in and out of the *continuous operation* region.

[88]None of these provisions specifies that a DER shall trip for consecutive voltage disturbances. These provisions only specify conditions for which a DER may trip and is relieved of the mandatory requirement to ride through voltage disturbances. The ride-through of a DER for more than the specified number of disturbance sets (Column 2), for disturbance sets that are separated by less than the specified minimum time (Column 3), and disturbance sets occurring more frequently than the specified time window for new count (Column 4) does not pose a risk to the Area EPS, and DER should ride through as many disturbance sets as they are capable.

[89]It should be noted that IEEE Std C50.13 provides assessment criteria for a site-specific study of torsional stress for synchronous generators with ratings 10 MVA and larger. Per 1.4, this standard as a whole is not intended for, and is in part inappropriate for, application to energy resources connected to transmission or networked sub-transmission systems and for DER interconnections that include individual synchronous generator units rated 10 MVA and greater, and where the requirements of this standard conflict with the requirements of IEEE Std C50.12 or IEEE Std C50.13, the requirements of IEEE Std C50.12 or IEEE Std C50.13, as relevant to the type of synchronous generator used, shall prevail.

Table 17 —Voltage ride-through requirements for consecutive temporary voltage disturbances caused by unsuccessful reclosing for DER of abnormal operating performance Category I, Category II, and Category III

Col. 1	Col. 2	Col. 3	Col. 4
Category	**Maximum number of ride-through disturbance sets**	**Minimum time between successive disturbance sets (s)**	**Time window for new count of disturbance sets (min)**
I	2	20.0	60
II	2	10.0	60
III	3	5.0	20

6.4.2.6 Dynamic voltage support

Dynamic voltage support[90] from DER can support the *applicable voltage* by supplying the Area EPS with a current[91] during low-voltage ride-through and high-voltage ride-through operation. Alternate means of DER control and designs can exist to provide dynamic voltage support. Support of the *applicable voltage* can provide benefits to the Area EPS and BPS.

6.4.2.6.1 Dynamic voltage support capability

Any DER may have the capability of *dynamic voltage support* during low-voltage ride-through and high-voltage ride-through.

6.4.2.6.2 Dynamic voltage support performance

The *dynamic voltage support* capability may be utilized during *mandatory operation* or *permissive operation* under a mutual agreement with the Area EPS operator[92] considering both the capability and the DER-specific implementation of the dynamic voltage support function. The DER shall maintain synchronism with the Area EPS and may provide *dynamic voltage support* to the Area EPS during and following temporary voltage disturbances, for which the *applicable voltage* on any phase is as follows:

a) Less than the minimum of the *continuous operation* region and within either the *mandatory operation* or the *permissive operation* region, or

b) Greater than the maximum of the *continuous operation* region and within the *permissive operation region*.

The *dynamic voltage support* shall not cause the DER to *cease to energize* in situations where the DER would not *cease to energize* without the *dynamic voltage support*.[93]

[90] *Dynamic voltage support* provides rapid reactive power exchanges during voltage excursions. *Dynamic voltage support* may provide better voltage stability in the distribution system during transient events extending into voltage ride-through or high-voltage ride-through regions. Valuable information on the preferable characteristics of current injected to the Area EPS as dynamic voltage support is provided in Boemer [B3].
[91] The relative effectiveness active and reactive current of the dynamic voltage support can depend on the *X/R* ratio of the Area EPS.
[92] The Area EPS operator may consider the impact of a *dynamic voltage support* from DER on the Area EPS protection.
[93] The implementation (design, testing and conformance, communications, etc.) of the *dynamic voltage support* is recommended to have adequate capability to prevent the creation of overvoltage in any phases of the *applicable voltages* when providing *dynamic voltage support* for any types of faults (balanced and unbalanced), for which the overvoltage would not occur without the DER.

6.4.2.7 Restore output with voltage ride-through

6.4.2.7.1 Restore output without dynamic voltage support

If the DER rides through a voltage disturbance without trip and the DER does not provide *dynamic voltage support* (see 6.4.2.6) while in a *mandatory operation* or *permissive operation* region, once the *applicable voltage* surpasses the lower value of the *mandatory operation* region during low-voltage ride-through or the *applicable voltage* returns below the upper value of the *continuous operation* region during high-voltage ride-through, the DER

— Shall maintain synchronism with the Area EPS.

— Shall *restore output* of active current to at least 80% of pre-disturbance active current level within 0.4 s. Active and reactive current oscillations in the post-disturbance period that are positively damped are acceptable.

6.4.2.7.2 Restore output with dynamic voltage support

If the DER rides through a voltage disturbance without trip and the DER provides *dynamic voltage support* while in a *mandatory operation* or *permissive operation* region, once the *applicable voltage* enters the *continuous operation region*, the DER

— Shall maintain synchronism with the Area EPS.

— Shall continue to provide *dynamic voltage support* up to 5 s after the *applicable voltage* surpasses the lower value of the *continuous operation region* and *restore output* of active current to at least 80% of pre-disturbance active current level or to the available active current subject to reactive current priority, whichever is less, within 0.4 s.

— Shall discontinue providing *dynamic voltage support* 5 s after the *applicable voltage* surpasses the lower value of the continuous operation region and resume reactive power functionality for normal conditions as defined in 4.2 for the mode that has been selected.

6.4.2.7.3 Transition between performance operating regions for Category III DER

If the RPA of a Category III DER is the PCC, the requirement for transitioning between *momentary cessation* and *mandatory operation* or *momentary cessation* and *continuous operation*, may optionally be based on the voltage measured at the PoC. When this optionality is excercised, the *momentary cessation* threshold shall be adjusted[94] for the predicted voltage difference between the PCC and PoC, such that the performance of the DER approximates the defined performance based on PCC voltage. This option does not apply to Category I and Category II DER.[95]

[94] The capability to adjust the momentary cessation threshold may be mutually agreed upon between the Area EPS Operator in coordination with the *regional reliability coordinator* and the DER Operator and may otherwise be exempt from the interoperability management information requirements in 10.6.

[95] Because Category I and Category II have permissive operating regions at voltages somewhat less than the lower limit of the *mandatory operation region*, this option is not necessary.

6.5 Frequency

6.5.1 Mandatory frequency tripping requirements

When the system frequency is in a range given in Table 18, and the fundamental-frequency component of voltage on any phase is greater than 30% of nominal, the DER shall *cease to energize* the Area EPS and *trip* within a *clearing time* as indicated.[96] Under and overfrequency tripping thresholds and *clearing times* shall be adjustable over the *ranges of allowable settings* specified in Table 18. The underfrequency and overfrequency trip settings shall be specified by the Area EPS operator in coordination with the requirements of the *regional reliability coordinator*. If the Area EPS operator does not specify any settings, the default settings shall be used.

The frequency and time set points shall be field adjustable and may be remotely adjustable per the interoperability requirements specified in Clause 10.

The *ranges of allowable settings* do not mandate a requirement for the DER to ride through this magnitude and duration of abnormal frequency condition. The Area EPS operator may specify the frequency thresholds and maximum *clearing times* within the *ranges of allowable settings*; settings outside of these ranges shall only be allowed as necessary for DER equipment protection and shall not conflict with the frequency disturbance ride-through requirements specified in 6.5.2.

Two overfrequency trip functions, OF1 and OF2, and two underfrequency trip functions, UF1 and UF2 apply simultaneously. For the overfrequency (OF) and underfrequency (UF) trip functions *clearing time* ranges and for the OF trip functions frequency ranges, the lower value is a limiting requirement (the setting shall not be set to lower values) and the upper value is a minimum requirement (the setting may be set above this value). For the UF trip functions frequency ranges, the upper value is a limiting requirement (the setting shall not be set to greater values) and the lower value is a minimum requirement (the setting may be set to lower values).[97] Area EPS operators may specify values within the specified range subject to the limitations on frequency trip settings specified by the *regional reliability coordinator*.[98, 99]

[96] When *clearing times* are less than 0.16 seconds greater than the specified *clearing time*, the provisions of 4.7 b)1) are applicable.

[97] The following are recommendations for hardware design of equipment used to implement the trip functions by use of fixed 'ranges of adjustability': For the overfrequency (OF) and underfrequency (UF) trip functions *clearing time* ranges and for the OF trip functions frequency ranges, the lower value should be a limiting design requirement (the range of adjustability should not extend to lower values) and the upper value should be a minimum design requirement (the range of adjustability may be extended above this value). For the UF trip functions frequency ranges, the upper value should be a limiting design requirement (the range of adjustability should not extend to greater values) and the lower value should be a minimum design requirement (the range of adjustability may be extended to lower values).

[98] In North America, the limitations for transmission-connected resources as specified in NERC PRC-024-2 [B27] may be used for reference.

[99] The lower and upper values of the *ranges of allowable settings* for voltage and frequency trip settings specified in this standard for DER are not intended to limit the capabilities and settings of other equipment on the Area EPS. It is recommended that settings applied on Area EPS equipment conform to the voltage and frequency ride-through objectives of this standard whenever the Area EPS is in normal configuration. However, it is recognized that in certain cases Area EPS operators may need to occasionally and selectively use trip settings outside the *ranges of allowable settings* to accommodate worker safety practices or to safeguard distribution infrastructure while in an abnormal configuration, e.g., during automatic reconfiguration of a circuit section or temporary loss of direct transfer trip of mid- and large-scale DER. Area EPS operators should limit trip settings on Area EPS equipment that conflict with this standard to only affect those selective DER and Area EPS equipment and only for a limited period necessary to meet these worker safety and equipment protection goals. Area EPS operators should coordinate these practices with the *regional reliability coordinator* who may consider *bulk power system* impacts of affected aggregate DER capacity.

Table 18—DER response (shall trip) to abnormal frequencies for DER of abnormal operating performance Category I, Category II, and Category III (see Figure H.10)

Shall trip function	Default settings[a]		Ranges of allowable settings[b]	
	Frequency[c] (Hz)	Clearing time (s)	Frequency (Hz)	Clearing time (s)
OF2	62.0	0.16	61.8–66.0	0.16–1 000.0
OF1	61.2	300.0	61.0–66.0	180.0–1 000.0
UF1	58.5	300.0[c]	50.0–59.0	180.0–1 000
UF2	56.5	0.16	50.0–57.0	0.16–1 000

[a]The frequency and *clearing time* set points shall be field adjustable. The actual applied underfrequency (UF) and overfrequency (OF) trip settings shall be specified by the Area EPS operator in coordination with the requirements of the *regional reliability coordinator*. If the Area EPS operator does not specify any settings, the default settings shall be used.

[b]The *ranges of allowable settings* do not mandate a requirement for the DER to ride through this magnitude and duration of abnormal frequency condition. The Area EPS operator may specify the frequency thresholds and maximum *clearing times* within the *ranges of allowable settings*; settings outside of these ranges shall only be allowed as necessary for DER equipment protection and shall not conflict with the frequency disturbance ride through requirements specified in 6.5.2. For the overfrequency (OF) and underfrequency (UF) trip functions *clearing time* ranges and for the OF trip functions frequency ranges, the lower value is a limiting requirement (the setting shall not be set to lower values) and the upper value is a minimum requirement (the setting may be set above this value). For the UF trip functions frequency ranges, the upper value is a limiting requirement (the setting shall not be set to greater values) and the lower value is a minimum requirement (the setting may be set to lower values).

[c]This time shall be chosen to coordinate with typical regional underfrequency load shedding programs and expected frequency restoration time.

6.5.2 Frequency disturbance ride-through requirements

6.5.2.1 General requirements and exceptions

The performance required of DER during frequency disturbances is specified in this clause. DER shall meet one of the *abnormal operating performance* Category I, Category II, or Category III of this clause. The frequency disturbance ride-through requirements specified in this clause do not apply when voltage is outside of the ride-through range specified in 6.4.2.

DER shall be designed to provide the frequency disturbance ride-through capability specified in this clause without exceeding DER capabilities. Any tripping of the DER, or other failure to provide the specified ride-through capability, due to DER self-protection as a direct or indirect result of a frequency disturbance within a ride-through region, shall constitute non-compliance with this standard.

The DER shall specify its *abnormal operating performance category* within the nameplate information.

The frequency disturbance ride-through specified in the remainder of 6.5.2 shall not apply and DER may *cease to energize* the Area EPS and trip without limitations if any of the following applies:

a) The net active power exported[100] across the *point of common coupling* into the Area EPS is continuously maintained at a value less than 10% of the aggregate rating of DER connected to the Local EPS prior to any frequency disturbance, and the Local EPS disconnects from the Area EPS, along with Local EPS load to intentionally form a Local EPS island, or

[100] Energy Storage DER operating in a manner that modulates active power, i.e., importing and exporting active power, shall be evaluated for this exception based solely on the maximum positive power point over the modulated power range.

b) An active power demand of the Local EPS load equal or greater than 90% of the pre-disturbance aggregate DER active power output is shed within 0.1 s of when the DER ceases to energize the Area EPS and trips.

For frequency disturbances outside the ride-through operating region parameters (frequency range and corresponding cumulative duration, minimum time) specified in Table 19 for Category I, Category II, and Category III, requirements for continued operation (ride-through), or *restore output* subsequent to the frequency disturbance, shall not apply.[101]

Table 19—Frequency ride-through requirements for DER of abnormal operating performance Category I, Category II, and Category III (see Figure H.10)

Frequency range (Hz)	Operating mode	Minimum time (s) (design criteria)
$f > 62.0$	No ride-through requirements apply to this range	
$61.2 < f \leq 61.8$	Mandatory Operation[a]	299
$58.8 \leq f \leq 61.2$	Continuous Operation[a,b]	Infinite[c]
$57.0 \leq f < 58.8$	Mandatory Operation[b]	299
$f < 57.0$	No ride-through requirements apply to this range	

[a]Any DER shall provide the frequency-droop (frequency-power) operation for high-frequency conditions specified in 6.5.2.7.
[b]DER of Category I may provide the frequency-droop (frequency-power) operation for low-frequency conditions specified in 6.5.2.7. DER of Category II or Category III shall provide the frequency-droop (frequency-power) operation for low-frequency conditions specified in 6.5.2.7.
[c]For a per-unit ratio of Voltage/frequency limit of $V/f \leq 1.1$.

6.5.2.2 Frequency disturbances within continuous operation region

Frequency disturbances of any duration, for which the system frequency remains between 58.8 Hz and 61.2 Hz and the per-unit ratio of Voltage/frequency is less than or equal to 1.1, shall not cause the DER to trip. The DER shall remain in operation during any such disturbance, and shall be able to continue to exchange active power at least as great as its pre-disturbance level of power.

6.5.2.3 Low-frequency ride-through

6.5.2.3.1 Low-frequency ride-through capability

During temporary frequency disturbances, for which the system frequency is less than 58.8 Hz and greater than or equal to 57.0 Hz, and having a cumulative duration below 58.8 Hz of less than 299 s in any ten-minute period, the DER shall be capable to ride-through and

— Shall maintain synchronism with the Area EPS.

— Shall not reduce its active power output below the value specified in Table 20, depending on the DER *performance category* as described in Clause 4. Reductions of *available active power* due to the underfrequency event shall not be allowed when the voltage is within the continuous operating range. Active power may be reduced in proportion with the grid voltage when the grid voltage is below the level for *continuous operation*.

[101] This standard may be adopted by AGIRs with frequency values defining frequency ride-through performance in the *continuous operation* region and *mandatory operation* region other than the ones specified.

Table 20—Frequency ride-through requirements for active power output capability for abnormal operating performance Category I, Category II, and Category III

Category	Active power output capability
I	80% of nameplate active power rating or the pre-disturbance active power output whichever is less
II and III	Pre-disturbance active power output
NOTE—Per 6.1, this requirement is limited to *available active power*.	

6.5.2.3.2 Low-frequency ride-through performance

During low-frequency ride-through, the DER shall operate in the *mandatory operation* region as specified in Table 19 for *abnormal operating performance* Category I, Category II, and Category III with the following requirements:

During temporary frequency disturbances, for which the system frequency is within the *mandatory operation* region, the DER

— Shall maintain synchronism with the Area EPS.

— Shall continue to exchange pre-disturbance current with the Area EPS subject to limitations specified in Table 20 and shall neither *cease to energize* nor *trip*. Active and reactive current oscillations that are positively damped are acceptable.

— Shall, as applicable, modulate active power to mitigate the underfrequency conditions as specified in Table 22, depending on the DER *performance category* as described in Clause 4. Neither provision of energy storage capability, nor operation of DER at power outputs less than the power available in order to allow reserve for power increase in response to underfrequency (pre-curtailment), are requirements of this standard.[102]

6.5.2.4 High-frequency ride-through

6.5.2.4.1 High-frequency ride-through capability

During temporary frequency disturbances, for which the system frequency is greater than 61.2 Hz and less than or equal to 61.8 Hz, and having a cumulative duration greater than 61.2 Hz of less than 299 s in any ten-minute period, the DER shall be capable to ride-through and shall maintain synchronism with the Area EPS.

6.5.2.4.2 High-frequency ride-through performance

During high-frequency ride-through, the DER shall operate in *mandatory operation* region as specified in Table 19 for *abnormal operating performance* Category I, Category II, and Category III with the following requirements:

During temporary frequency disturbances, for which the system frequency is within the *mandatory operation* region, the DER

[102] Pre-curtailment or other measures to provide frequency response reserve may be included in contractual agreements and interconnection agreements, which are outside the scope of this standard. The intent of the requirement in this standard is for the DER to only have the control capability in the DER to provide frequency response when the reserve exists, either due to specific contractual arrangements, dispatch control, or when curtailment exists for other reasons. Direction of active power can be negative (charging) for Energy Storage DER, e.g., return to frequency reduction via charging through droop or dispatch control, if operating for that purpose prior to trip.

— Shall maintain synchronism with the Area EPS.

— Shall continue to exchange current with the Area EPS and shall neither *cease to energize* nor *trip.*

— Shall modulate active power to mitigate the overfrequency conditions.

6.5.2.5 Rate of change of frequency (ROCOF) ride-through

Within the *continuous operation region* and the low-frequency and high-frequency ride-through operating regions (frequency range and corresponding cumulative duration, minimum time), the DER shall ride through and shall not trip for frequency excursions having magnitudes of rates of change of frequency (ROCOF) that are less than or equal to the values specified in Table 21 per *abnormal operating performance category*.[103] As specified in 4.3, the ROCOF shall be the average rate of change of frequency over an averaging window of at least 0.1 s.

Table 21 —Rate of change of frequency (ROCOF) ride-through requirements for DER of abnormal operating performance Category I, Category II, and Category III

Category I	Category II	Category III
0.5 Hz/s	2.0 Hz/s	3.0 Hz/s

6.5.2.6 Voltage phase angle changes ride-through

Multi-phase DER shall ride through for positive-sequence phase angle changes within a sub-cycle-to-cycle time frame of the *applicable voltage* of less than or equal to 20 electrical degrees. In addition, multi-phase DER shall remain in operation for change in the phases angle of individual phases less than 60 electrical degrees, provided that the positive sequence angle change does not exceed the forestated criterion. Single-phase DER shall remain in operation for phase angle changes within a sub-cycle-to-cycle time frame of the *applicable voltage* of less than or equal to 60 electrical degrees. Active and reactive current oscillations in the post-disturbance period that are positively damped or momentary cessation of the DER having a maximum duration of 0.5 s shall be acceptable in response to phase angle changes.

6.5.2.7 Frequency-droop (frequency-power)

6.5.2.7.1 Frequency-droop (frequency-power) capability

Depending on the DER *abnormal operating performance category* as described in Clause 4, the DER shall have the capability of *mandatory operation* with frequency-droop (frequency-power) during *low-frequency ride-through* and *high-frequency ride-through* as specified in Table 22.

[103] The values specified in Table 21 are intended for DER to withstand frequency disturbances that can occur in interconnected bulk power systems. Frequency disturbances during conditions where the bulk power system has split into multiple islands can have much larger ROCOF values than specified here.

Table 22—Requirements of a frequency-droop (frequency-power) operation for low-frequency conditions and high-frequency conditions for DER of abnormal operating performance Category I, Category II, and Category III

Category	Operation for low-frequency conditions	Operation for high-frequency conditions
I	Optional (may)	Mandatory (shall)
II	Mandatory (shall)	Mandatory (shall)
III	Mandatory (shall)	Mandatory (shall)

6.5.2.7.2 Frequency-droop (frequency-power) operation

During temporary frequency disturbances, for which the system frequency is outside the adjustable deadband db_{OF} and db_{UF} as specified in Table 24, but still between the trip settings in Table 18, the DER shall adjust its active power output from the pre-disturbance levels, according to the formulas in Table 23. The active power output shall be as defined by the relevant formula in Table 23, plus any inertial response to the rate of change of frequency, until frequency returns to within the deadband.

The DER response shall conform to the prioritization of DER responses specified in 4.7.

Figure H.7 shows three example curves of a frequency-droop function for which the DER is operating at different pre-disturbance levels of nameplate rating. A DER response during low-frequency conditions may be subject to *available active power* and the pre-disturbance dispatch level.

Table 23—Formula for frequency-droop (frequency-power) operation for low-frequency conditions and high-frequency conditions for DER for all performance categories

Operation for low-frequency conditions	Operation for high-frequency conditions
$p = \min\limits_{f<60-db_{UF}} \left\{ p_{pre} + \frac{(60-db_{UF})-f}{60 \cdot k_{UF}}; p_{avl} \right\}$	$p = \max\limits_{f>60+db_{OF}} \left\{ p_{pre} + \frac{f-(60+db_{OF})}{60 \cdot k_{OF}}; p_{min} \right\}$

where

- p is the active power output,[104] in p.u. of the DER nameplate active power rating
- f is the disturbed system frequency in Hz
- p_{avl} is the *available active power*, in p.u. of the DER rating
- p_{pre} is the pre-disturbance active power output, defined by the active power output at the point of time the frequency exceeds the deadband, in p.u. of the DER rating
- p_{min} is the minimum active power output due to DER prime mover constraints, in p.u. of the
- db_{OF} is a single-sided deadband value for high-frequency and low-frequency, respectively, in Hz
- db_{UF} is a single-sided deadband value for high-frequency and low-frequency, respectively, in Hz
- k_{OF} is the per-unit frequency change corresponding to 1 per-unit power output change (frequency droop), unitless
- k_{UF} is the per-unit frequency change corresponding to 1 per-unit power output change (frequency droop), unitless

Adjustments to db_{OF}, db_{UF}, k_{OF}, k_{UF}, and $T_{\text{response (small-signal)}}$ shall be permitted in coordination with the Area EPS operator and the requirements of the *regional reliability coordinator*.

[104] Includes positive and negative active power for Energy Storage DER during low- and high-frequency conditions respectively. Use of alternate control means to meet this requirement is permitted.

Table 24 —Parameters of frequency-droop (frequency-power) operation for DER of abnormal operating performance Category I, Category II, and Category III

Parameter	Default settings[a]			Ranges of allowable settings[b]		
	Category I	Category II	Category III	Category I	Category II	Category III
db_{OF}, db_{UF} (Hz)	0.036	0.036	0.036	0.017[c]–1.0	0.017[c]–1.0	0.017[c]–1.0
k_{OF}, k_{UF}	0.05	0.05	0.05	0.03–0.05	0.03–0.05	0.02–0.05
$T_{response\ (small\text{-}signal)}$ (s)	5	5	5	1–10	1–10	0.2–10

[a]Adjustments shall be permitted in coordination with the Area EPS operator.

[b]For the single-sided deadband values (db_{OF}, db_{UF}) ranges, both the lower value and the upper value is a minimum requirement (wider settings shall be allowed). For the frequency droop values (k_{OF}, k_{UF}) ranges, the lower value is a limiting requirement (the setting shall not be set to lower values) and the upper value is a minimum requirement (the setting may be set to greater values). For the open-loop response time, $T_{response\ (small\text{-}signal)}$, the upper value is a limiting requirement (the setting shall not be set to greater values) and the lower value is a minimum requirement (the setting may be set to lower values). Any settings different from the default settings in Table 24 shall be approved by the *regional reliability coordinator* with due consideration of system dynamic oscillatory behavior.

[c]A deadband of less than 0.017 Hz shall be permitted.

The time performance of the frequency-droop (frequency/power) operation for all three DER Performance Categories as described in Clause 4 shall have the following characteristics:

a) Small-signal performance (a frequency deviation resulting in a power change of less than 5% of Rated Active Power): the open-loop response time $T_{response\ (small\text{-}signal)}$ of the DER shall be adjustable within the ranges specified in Table 24. If the Area EPS operator does not specify any settings, the default setting shall be 5 s. Any settings different from the default settings in Table 24 shall be approved by the *regional reliability coordinator* with due consideration of system dynamic oscillatory behavior.

b) Large-signal performance (a frequency deviation resulting in a power change of equal to or greater than 5% of Rated Active Power): The DER shall not be required to change its active power output at a rate greater than 20% of nameplate rating per minute, in order to meet the minimum response requirement, if the Primary Energy Source is physically unable to provide a greater response rate.[105]

6.5.2.8 Inertial response

Inertial response, in which the DER active power is varied in proportion to the rate of change of frequency, is not required but is permitted.[106]

6.6 Return to service after trip

The Return to Service criteria for DER of Category I, Category, II, and Category III are specified in 4.10.

[105] The maximum available power ramp rate of the DER shall be as fast as technically feasible, and equal or greater than the minimum 20% per minute ramping capability requirement. This waiver of the minimum time requirement shall only apply for frequency changes of sufficient magnitude and rate of change so as to otherwise exceed the DER's power ramping capability.

[106] If Area EPS Operator and DER Operator mutually agree to use DER inertial response, the performance requirements should be coordinated with the *regional reliability coordinator* with due consideration of system dynamic oscillatory behavior.

7. Power quality

Refer to the informative Annex G for additional information regarding DER induced power quality phenomena, measurement, grid interactions, and planning levels.

7.1 Limitation of dc injection

The DER shall not inject dc current greater than 0.5% of the full rated output current at the reference point of applicability (RPA).

7.2 Limitation of voltage fluctuations induced by the DER

7.2.1 General

The DER shall not create unacceptable rapid voltage changes or flicker at the point of common coupling (PCC).

7.2.2 Rapid voltage changes (RVC)

When the PCC is at medium voltage, the DER shall not cause step or ramp changes in the RMS voltage at the PCC exceeding 3% of nominal and exceeding 3% per second averaged over a period of one second. When the PCC is at low voltage, the DER shall not cause step or ramp changes in the RMS voltage exceeding 5% of nominal and exceeding 5% per second averaged over a period of one second. Any exception to the limits is subject to approval by the Area EPS operator with consideration of other sources of RVC within the Area EPS.

These RVC limits shall apply to sudden changes due to frequent energization of transformers, frequent switching of capacitors or from abrupt output variations caused by DER misoperation. These RVC limits shall not apply to infrequent events such as switching, unplanned tripping, or transformer energization related to commissioning, fault restoration, or maintenance.[107]

[107] Subclause 7.2.2 is not intended to address issues associated with slow voltage variations, which can be caused by cloud shadow passage, wind speed changes, etc.

7.2.3 Flicker

The DER contribution (emission values) to the flicker, measured at the PCC, shall not exceed the greater of the limits listed in Table 25 and the individual emission limits defined by IEC/TR 61000-3-7. Any exception to the limits shall be approved by the Area EPS operator with consideration of other sources of flicker within the Area EPS.

Table 25—Minimum individual DER flicker emission limits[a]

E_{Pst}	E_{Plt}
0.35	0.25

[a]95% probability value should not exceed the emission limit based on a one week measurement period.

Assessment and measurement methods for flicker are defined in IEEE Std 1453 and IEC/TR 61000-3-7. In addition, the following shall apply:

— Equipment other than a DER shall be allowed to mitigate the flicker induced by a DER.

— E_{Pst} is the emission limit for the short-term flicker severity, P_{st} If not specified differently, the P_{st} evaluation time is 600 s.

— E_{Plt} is the emission limit for long-term flicker severity, $P_{\mathrm{lt.}}$ If not specified differently, the P_{lt} evaluation time is 2 h.

— P_{lt} can be calculated by using Equation (1).

$$P_{lt} = \sqrt[3]{\frac{1}{12}\sum_{i=1}^{12} P_{st_i}^3} \tag{1}$$

where (i = 1, 2, 3, ...) are consecutive readings of the short-term severity P_{st}

7.3 Limitation of current distortion

Harmonic current distortion, inter-harmonic current distortion, and total rated-current distortion (TRD) at the *reference point of applicability* (RPA) shall not exceed the limits stated in the following paragraph and in Table 26 and Table 27.

The methodology for measuring harmonic and inter-harmonic values in this requirement is defined in IEEE Std 519.[108] Note that Table 26 and Table 27 differ from any table in IEEE Std 519. In this standard, the new term "Total Rated-current Distortion (TRD)" was introduced and used instead of TDD (in Table 26) and the even order current distortion limits above the second order are relaxed for DER (in Table 27).

Any aggregated harmonics current distortion between $h \pm 5$ Hz, where h is the individual harmonic order, shall be limited to the associated harmonic order h limit in Table 26 and Table 27. Any aggregated inter-harmonics current distortion between $h + 5$ Hz and $(h + 1) - 5$ Hz shall be limited to the lesser magnitude limit of h and $h + 1$ harmonic order in Table 26 and Table 27.

[108] IEEE Std 519 requires that the harmonic h be calculated as the root-sum-square of the spectral component value at the actual integer multiple of the fundamental frequency and spectral components in the adjacent ± 5 Hz bins from the gapless 10/12 cycle (approximately 200 ms) measurement window. All of the other 5 Hz bins spectral components are similarly combined using root-sum-square into the inter-harmonic value between adjacent harmonics.

These current distortion limits shall be exclusive of any harmonic currents due to harmonic voltage distortion present in the Area EPS without the DER connected. Upon mutual agreement between the Area EPS operator and the DER operator the DER may inject current distortion in excess of these tables, such as when it is used as an active filtering device.

Table 26—Maximum odd harmonic current distortion in percent of rated current (I_{rated})[a]

Individual odd harmonic order h	$h < 11$	$11 \leq h < 17$	$17 \leq h < 23$	$23 \leq h < 35$	$35 \leq h < 50$[109]	Total rated current distortion (TRD)
Percent (%)	4.0	2.0	1.5	0.6	0.3	5.0

[a]I_{rated} = the DER unit rated current capacity (transformed to the RPA when a transformer exists between the DER unit and the RPA).

Table 27—Maximum even harmonic current distortion in percent of rated current (I_{rated})[a]

Individual even harmonic order h	$h = 2$	$h = 4$	$h = 6$	$8 \leq h < 50$
Percent (%)	1.0	2.0	3.0	Associated range specified in Table 26

[a]I_{rated} = the DER unit rated current capacity (transformed to the RPA when a transformer exists between the DER unit and the RPA).

The total rated current distortion (TRD) in Table 26 , which includes the harmonic distortion and inter-harmonic distortion, can be calculated using Equation (2):

$$\%TRD = \frac{\sqrt{I_{rms}^2 - I_1^2}}{I_{rated}} \times 100\% \qquad (2)$$

where

I_1 is the fundamental current as measured at the RPA
I_{rated} is the DER rated current capacity (transformed to the RPA when a transformer exists between the DER unit and the RPA)
I_{rms} is the root-mean-square of the DER current, inclusive of all frequency components, as measured at the RPA

7.4 Limitation of overvoltage contribution

7.4.1 Limitation of overvoltage over one fundamental frequency period

The DER shall not contribute to instantaneous or fundamental frequency overvoltages with the following limits:

a) The DER shall not cause the fundamental frequency line-to-ground voltage on any portion of the Area EPS that is designed to operate effectively grounded, as defined by IEEE Std C62.92.1, to exceed 138% of its nominal line-to-ground fundamental frequency voltage for a duration exceeding one fundamental frequency period.

[109] Typical utility instrument transformers may not be able to accurately reproduce high order harmonic content. Adherence to the higher order harmonics may need to be confirmed in a laboratory setting or, if in the field, using equipment designed for use at the frequencies in question. Refer to Annex G for more information.

b) The DER shall not cause the line-to-line fundamental frequency voltage on any portion of the Area EPS to exceed 138% of its nominal line-to-line fundamental frequency voltage for a duration exceeding one fundamental frequency period.

7.4.2 Limitation of cumulative instantaneous overvoltage

The DER shall not cause the instantaneous voltage on any portion of the Area EPS to exceed the magnitudes and cumulative durations shown in Figure 3. The cumulative duration shall only include the sum of durations for which the instantaneous voltage exceeds the respective threshold over a one-minute time window.[110]

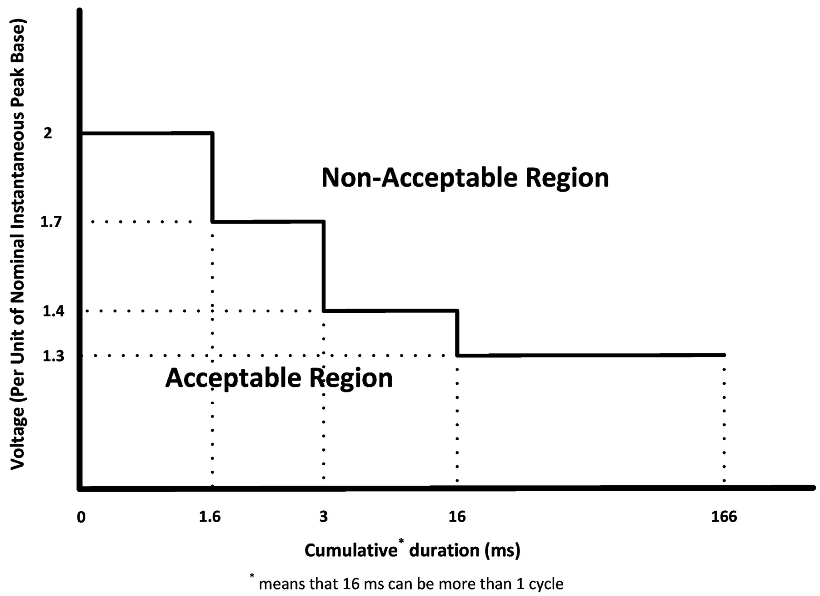
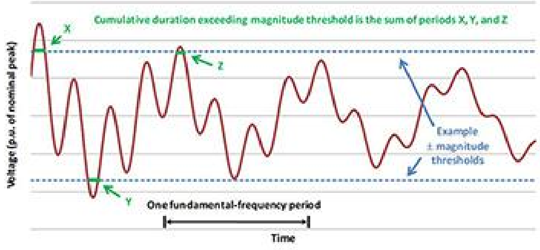


Figure 3 —Transient overvoltage limits

[110] Cumulative duration is illustrated as follows:



8. Islanding

8.1 Unintentional islanding

8.1.1 General

For an *unintentional island* in which the DER energizes a portion of the Area EPS through the PCC, the DER shall detect the island, *cease to energize* the Area EPS, and trip within 2 s of the formation of an island.[111] False detection of an *unintentional island* that does not actually exist shall not justify non-compliance with ride-through requirements as specified in Clause 6.

8.1.2 Conditional extended clearing time

Upon mutual agreement between the Area EPS operator and the DER operator, the *clearing time* may be extended from 2 s to as much as 5 s.[112]

8.1.3 Area EPS with automatic reclosing

Requirements with regard to Area EPS automatic reclosing coordination are specified in 6.3.[113]

8.2 Intentional islanding

8.2.1 General

An intentional island can be an intentional Area EPS island or an intentional Local EPS island. The requirements in 8.2 apply to both.

An *intentional island* that includes any portion of the Area EPS is an *intentional Area EPS island*. An *intentional Area EPS island*, while islanded, shall be designed and operated in coordination with the Area EPS operator.

An *intentional island* that is totally within the bounds of a Local EPS is an *intentional Local EPS island*.[114] DER that support *intentional Local EPS islands*, while interconnected to an Area EPS that is not islanded, shall be subject to all requirements for interconnection of DER to Area EPS specified in Clause 4 through 8.1 of this standard.

There are two means by which an *intentional island* system can transition to an islanded condition: scheduled and unscheduled.

[111] Reliance solely on under/over voltage and frequency trip is not considered sufficient to detect and *cease to energize* and trip. IEEE Std 1547.2™ [B18] may provide additional guidance on *unintentional island* mitigation, and additional equipment (e.g., transfer trip) may be necessary.
[112] To achieve coordination between unintentional islanding detection and automatic reclosing, auto-reclose times longer than 2 s may be considered in some circumstances.
[113] It is important to bear in mind that islanding detection methods in inverters are generally designed to detect islands with a generation-load balance. They are *not* intended or designed to detect faults and should not be relied upon for that purpose.
[114] Also called “Facility Island,” see Annex C.

8.2.2 Scheduled intentional islands

Scheduled *intentional islands* are formed through DER operator or Area EPS operator manual action or other operating dispatch means (e.g., Energy Management System or Automatic Generator Control action) that trigger the transition from being in parallel and synchronized with the Area EPS, to operation as an islanded system. Reasons for forming a scheduled *intentional island* can include enhanced reliability, economic dispatch decisions for self-supply or import/export of power with or through the Area EPS, or pre-emptive Area EPS operator action to island ahead of inclement weather.

8.2.3 Unscheduled intentional islands

Unscheduled *intentional islands* are formed autonomously from local detection of abnormal conditions at the interconnection(s) with the Area EPS, and then automatic relay action that triggers switching action to isolate the *intentional island* rapidly from the Area EPS.

8.2.4 Conditions for unscheduled transition to intentional island

An *intentional island* may disconnect from the Area EPS and transition to *intentional island* mode for any of the following conditions:

- Whenever any of the exception conditions described in 6.4.2.1 and 6.5.2.1 are met, or
- If any of the trip conditions described in Clause 6 are met (i.e., where Clause 6 would allow or mandate tripping, the *intentional island* may transition to *intentional island* mode), or
- If the conditions of 8.1 are met (i.e., the DER detects an island and the DER ceases to energize the Area EPS under 8.1), the *intentional island* may enter *intentional island* mode instead of ceasing to energize the Area EPS, provided that the *intentional island* does not energize any part of the Area EPS that is outside the defined *intentional island*).

8.2.5 Transition of an intentional island from the Area EPS

If an *intentional island* that does not qualify as an exception under 6.4.2.1 or 6.5.2.1 disconnects from the Area EPS when the voltage and frequency of the Area EPS are within the *Continuous Operation* ranges defined in Clause 6, the conditions of 7.2.2, as applicable, shall be met.

8.2.6 Reconnection of an intentional island to the Area EPS

An *intentional island* that has disconnected from the rest of the Area EPS may reconnect to the rest of the Area EPS when the conditions listed in 4.10 are met at the *intentional island* point of common coupling. When the *intentional island* reconnects to the Area EPS, the conditions of 4.10.4 shall be met.

8.2.7 Adjustments to DER settings

When operating in an *intentional Area EPS island*, participating DER may have to adjust several control and protection settings. These alternate settings and *ranges of allowable settings*, including those specified in 8.2.7, shall be enabled only when the *intentional Area EPS island* is isolated from the Area EPS. In order to meet this requirement, adaptive protection and control settings may be required.

For DER operating in an *intentional Area EPS island*, the following requirements apply:

- 5.2 (reactive power capability of the DER) and 5.3 (voltage and reactive power control) for all aggregate DER ratings.

— 6.4.1 (mandatory voltage tripping) the *range of allowable settings* in overvoltage trip function 2 (OV2) shall be 0.008 s to 0.16 s for all three categories, in Table 11, Table 12, and Table 13.

— 6.5.1 (mandatory frequency tripping) the *range of allowable settings* in overfrequency trip setting 1 (OF1) and underfrequency trip setting 1 (UF1) shall be 11 s to 1000 s for all three categories, in Table 18.

— 6.5.2.7 (frequency-droop) for all aggregate DER ratings. For DER complying with Category III of Table 23, the frequency droop (k_{OF}) shall be adjustable from 0.0055 to 0.05 per-unit. For participating DER in Category III of Table 24, the lower value of the range of allowable settings of the open-loop response time is not applicable.

— Shall be capable of operating in Area EPS-connected mode, in *intentional island* mode, and transitioning between those two states.

8.2.8 DER categories for intentional islands

A DER that participates in an *intentional Area EPS island* shall be categorized in one of the following ways:

1) Uncategorized: A DER not designed for *intentional island* operation may be allowed to participate in the *intentional island* if certain system criteria are met (for examples of this, please see Annex C). Otherwise, it shall *cease to energize* the Area EPS during *intentional island* mode, as if it were an *unintentional island*.
2) *Intentional island*-capable: Applies to DER that can disable or modify its islanding detection function, and adjust settings as described in 8.2.7.
3) Black start-capable: Applies to *intentional island*-capable DER that can also energize an EPS that contains no other energy sources.
4) Isochronous-capable: Applies to DER that can independently regulate voltage and frequency to fixed set points.

These categories shall be stated by the DER operator, but utilization shall be by mutual agreement between the DER operator and the operator of the *intentional Area EPS island*. In no case shall a DER be required to operate outside of the voltage, current, and frequency ratings required to provide capabilities and performance as mandated by this standard.

9. DER on distribution secondary grid/area/street (grid) networks and spot networks

9.1 Network protectors and automatic transfer scheme requirements

Network protectors (NPs) shall not be used to connect, separate, switch, serve as breaker failure backup, or in any manner isolate a network or network primary feeder to which DER is connected from the remainder of the network, unless the protectors are rated and tested per applicable standards for such an application.[115]

Unless specified otherwise by the Area EPS operator, DER installations on a network, using an automatic transfer scheme in which load is transferred between the DER and the EPS in a momentary make-before-break operation, shall meet all the requirements of this clause regardless of the duration of paralleling.

[115] IEEE Std C57.12.44™ [B25] provides guidance on the capabilities of network systems to accept distributed resources.

Power flow during this transition shall be positive from the Area EPS to the load and the DER unless approved by and coordinated with the Area EPS operator.

DER on grid or spot networks shall have provisions to

- Monitor instantaneous power flow at the PCC of the DER interconnected to the secondary grid or spot network for reverse power relaying, minimum import relaying, dynamically controlled inverter functions and similar applications to prevent reverse power flow through network protectors.
- Maintain a minimum import level at the PCC as determined by the Area EPS operator.
- Control DER operation or disconnect the DER from the Area EPS based on an autonomous setting at the PCC and/or a signal sent by the Area EPS operator.

DER on grid or spot networks shall not

- Cause any NP to exceed its loading or fault-interrupting capability.
- Cause any NP to separate dynamic sources.
- Cause any NP to connect two dynamic systems together.
- Cause any NP to operate more frequently than prior to DER operation.
- Prevent or delay the NP from opening for faults on the Area EPS.
- Delay or prevent NP closure.
- Energize any portion of an Area EPS when the Area EPS is de-energized.
- Require the NP settings to be adjusted except by consent of the Area EPS operator.
- Prevent reclosing of any network protectors installed on the network. This coordination shall be accomplished without requiring any changes to prevailing network protector *clearing time* practices of the Area EPS.

9.2 Distribution secondary grid networks

In addition to the requirements in 9.1, DER on secondary grid networks shall not cause an islanding condition within that network.

In addition to the requirements in 9.1, in the event of an adjacent feeder fault, network protector master relays shall not be actuated by the presence of DER. The interconnected DER shall be coordinated with NP relay functions and shall be evaluated by the Area EPS operator to ensure network reliability.

9.3 Distribution secondary spot networks

In addition to the requirements in 9.1, connection of the DER to the Area EPS is only permitted if the Area EPS network bus is already energized by more than 50% of the installed network protectors.[116]

[116] See IEEE Std 1547.6 [B21] for more explanation for this requirement.

10. Interoperability, information exchange, information models, and protocols[117]

10.1 Interoperability requirements

A DER shall have provisions for a local DER interface capable of communicating (*local DER communication interface*) to support the information exchange requirements specified in this standard for all applicable functions that are supported in the DER.

Under mutual agreement between the Area EPS operator and DER operator additional communication capabilities are allowed.

The decision to use the *local DER communication interface* or to deploy a communication system shall be determined by the Area EPS operator.

Emergency and standby DER are exempt as specified in 4.13 from the interoperability requirements specified in this standard.

10.2 Monitoring, control, and information exchange requirements

The specific DER functionality required by this standard results in the set of mandatory information elements identified in 10.3 through 10.6. These information elements shall be supported by the DER as indicated to support the associated DER functionality.

For information interoperability, these communication capabilities shall use a unified information model, and non-proprietary protocol encodings based on international standards or open industry specifications as described in 10.7.

The information to be exchanged falls into the following four categories:

— Nameplate information: This information is indicative of the as-built characteristics of the DER. This information may be read.

— Configuration information: This information is indicative of the present capacity and ability of the DER to perform functions. This information may be read or written.

— Monitoring information: This information is indicative of the present operating conditions of the DER. This information may be read.

— Management information: This information is used to update functional and mode settings for the DER. This information may be read or written.

10.3 Nameplate information

Nameplate information shall be available through a *local DER communication interface* and include at a minimum the information contained in Table 28.

[117] This standard mandates these interoperability capabilities; however, how they are implemented, recorded, and reported is up to local jurisdictions and should be addressed in those processes and procedures (such as interconnection agreements).

Table 28 —Nameplate information

Parameter	Description
Active power rating at unity power factor (nameplate active power rating)	Active power rating in watts at unity power factor
Active power rating at specified over-excited power factor	Active power rating in watts at specified over-excited power factor
Specified over-excited power factor	Over-excited power factor as described in 5.2
Active power rating at specified under-excited power factor	Active power rating in watts at specified under-excited power factor
Specified under-excited power factor	Under-excited power factor as described in 5.2
Apparent power maximum rating	Maximum apparent power rating in voltamperes
Normal operating performance category	Indication of reactive power and voltage/power control capability. (Category A/B as described in 1.4)
Abnormal operating performance category	Indication of voltage and frequency ride-through capability Category I, II, or III, as described in 1.4
Reactive power injected maximum rating	Maximum injected reactive power rating in vars
Reactive power absorbed maximum rating	Maximum absorbed reactive power rating in vars
Active power charge maximum rating	Maximum active power charge rating in watts
Apparent power charge maximum rating	Maximum apparent power charge rating in voltamperes. May differ from the apparent power maximum rating
AC voltage nominal rating	Nominal AC voltage rating in RMS volts
AC voltage maximum rating	Maximum AC voltage rating in RMS volts
AC voltage minimum rating	Minimum AC voltage rating in RMS volts
Supported control mode functions	Indication of support for each control mode function
Reactive susceptance that remains connected to the Area EPS in the *cease to energize* and trip state	Reactive susceptance that remains connected to the Area EPS in the *cease to energize* and trip state
Manufacturer	Manufacturer
Model	Model
Serial number	Serial number
Version	Version

10.4 Configuration information

Configuration information shall be available through a *local DER communication interface* to allow the setting and reading of the currently active values.

Each rating in Table 28 may have an associated configuration setting that represents the as-configured value. If a configuration setting value is different from the corresponding nameplate value, the configuration setting value shall be used as the rating within the DER. Changes to the configuration setting shall be made with mutual agreement between the DER system operator and Area EPS operator.

Configuration settings are intended to be used as a configuration option as nameplate alternatives. Configuration settings are not intended for continuous dynamic adjustment.

10.5 Monitoring information

The DER shall be capable of providing monitoring information through a *local DER communication interface* at the reference point of applicability and shall include at a minimum the information contained in Table 29. The information shall be the latest value that has been measured within the required response time.

Table 29—Monitoring information

Parameter	Description
Active Power	Active power in watts
Reactive Power	Reactive power in vars
Voltage	Voltage(s) in volts. (One parameter for single-phase systems and three parameters for three-phase systems)
Frequency	Frequency in Hertz
Operational State	Operational state of the DER. The operational state should represent the current state of the DER. The minimum supported states are on and off but additional states may also be supported
Connection Status	Power-connected status of the DER
Alarm Status	Active alarm status
Operational State of Charge	0% to 100% of operational energy storage capacity

10.6 Management information

10.6.1 General

Management information is used to update functional and mode settings for the DER. This information may be read or written.

10.6.2 Constant power factor mode parameters

Parameters for constant power factor mode as described in 5.3.2 shall be available for reading and writing through a *local DER communication interface*. Power factor value and excitation encoding are protocol-dependent. See Table 30.

Table 30—Constant power factor mode parameters

Parameter	Description	Range
Constant Power Factor Mode Enable	Enable constant power factor mode	On/Off
Constant Power Factor	Constant power factor setting	0−1
Constant Power Factor Excitation	Constant power factor excitation setting	Over-excited or under-excited

NOTE—The terms “over-excited” and “under-excited” are illustrated in the informative Figure H.3 in Annex H.

10.6.3 Voltage-reactive power mode parameters

Parameters for voltage-reactive power mode as described in 5.3.3 shall be available for reading and writing through a *local DER communication interface*. See Table 31.

Table 31 —Voltage-reactive power mode parameters

Parameter	Description	Range
Voltage-Reactive Power Mode Enable	Enable voltage-reactive power mode	On/Off
V_{Ref}	Reference voltage	0.95–1.05 p.u. *V* nominal
Autonomous V_{Ref} adjustment enable	Enable/disable autonomous V_{Ref} adjustment	On/Off
V_{Ref} adjustment time constant	Adjustment range for V_{Ref} time constant	300 s to 5000 s
V/Q Curve Points	Voltage-reactive power curve points	See Table 8
Open Loop Response Time	Time to ramp up to 90% of the new reactive power target in response to the change in voltage	1 s to 90 s

10.6.4 Active power-reactive power mode parameters

Parameters for active power-reactive power mode as described in 5.3.4 shall be available for reading and writing through a *local DER communication interface*. See Table 32.

Table 32 —Active power-reactive power mode parameters

Parameter	Description	Range
Active Power-Reactive Power Mode Enable	Enable active power-reactive power mode	On/Off
P/Q Curve Points	Active power-reactive power curve points	See Table 9

10.6.5 Constant reactive power mode parameters

Parameters for constant reactive power mode as described in 5.3.5 shall be available for reading and writing through a *local DER communication interface*. See Table 33.

Table 33 —Constant reactive power mode parameters

Parameter	Description	Range
Constant Reactive Power Mode Enable	Enable constant reactive power mode.	On/Off
Constant Reactive Power	Constant reactive power setting.	Refer to Table 7 for reactive power settings for Category A and B DER

10.6.6 Voltage-active power mode parameters

Parameters for voltage-active power mode as described in 5.4.2 shall be available for reading and writing through a *local DER communication interface*. See Table 34.

Table 34 —Voltage-active power mode parameters

Parameter	Description	Range
Voltage-Active Power Mode Enable	Enable voltage-active power mode.	On/Off
V/P Curve Points	Voltage-active power curve points.	See Table 10
Open Loop Response Time	Time to ramp up to 90% of the new active power target in response to the change in voltage.	0.5–60 s

10.6.7 Voltage trip and momentary cessation parameters

Parameters for voltage trip as described in 6.4.1 shall be available and the *momentary cessation* threshold as specified in 6.4.2.1 may be available for information exchange through a *local DER communication interface*. Both settings, if applicable, shall be specified as a set of piecewise linear curves that define the regions associated with the voltage regions described in the functional description. See Table 35 (mandatory) and Table 36 (not mandatory).

Table 35—Voltage trip parameters

Parameter	Description	Range
HV Trip Curve Points	High-voltage shall trip curve points.	See Table 11 through Table 13
LV Trip Curve Points	Low-voltage shall trip curve points.	See Table 11 through Table 13

Table 36—Momentary cessation parameters (not mandatory)

Parameter	Description	Range
HV Momentary Cessation Curve Points	High-voltage momentary cessation curve points. Support for this setting is not mandatory.	Refer to 6.4.2.7.3
LV Momentary Cessation Curve Points	Low-voltage momentary cessation curve points. Support for this setting is not mandatory.	Refer to 6.4.2.7.3

10.6.8 Frequency trip parameters

Parameters for frequency trip as described in 6.5.1 shall be available for reading and writing through a *local DER communication interface*. Frequency trip settings shall be specified as a set of piecewise linear curves that define the regions associated with the frequency regions described in the functional description. See Table 37.

Table 37—Frequency parameters

Parameter	Description	Range
HF Trip Curve Points	High frequency shall trip curve points	See Table 18
LF Trip Curve Points	Low frequency shall trip curve points	See Table 18

10.6.9 Frequency droop parameters

Parameters for frequency droop as described in 6.5.2.7 shall be available for reading and writing through a *local DER communication interface*. See Table 38.

Table 38 —Frequency droop parameters

Parameter	Description	Range
Overfrequency Droop db_{OF}	Frequency droop deadband for overfrequency conditions	See Table 24
Underfrequency Droop db_{UF}	Frequency droop deadband for underfrequency conditions	See Table 24
Overfrequency Droop k_{OF}	Frequency droop per-unit frequency change for overfrequency conditions corresponding to 1 per-unit power output change	See Table 24
Underfrequency Droop k_{UF}	Frequency droop per-unit frequency change for underfrequency conditions corresponding to 1 per-unit power output change	See Table 24
Open Loop Response Time	The duration from a step change in control signal input until the output changes by 90% of its final change, before any overshoot	See Table 24

10.6.10 Enter service

Parameters for *enter service* as described in 4.10 shall be available for reading and writing through a *local DER communication interface*. See Table 39.

Table 39 —Enter service after trip parameters

Parameter	Description	Range
Permit service	Able to enter or stay in service	Enabled/Disabled
ES Voltage High	Enter service voltage high	See Table 4
ES Voltage Low	Enter service voltage low	See Table 4
ES Frequency High	Enter service frequency high	See Table 4
ES Frequency Low	Enter service frequency low	See Table 4
ES Delay	Enter service delay	0–600 s
ES Randomized Delay	Enter service randomized delay	1–1000 s
ES Ramp Rate	Enter service ramp rate	1–1000 s

10.6.11 Cease to energize and trip

A DER can be directed to *cease to energize* and trip by changing the Permit service setting to “disabled” as described in 4.10.3.

10.6.12 Limit maximum active power

Parameters to limit maximum active power as specified in 4.6.2 shall be available for reading and writing through a *local DER communication interface*. See Table 40.

Table 40 —Limit maximum active power parameters

Parameter	Description	Range
Limit Active Power Enable	Enable mode	On/Off
Maximum Active Power	Maximum active power setting	Refer to 4.6.2

10.7 Communication protocol requirements

The protocol requirements set forth in this subclause apply at the *local DER communication interface*. As illustrated in Figure 4, the protocols and physical layers utilized within communication networks and within the DER may differ according to the network architecture and technology, and are out of scope of this standard.[118]

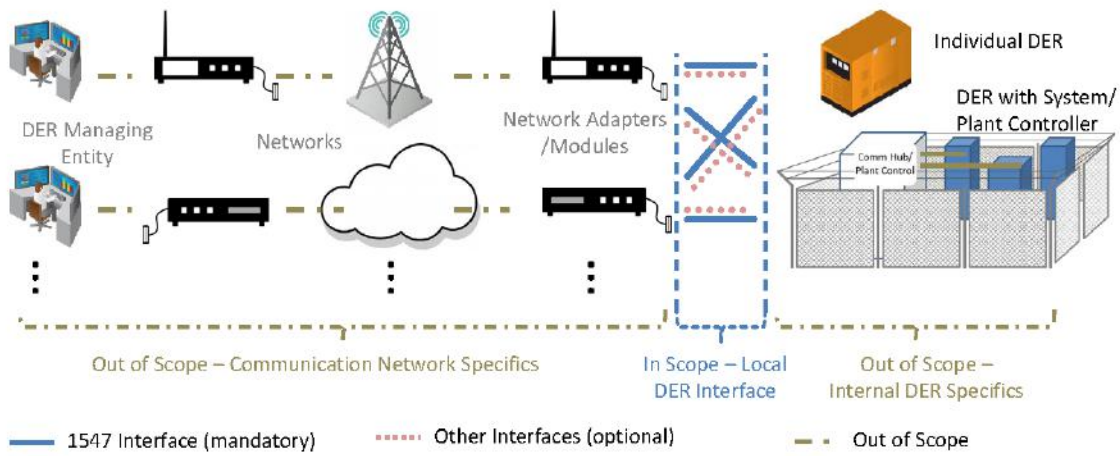


Figure 4 —Control protocol in/out of scope mapping

The DER shall support at least one of the protocols specified in Table 41. The protocol to be utilized may be specified by the Area EPS operator. Additional protocols, including proprietary protocols, may be allowed under mutual agreement between Area EPS operator and DER operator. Additional physical layers may be supported along with those specified in the table.

Table 41 —List of eligible protocols

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

10.8 Communication performance requirements

Communication performance requirements for the interface to DER are set forth in Table 42. These requirements do not constrain or define the performance of various communication systems that may be utilized to integrate DER, but only apply to the DER themselves.

[118] For example, the Area EPS operator may deploy networks that utilize the IEEE 2030.5 protocol even if it is not the native protocol supported at the *local DER communication interface*. The standard protocol support requirement does not preclude the use of additional protocols such as the information model defined by IEC 61850-7-420 [B8] exchanged using IEC 61850-8-1 [B9] or IEC 61850-8-2 [B10], or profiles of the IEC 61850-7-420 information model mapped to IEEE Std 1815 (DNP3) or to SunSpec Modbus.

Table 42—Communication performance requirements for DER interfaces

Parameter	Requirement	Description
Availability of communication	When DER is operational	The *local DER communication interface* shall be active and responsive whenever the DER is operating and in a *continuous operation region* or *mandatory operation region*.
Information read response time	≤ 30 s	The maximum amount of time to respond to read requests.

10.9 Cyber security requirements

It is recognized that cybersecurity is a critically important issue for DER deployments connected to broader monitoring and control communications networks. Each standardized *local DER communication interface* option provides different security capabilities. The interoperability and communications cyber security requirements of specific DER deployments may be based on mutual agreement and may also be subject to regulatory requirements that may vary across jurisdictions.

This standard, therefore, does not mandate specific cyber security requirements at the DER interface. Specific security requirements are beyond the scope of this standard.

See D.4 for more information about cyber security standards.

11. Test and verification requirements

11.1 Introduction

The technical requirements specified in Clause 4 through Clause 10 define the interconnection and interoperability requirements of this standard. These requirements are tested and verified in accordance with the requirements identified in Clause 11.

The requirements contained in this standard identify the necessary conditions that shall be verified to improve proper and reliable operation of the DER. These requirements include properties of the DER, properties that shall be maintained at operational interfaces, and properties that are needed throughout the life of the installed system. All DER verification requirements contained in this document shall be met, and then verified in accordance with IEEE Std 1547.1 [B17]. Depending upon the circumstances and selected verification method, it is possible that additional requirements may be imposed to establish confidence in means of verification, e.g., traceability to national standards, accuracy of recorded data, conditions of unit under test, temporary patches and turnarounds.

This clause specifies the applicable testing and verification methods to verify that a DER meets the interconnection and interoperability requirements specified in Clause 4 through Clause 10 at the applicable reference point as specified in 4.2. This clause further specifies at which stage in the interconnection process testing and verification shall be required. The applicable test and verification methods from this clause are required for all DERs.[119] The results of these test and verification methods shall be formally documented.[120]

[119] The stated test specifications and requirements are universally needed for interconnection of DER including synchronous machines, induction machines, or static power inverters/converters, and are sufficient for most installations.
[120] The responsibilities, procedures, requirements, and criteria for the applicable test and verification methods are specified in IEEE Std 1547.1 [B17].

11.2 Definition of test and verification methods

11.2.1 General

All DER interconnection and interoperability requirements of this standard shall be demonstrated through either type tests, production tests, DER evaluation, commissioning tests, or periodic tests or a combination of these tests and verification methods. Requirements and capabilities that are only partially[121] verified through type testing shall be fully verified through DER evaluation and commissioning tests.

11.2.2 Type tests

A type test may be performed on one device or combination of devices. In case of a combination of devices forming a system, this test shows that the devices are able to operate together as a system.

Type tests shall be performed, as applicable, to the specific DER unit or DER system. The tests shall be performed on a representative DER unit or DER system, either in the factory, at a testing laboratory, or on equipment in the field. Type test results from a DER within a product family of the same design, including hardware and software, shall be allowed as representative of other DERs within the same product family with power ratings between 50% to 200% of the tested DER.

For systems in the field, replacement of DER equipment with substitutive components compliant and tested with this standard shall be allowed and not invalidate previous type test and production test results. However, field demonstration of performance shall be as agreed with the EPS operator and DER operator.

11.2.3 Production tests

Production tests shall be conducted on every unit of DER and interconnect of equipment prior to customer delivery as to verify that they meet applicable standards.

Production tests shall verify the operability of every unit of DER and interconnect equipment manufactured for customer use. These tests assume that the equipment has met the applicable interconnection and interoperability requirements of this standard and may be conducted as a factory test or performed as part of a DER evaluation or commissioning test. The summary reporting shall provide a list of normal and abnormal performance category capability, final function settings, and final operating mode settings.

Manufacturers having certified production facilities or proven production processes and quality control methods certified by a NRTL shall be allowed to use said approved practices and documentation for fulfilment of production test requirements.

For systems in the field, replacement of DER equipment with substitutive components compliant and tested with this standard shall be allowed and not invalidate previous production test results. However, field demonstration of performance shall be as agreed with the Area EPS operator and DER operator.

[121] Partial verification may occur for DER that may have to meet requirements at the PCC per Clause 4 or that require a supplemental DER device to meet requirements at the PoC.

11.2.4 DER evaluation

11.2.4.1 General

DER evaluation comprises a design evaluation desk study during the interconnection review process and an as-built installation evaluation on site at the time of commissioning to verify that the composite of the individual partially compliant DER(s) and, if applicable, the supplemental DER device(s) forming a system meet the interconnection and interoperability requirements of this standard.

11.2.4.2 DER design evaluation (desk study)

The design evaluation (desk study) is an evaluation during the interconnection review process to verify that the composite of the individual partially compliant DERs forming a system as designed meets the interconnection and interoperability requirements of this standard. This evaluation is usually done off-site before equipment is delivered and installed.

11.2.4.3 DER as-built installation evaluation (on-site)

The as-built installation evaluation (on-site) is an evaluation at the time of commissioning to verify that the composite of the individual partially compliant DERs forming a system as delivered and installed meets the interconnection and interoperability requirements of this standard. This evaluation does not require testing.

11.2.4.4 Basic and detailed DER evaluation

A basic DER evaluation shall be limited to verify that the DER has been designed and installed with the proper components and connections. A detailed DER evaluation shall include an engineering verification of the chosen components and may require modeling and simulation of the composite of the individual partially compliant DERs forming a system.

11.2.5 Commissioning tests and verifications

11.2.5.1 General

Commissioning tests are tests and verifications on one device or combination of devices forming a system to confirm that the system as designed, delivered, and installed meets the interconnection and interoperability requirements of this standard.

All commissioning tests shall be performed based on written test procedures. Test procedures are provided by equipment manufacturers(s) or system designer(s) and approved by the equipment owner and Area EPS operator. Commissioning tests shall include visual inspections and may include, as applicable, operability and functional performance test.

11.2.5.2 Basic and detailed functional commissioning test

A basic functional commissioning test includes visual inspection and an operability test on the isolation device. A detailed functional commissioning test shall include a basic functional test and functional tests to verify interoperability of a combination of devices forming a system to verify that the devices are able to operate together as a system.

11.2.6 Periodic tests and verifications

Periodic tests are tests and verifications, according to a scheduled time period or other criteria, that confirm that one already interconnected device or combination of devices forming a system meets the interconnection and interoperability requirements of this standard.

Periodic test requirements and intervals for all interconnection-related protective functions and associated batteries shall be provided by interconnection equipment manufacturers or system integrator and approved by, the AGIR or the Area EPS operator. Frequency of retesting shall be determined by Area EPS operator policies for protection system testing, or manufacturer requirements. Periodic test reports or a log for inspection shall be maintained.

The Area EPS operator may require a commissioning test be performed outside of the normal periodic testing to verify adherence to this standard at any time.

For systems in the field, replacement of DER equipment with substitutive components compliant to this standard shall be allowed and not invalidate previous type test and production test results. The Area EPS operator may still require commissioning testing on any equipment replaced.

Information describing facility changes such as; (software, firmware, hardware) shall be available to the Area EPS operator through the interoperability requirements of Clause 10. Reverification of the interconnection and interoperability requirements of this standard may be required when any of the following events occur:

- Functional software or firmware changes have been made on the DER.
- Any hardware component of the DER has been modified in the field or has been replaced or repaired with parts that are not substitutive components compliant with this standard.
- Protection settings have been changed after factory testing.
- Protection functions have been adjusted after the initial commissioning process.

11.3 Full and partial conformance testing and verification

11.3.1 General

Requirements define the capability, design, and performance of a built system. Test and verification is confirming that the requirements have been satisfactorily met. The test and verification requirements are specified by use of a test requirements matrix as described in Table 43 and Table 44. These matrices provide a means of traceability between the need to verify a given requirement and the means of verification. These matrices help ensure that there is consistency throughout the stages in interconnection process testing and verification for DER that shall meet requirements in Clause 4 through Clause 10. Test requirement matrices provide minimum testing requirements for traceability, but the Area EPS operator shall not be limited from requiring supplemental commissioning testing and verification.

Note that this document presents two traceability matrices—one for connections at the PCC and one for requirements to be tested at the PoC. As indicated in 4.2, many applications exist where the applicable point for meeting performance requirements shall be the PoC. This includes small-scale DER, applications where DER units are interconnected to Local EPS having substantial load.

According to 4.2, the requirements of this standard apply either at the PCC or the PoC, depending on the aggregate nameplate DER rating and the average annual load in the Local EPS.[122] Where requirements apply at the PoC, equipment type testing will be sufficient to verify conformance with most requirements, in most cases. However, for DER facilities, i.e., Local EPS that are large enough so that requirements apply at the PCC, equipment testing will have to be supplemented by additional compliance verification measures such as the DER evaluation and further commissioning tests defined above. The same holds for any DER that use supplemental DER devices to meet the requirements of this standard. Annex F provides further information concerning testing and verification requirements at the PCC or PoC, including the concept of combined type test and DER evaluation.

NOTE—Subclause 11.3 only maps the required test and verification procedures to the performance requirements of this standard. The subclause does not specify exactly how these procedures are implemented. The details of the actual test and verification procedures are specified in IEEE Std 1547.1 [B17].

11.3.2 DER that shall meet requirements at the PCC

This subclause outlines a methodology for testing and verification of DER that may be used to demonstrate conformance at the PCC per Clause 4 through Clause 10 for interconnection and interoperability requirements of this standard. The Area EPS operator may have additional requirements for the interconnection.

For DER that shall meet requirements at the PCC per 4.2, Table 43 specifies the test and verification requirements.[123]

The DER system or DER unit[124] shall be classified as either fully compliant or partially compliant. Type tests, DER evaluations, and commissioning tests shall be done as indicated in the table for all line items under the appropriate classification.

[122] As per 4.2 some DER units have some requirements that shall be met at the PCC and other requirements that shall be met at the PoC.
[123] The corresponding responsibilities, procedures, requirements, and criteria for the applicable test and verification methods are specified in IEEE Std 1547.1 [B17].
[124] Individual DER units that are considered fully compliant at the PoC may only be considered fully compliant at the PCC if the impedance between the PoC and the PCC is less than 0.5% on the DER rated apparent power and voltage base.

Table 43—Interconnection test specifications and requirements for DER that shall meet requirements at the PCC

LEGEND	
DER system	DER system is fully compliant at PCC*—no supplemental DER device needed *Individual DER units that are considered fully compliant at the PoC may only be considered fully compliant at the PCC if the impedance between the PoC and the PCC is less than 0.5% on the DER rated apparent power and voltage base.
Composite	Composite of partially compliant DER that is, as a whole, fully compliant at PCC*—may need one or more supplemental DER device(s). *Individual DER units that are considered fully compliant at the PoC shall not be considered fully compliant at the PCC if the impedance between the PoC and the PCC is equal to or greater than 0.5% on the DER rated apparent power and voltage base.
NR	Not Required
R	Required
L	Limited type testing is limited to partial compliance of the individual DER unit or DER system in order to evaluate the DER unit or DER system performance characteristics for later use in the DER evaluation that verifies full compliance of the composite DER at the PCC. The DER unit or DER system may not have any compliance at all with certain requirements, leaning on the supplemental equipment to comply.
D	Dependent on DER Design Evaluation
NA	Not Applicable

Requirement	Compliance at PCC achieved by:	Type tests	DER evaluation	Commissioning tests
4 General interconnection technical specifications and performance requirements				
4.2 Reference points of applicability	DER System	NR	R	NR
	Composite	NR	R	NR
4.3 Applicable voltages	DER System	NR	R	NR
	Composite	NR	R	NR
4.4 Measurement accuracy	DER System	R	R	NR
	Composite	L	R	NR
4.5 Cease to energize performance requirement	DER System	R	R	D
	Composite	L	R	D
4.6 Control capability requirements				
4.6.1 Capability to disable permit service	DER System	R	R	D
	Composite	L	R	D
4.6.2 Capability to limit active power	DER System	R	R	D
	Composite	L	R	D
4.6.3 Execution of mode or parameter changes	DER System	R	R	D
	Composite	L	R	D
4.7 Prioritization of DER responses	DER System	R	R	D
	Composite	L	R	D
4.8 Isolation device	DER System	R	Design: NR Installation: R	NR
	Composite	L	Design: NR Installation: R	D

Requirement	Compliance at PCC achieved by:	Type tests	DER evaluation	Commissioning tests
4.9 Inadvertent energization of the Area EPS	DER System	R	Design: NR Installation: R	D
	Composite	L	R	D
4.10 Enter service (This is a top-level heading and requirements are specified in the subclauses below.)				
4.10.2 Enter service criteria	DER System	R	NR	NR
	Composite	L	R	D
4.10.3 Performance during entering service	DER System	R	R	D
	Composite	L	R	D
4.10.4 Synchronization	DER System	R	R	D
	Composite	L	R	D
4.11 Interconnect integrity (This is a top-level heading and requirements are specified in the subclauses below.)				
4.11.1 Protection from electromagnetic interference	DER System	R	NR	NR
	Composite	L	NR	NR
4.11.2 Surge withstand performance	DER System	R	NR	NR
	Composite	L	NR	NR
4.11.3 Paralleling device	DER System	R	NR	NR
	Composite	L	NR	NR
4.12 Integration with Area EPS grounding	DER System	NR	R	NR
	Composite	NR	R	NR
5 Reactive power capability and voltage/power control requirements				
5.2 Reactive power capability of the DER	DER System	R	R	D
	Composite	L	R	D
5.3 Voltage and reactive power control	DER System	R	Design: NR Installation: R	NR
	Composite	L	R	D
5.3.2 Constant power factor mode	DER System	R	Design: NR Installation: R	NR
	Composite	L	R	D
5.3.3 Voltage-reactive power mode	DER System	R	Design: NR Installation: R	NR
	Composite	L	R	D
5.3.4 Active power-reactive power mode	DER System	R	Design: NR Installation: R	NR
	Composite	L	R	D
5.3.5 Constant reactive power mode	DER System	R	Design: NR Installation: R	NR
	Composite	L	R	D

Requirement	Compliance at PCC achieved by:	Type tests	DER evaluation	Commissioning tests
5.4 Voltage and active power control (This is a top-level heading and requirements are specified in the subclauses below.)				
5.4.2 Voltage-active power mode	DER System	R	Design: NR Installation: R	NR
	Composite	L	R	R
6 Response to Area EPS abnormal conditions				
6.2 Area EPS faults and open phase conditions	DER System	R	Design: R Installation: NR	D
	Composite	L	R	D
6.3 Area EPS reclosing coordination	DER System	NR	Design: R Installation: NR	NR
	Composite	NR	Design: R Installation: NR	R
6.4 Voltage				
6.4.1 Mandatory voltage tripping requirements	DER System	R	Design: R[a] Installation: R[b]	D
	Composite	L	Design: R[a] Installation: R[b]	D
6.4.2.1 General requirements and exceptions	DER System	R	R	D
	Composite	L	R	D[a]
6.4.2.2 Voltage disturbances within continuous operation region	DER System	R	Design: R[a] Installation: R[b]	D
	Composite	L	R	D[a]
6.4.2.3 Low-voltage ride-through (This is a top-level heading and requirements are specified in the subclauses below.)				
6.4.2.3.2 Low-voltage ride-through capability	DER System	R	R	NR
	Composite	L	R	D[a]
6.4.2.3.3 Low-voltage ride-through performance	DER System	R	R	NR
	Composite	L	R	D[a]
6.4.2.4 High-voltage ride-through (This is a top-level heading and requirements are specified in the subclauses below.)				
6.4.2.4.2 High-voltage ride-through capability	DER System	R	NR	NR
	Composite	L	R	D[a]
6.4.2.4.3 High-voltage ride-through performance	DER System	R	NR	NR
	Composite	L	R	D[a]
6.4.2.5 Ride-through of consecutive voltage disturbances	DER System	R	NR	NR
	Composite	L	R	D[a]
6.4.2.6 Dynamic voltage support (This is a top-level heading and requirements are specified in the subclauses below.)				
6.4.2.6.1 Dynamic voltage	DER System	R	R	NR

Requirement	Compliance at PCC achieved by:	Type tests	DER evaluation	Commissioning tests
support capability	Composite	L	R	D
6.4.2.6.2 Dynamic voltage support performance	DER System	R	R	NR
	Composite	L	R	D
6.4.2.7 Restore output with voltage ride-through (This is a top-level heading and requirements are specified in the subclauses below.)				
6.4.2.7.1 Restore output without dynamic voltage support	DER System	R	R	NR
	Composite	L	R	D
6.4.2.7.2 Restore output with dynamic voltage support	DER System	R	R	NR
	Composite	L	R	D
6.4.2.7.3 Transition between performance operating regions for Category III DER	DER System	R	R	NR
	Composite	L	R	D
6.5 Frequency				
6.5.1 Mandatory frequency tripping requirements	DER System	R	Design: R[a] Installation: R[b]	D
	Composite	L	Design: R[a] Installation: R[b]	D
6.5.2.1 General requirements and exceptions	DER System	R	NR	NR
	Composite	L	R	R
6.5.2.2 Frequency disturbances within continuous operation region	DER System	R	NR	NR
	Composite	L	R	R
6.5.2.3 Low-frequency ride-through (This is a top-level heading and requirements are specified in the subclauses below.)				
6.5.2.3.1 Low-frequency ride-through capability	DER System	R	NR	NR
	Composite	NR	NR	NR
6.5.2.3.2 Low-frequency ride-through performance	DER System	R	NR	NR
	Composite	L	R	R
6.5.2.4 High-frequency ride-through (This is a top-level heading and requirements are specified in the subclauses below.)				
6.5.2.4.1 High-frequency ride-through capability	DER System	R	NR	NR
	Composite	L	R	R
6.5.2.4.2 High-frequency ride-through performance	DER System	R	NR	NR
	Composite	L	R	R
6.5.2.5 Rate of change of frequency (ROCOF) ride-through	DER System	R	NR	NR
	Composite	L	R	R
6.5.2.6 Voltage phase angle changes ride-through	DER System	R	NR	NR
	Composite	L	Design: R Installation: NR	D

Requirement	Compliance at PCC achieved by:	Type tests	DER evaluation	Commissioning tests
6.5.2.7 Frequency-droop (frequency-power) (This is a top-level heading and requirements are specified in the subclauses below.)				
6.5.2.7.1 Frequency-droop (frequency-power) capability	DER System	R	NR	NR
	Composite	L	R	D
6.5.2.7.2 Frequency-droop (frequency-power) operation	DER System	R	NR	NR
	Composite	L	R	D
6.6 Return to service after trip	DER System	R	NR	NR
	Composite	L	R	D
7 Power quality				
7.1 Limitation of dc injection	DER System	R	NR	NR
	Composite	NR	R	NR
7.2 Limitation of voltage fluctuations induced by the DER (This is a top-level heading and requirements are specified in the subclauses below.)				
7.2.2 Rapid voltage changes (RVC)	DER System	NR	Design: R Installation: NR	D
	Composite	NR	Design: R Installation: NR	D
7.2.3 Flicker	DER System	NR	Design: R Installation: NR	D
	Composite	NR	Design: R Installation: NR	D
7.3 Limitation of current distortion	DER System	R	NR	NR
	Composite	L	R	D
7.4 Limitation of overvoltage contribution	DER System	R	R	D
	Composite	L	R	D
8 Islanding				
8.1 Unintentional islanding	DER System	R	NR	NR
	Composite	L	R[c]	R[d]
8.1.2 Conditional extended clearing time	DER System	R	R	NR
	Composite	L	R	R[d]
8.1.3Area EPS with automatic reclosing	DER System	R	R	NR
	Composite	L	R	R[d]
8.2 Intentional islanding (This is a top-level heading and requirements are specified in the subclauses below.)				
8.2.2 Scheduled intentional islands	DER System	NA	NA	NA
	Composite	L	R	R
8.2.3 Unscheduled intentional islands	DER System	NA	NA	NA
	Composite	L	R	R
8.2.4 Conditions for unscheduled	DER System	NA	NA	NA

Requirement	Compliance at PCC achieved by:	Type tests	DER evaluation	Commissioning tests
transition to intentional island	Composite	L	R	R
8.2.5 Transition of an intentional island from the Area EPS	DER System	NA	NA	NA
	Composite	L	R	R
8.2.6 Reconnection of an intentional island to the Area EPS	DER System	NA	NA	NA
	Composite	L	R	R
8.2.7 Adjustments to DER settings	DER System	NA	NA	NA
	Composite	L	R	R
8.2.8 DER categories for intentional islands	DER System	NA	NA	NA
	Composite	L	R	R
9 DER on distribution secondary grid/area/street (grid) networks and spot networks				
9.2 Distribution secondary grid networks	DER System	NR	R	D
	Composite	NR	R	D
9.3 Distribution secondary spot networks	DER System	NR	R	D
	Composite	NR	R	D
10 Interoperability, information exchange, information models, and protocols				
10.1 Interoperability requirements	DER System	R	R	NR
	Composite	L	R	D
10.2 Monitoring, control, and information exchange requirements	DER System	R	R	NR
	Composite	L	R	D
10.3 Nameplate	DER System	R	NR	NR
	Composite	L	R	D
10.4 Configuration information	DER System	R	NR	NR
	Composite	L	R	D
10.5 Monitoring information	DER System	R	NR	NR
	Composite	L	R	D
10.6 Management information (This is a top-level heading and requirements are specified in the subclauses below.)				
10.6.2 Constant power factor mode parameters	DER System	R	NR	NR
	Composite	L	R	D
10.6.3 Voltage-reactive power mode parameters	DER System	R	NR	NR
	Composite	L	R	D
10.6.4 Active power-reactive power mode parameters	DER System	R	NR	NR
	Composite	L	R	D
10.6.5 Constant reactive power mode parameters	DER System	R	NR	NR
	Composite	L	R	D
10.6.6 Voltage-active power mode parameters	DER System	R	NR	NR
	Composite	L	R	D

Requirement	Compliance at PCC achieved by:	Type tests	DER evaluation	Commissioning tests
10.6.7 Voltage trip and momentary cessation parameters	DER System	R	NR	NR
	Composite	L	R	D
10.6.8 Frequency trip parameters	DER System	R	NR	NR
	Composite	L	R	D
10.6.9 Frequency droop parameters	DER System	R	NR	NR
	Composite	L	R	D
10.6.10 Enter service	DER System	R	NR	NR
	Composite	L	R	D
10.6.11 Cease to energize and trip	DER System	R	NR	NR
	Composite	L	R	D
10.6.12 Limit maximum active power	DER System	R	NR	NR
	Composite	L	R	D
10.7 Communication protocol requirements	DER System	R	NR	NR
	Composite	L	R	D
10.8 Communication performance requirements	DER System	R	NR	NR
	Composite	L	R	D

[a]Align trip settings at DER devices and substation.
[b]Verify correct installation settings.
[c]Islanding trip time test data can be used to assist in the DER design evaluation line item for 6.3.
[d]Some supplemental equipment may require commissioning.

A system design verification shall be made to help ensure that the requirements of 6.2 (for Area EPS faults) have been met. Type tests shall be made to verify the requirements of 6.2 (for individual open phase conditions) of this standard have been met. The Type test (set-up) and certification record shall include each of the specific interconnection transformer vector groups with which the specific DER unit is intended to be interconnected. DER evaluations and/or commissioning tests may also be made to verify the requirements of 6.2 for the DER (for individual open phase conditions) of this standard have been met.

11.3.3 DER that shall meet requirements at the PoC

The test and verification requirements are specified by use of a test requirements matrix (Table 44). This matrix provides a means of traceability between the need to verify a given requirement and the means of verification. These matrices ensure that there is consistency throughout the stages in interconnection process testing and verification for DER that shall meet requirements at the PoC.

This subclause outlines a methodology for testing and verification of DER that may be used to demonstrate conformance at the PoC per Clause 4 through Clause 10 for interconnection and interoperability requirements of this standard. The Area EPS operator may have additional requirements for interconnection.

For DER that shall meet requirements at the PoC per 4.2, Table 44 specifies the test and verification requirements.[125]

The DER unit shall be classified as either fully compliant or partially compliant. Type tests, DER evaluations, and commissioning tests shall be done as indicated in the table for all line items under the appropriate classification.

Table 44—Interconnection test specifications and requirements for DER that shall meet requirements at the PoC

LEGEND	
DER Unit	Individual DER unit is fully compliant at the PoC—no supplemental DER device needed
Composite	Composite of partially-compliant individual DER units that is, as a whole, fully compliant at PoC may need one or more supplemental DER device(s)
NR	Not Required
R	Required
L	Limited type testing is limited to partial compliance of the individual DER unit in order to evaluate the DER unit performance characteristics for later use in the DER evaluation that verifies full compliance of the composite DER at the PoC. The DER unit may not have any compliance at all with certain requirements, leaning on the supplemental equipment to comply.
D	Dependent on DER Design Evaluation
NA	Not Applicable

Requirement	Compliance at PoC achieved by:	Type tests	DER evaluation	Commissioning tests
4 General interconnection technical specifications and performance requirements				
4.2 Reference points of applicability	DER Unit	NR	R	NR
	Composite	NR	R	NR
4.3 Applicable voltages	DER Unit	NR	R	NR
	Composite	NR	R	NR
4.4 Measurement accuracy	DER Unit	R	NR	NR
	Composite	L	R	NR
4.5 Cease to energize performance requirement	DER Unit	R	NR	NR
	Composite	L	R	D
4.6 Control capability requirements				
4.6.1 Capability to disable permit service	DER Unit	R	NR	NR
	Composite	L	R	D
4.6.2 Capability to limit active power	DER Unit	R	NR	NR
	Composite	L	R	D
4.6.3 Execution of mode or parameter changes	DER Unit	R	NR	NR
	Composite	L	R	D
4.7 Prioritization of DER responses	DER Unit	R	NR	NR
	Composite	L	R	D

[125] The corresponding responsibilities, procedures, requirements, and criteria for the applicable test and verification methods are specified in IEEE Std 1547.1 [B17].

Requirement	Compliance at PoC achieved by:	Type tests	DER evaluation	Commissioning tests
4.8 Isolation device	DER Unit	R	NR	NR
	Composite	L	Design: NR Installation: R	D
4.9 Inadvertent energization of the Area EPS	DER Unit	R	Design: NR Installation: R	D
	Composite	L	R	R
4.10 Enter service (This is a top-level heading and requirements are specified in the subclauses below.)				
4.10.2 Enter service criteria	DER Unit	R	NR	NR
	Composite	L	R	D
4.10.3 Performance during entering service	DER Unit	R	R	D
	Composite	L	R	D
4.10.4 Synchronization	DER Unit	R	R	D
	Composite	L	R	D
4.11 Interconnect integrity (This is a top-level heading and requirements are specified in the subclauses below.)				
4.11.1 Protection from electromagnetic interference	DER Unit	R	NR	NR
	Composite	L	NR	NR
4.11.2 Surge withstand performance	DER Unit	R	NR	NR
	Composite	L	NR	NR
4.11.3 Paralleling device	DER Unit	R	NR	NR
	Composite	L	NR	NR
4.12 Integration with Area EPS grounding	DER Unit	NR	R	NR
	Composite	NR	R	NR
5 Reactive power capability and voltage/power control requirements				
5.2 Reactive power capability of the DER	DER Unit	R	NR	NR
	Composite	L	R	NR
5.3 Voltage and reactive power control (This is a top-level heading and requirements are specified in the subclauses below.)				
5.3.2 Constant power factor mode	DER Unit	R	NR	NR
	Composite	L	R	R
5.3.3 Voltage-reactive power mode	DER Unit	R	NR	NR
	Composite	L	R	R
5.3.4 Active power-reactive power mode	DER Unit	R	NR	NR
	Composite	L	R	R
5.3.5 Constant reactive power mode	DER Unit	R	NR	NR
	Composite	L	R	R
5.4 Voltage and active power control (This is a top-level heading and requirements are specified in the subclauses below.)				
5.4.2 Voltage-active power mode	DER Unit	R	R	NR
	Composite	L	R	R
6 Response to Area EPS abnormal conditions				

Requirement	Compliance at PoC achieved by:	Type tests	DER evaluation	Commissioning tests
6.2 Area EPS faults and open phase conditions	DER Unit	R	Design: R Installation: NR	NR
	Composite	L	R	NR
6.3 Area EPS reclosing coordination	DER Unit	NR	Design: R[a] Installation: NR	NR
	Composite	NR	Design: R Installation: NR	D
6.4 Voltage				
6.4.1 Mandatory voltage tripping requirements	DER Unit	R	Design: R[b] Installation: R[c]	NR
	Composite	L	Design: R[b] Installation: R[c]	NR
6.4.2.1 General requirements and exceptions	DER Unit	R	NR	NR
	Composite	L	R	D
6.4.2.2 Voltage disturbances within continuous operation region	DER Unit	R	NR	NR
	Composite	L	Design: R Installation: NR	D
6.4.2.3 Low-voltage ride-through (This is a top-level heading and requirements are specified in the subclauses below.)				
6.4.2.3.2 Low-voltage ride-through capability	DER Unit	R	NR	NR
	Composite	L	Design: R Installation: NR	D
6.4.2.3.3 Low-voltage ride-through performance	DER Unit	R	Design: R Installation: NR	D
	Composite	L	Design: R Installation: NR	D
6.4.2.4 High-voltage ride-through (This is a top-level heading and requirements are specified in the subclauses below.)				
6.4.2.4.2 High-voltage ride-through capability	DER Unit	R	NR	NR
	Composite	L	Design: R Installation: NR	D
6.4.2.4.3 High-voltage ride-through performance	DER Unit	R	NR	NR
	Composite	L	Design: R Installation: NR	D
6.4.2.5 Ride-through of consecutive voltage disturbances	DER Unit	R	NR	NR
	Composite	L	Design: R Installation: NR	D
6.4.2.6 Dynamic voltage support (This is a top-level heading and requirements are specified in the subclauses below.)				
6.4.2.6.1 Dynamic voltage support capability	DER Unit	R	NR	NR
	Composite	L	R	D
6.4.2.6.2 Dynamic voltage support performance	DER Unit	R	NR	NR
	Composite	L	R	D

Requirement	Compliance at PoC achieved by:	Type tests	DER evaluation	Commissioning tests
6.4.2.7 Restore output with voltage ride-through (This is a top-level heading and requirements are specified in the subclauses below.)				
6.4.2.7.1 Restore output without dynamic voltage support	DER Unit	R	NR	NR
	Composite	L	R	D
6.4.2.7.2 Restore output with dynamic voltage support	DER Unit	R	NR	NR
	Composite	L	R	D
6.4.2.7.3 Transition between performance operating regions for Category III DER	DER Unit	R	NR	NR
	Composite	L	R	D
6.5 Frequency				
6.5.1 Mandatory frequency tripping requirements	DER Unit	R	Design: R[b] Installation: R[c]	D
	Composite	L	Design: R[b] Installation: R[c]	D
6.5.2.2 Frequency disturbances within continuous operation region	DER Unit	R	NR	NR
	Composite	L	NR	NR
6.5.2.3 Low-frequency ride-through (This is a top-level heading and requirements are specified in the subclauses below.)				
6.5.2.3.1 Low-frequency ride-through capability	DER Unit	R	NR	NR
	Composite	L	NR	NR
6.5.2.3.2 Low-frequency ride-through performance	DER Unit	R	NR	NR
	Composite	L	NR	NR
6.5.2.4 High-frequency ride-through (This is a top-level heading and requirements are specified in the subclauses below.)				
6.5.2.4.1 High-frequency ride-through capability	DER Unit	R	NR	NR
	Composite	L	NR	NR
6.5.2.4.2 High-frequency ride-through performance	DER Unit	R	NR	NR
	Composite	L	NR	NR
6.5.2.5 Rate of change of frequency (ROCOF) ride-through	DER Unit	R	NR	NR
	Composite	L	NR	NR
6.5.2.6 Voltage phase angle changes ride-through	DER Unit	R	NR	NR
	Composite	L	NR	NR
6.5.2.7 Frequency-droop (frequency-power) (This is a top-level heading and requirements are specified in the subclauses below.)				
6.5.2.7.1 Frequency-droop (frequency-power) capability	DER Unit	R	NR	NR
	Composite	L	R	D
6.5.2.7.2 Frequency-droop (frequency-power) operation	DER Unit	R	NR	NR
	Composite	L	R	D
6.6 Return to service after trip	DER Unit	R	NR	NR
	Composite	L	R	D
7 Power quality				
7.1 Limitation of dc injection	DER Unit	R	NR	NR
	Composite	L	R	NR

Requirement	Compliance at PoC achieved by:	Type tests	DER evaluation	Commissioning tests
7.2 Limitation of voltage fluctuations induced by the DER (This is a top-level heading and requirements are specified in the subclauses below.)				
7.2.2 Rapid voltage changes (RVC)	DER Unit	NR	Design: R Installation: NR	D
	Composite	NR	Design: R Installation: NR	D
7.2.3 Flicker	DER Unit	NR	Design: R Installation: NR	D
	Composite	NR	Design: R Installation: NR	D
7.3 Limitation of current distortion	DER Unit	R	NR	NR
	Composite	L	R	D
7.4 Limitation of overvoltage contribution	DER Unit	R	R	D
	Composite	L	R	D
8 Islanding				
8.1 Unintentional islanding	DER Unit	R	NR	NR
	Composite	L	R[d]	R[e]
8.1.2 Conditional extended clearing time	DER Unit	R	NR	NR
	Composite	L	R	R[e]
8.1.3Area EPS with automatic reclosing	DER Unit	R	NR	NR
	Composite	L	R	R[c]
8.2 Intentional islanding (This is a top-level heading and requirements are specified in the subclauses below.)				
8.2.2 Scheduled intentional islands	DER Unit	NR	NR	NR
	Composite	L	R	R
8.2.3 Unscheduled intentional islands	DER Unit	NR	NR	NR
	Composite	L	R	R
8.2.4 Conditions for unscheduled transition to intentional island	DER Unit	NR	NR	NR
	Composite	L	R	R
8.2.5 Transition of an intentional island from the Area EPS	DER Unit	NR	NR	NR
	Composite	L	R	R
8.2.6 Reconnection of an intentional island to the Area EPS	DER Unit	NR	NR	NR
	Composite	L	R	R
8.2.7 Adjustments to DER settings	DER Unit	NR	NR	NR
	Composite	L	R	R
8.2.8 DER categories for intentional islands	DER Unit	NR	NR	NR
	Composite	L	R	R
9 DER on distribution secondary grid/area/street (grid) networks and spot networks				
9.2 Distribution secondary grid networks	DER Unit	NR	R	D
	Composite	NR	R	D

Requirement	Compliance at PoC achieved by:	Type tests	DER evaluation	Commissioning tests
9.3 Distribution secondary spot networks	DER Unit	NR	R	D
	Composite	NR	R	D
10 Interoperability, information exchange, information models, and protocols				
10.1 Interoperability requirements	DER Unit	R	NR	NR
	Composite	L	R	D
10.2 Monitoring, control, and information exchange requirements	DER Unit	R	NR	NR
	Composite	L	R	D
10.3 Nameplate	DER Unit	R	NR	NR
	Composite	L	R	D
10.4 Configuration information	DER Unit	R	NR	NR
	Composite	L	R	D
10.5 Monitoring information	DER Unit	R	NR	NR
	Composite	L	R	D
10.6 Management information (This is a top-level heading and requirements are specified in the subclauses below.)				
10.6.2 Constant power factor mode parameters	DER Unit	R	NR	NR
	Composite	L	R	D
10.6.3 Voltage-reactive power mode parameters	DER Unit	R	NR	NR
	Composite	L	R	D
10.6.4 Active power-reactive power mode parameters	DER Unit	R	NR	NR
	Composite	L	R	D
10.6.5 Constant reactive power mode parameters	DER Unit	R	NR	NR
	Composite	L	R	D
10.6.6 Voltage-active power mode parameters	DER Unit	R	NR	NR
	Composite	L	R	D
10.6.7 Voltage trip and momentary cessation parameters	DER Unit	R	NR	NR
	Composite	L	R	D
10.6.8 Frequency trip parameters	DER Unit	R	NR	NR
	Composite	L	R	D
10.6.9 Frequency droop parameters	DER Unit	R	NR	NR
	Composite	L	R	D
10.6.10 Enter service	DER Unit	R	NR	NR
	Composite	L	R	D
10.6.11 Cease to energize and trip	DER Unit	R	NR	NR
	Composite	L	Design: NR Installation: R	D
10.6.12 Limit maximum active power	DER Unit	R	NR	NR
	Composite	L	R	D
10.7 Communication protocol requirements	DER Unit	R	NR	NR
	Composite	L	R	D
10.8 Communication performance	DER Unit	R	NR	NR

Requirement	Compliance at PoC achieved by:	Type tests	DER evaluation	Commissioning tests
requirements	Composite	L	R	D

[a]Islanding trip time test data, from the line item for 8.1 in this table, can be used to assist in the DER design evaluation.
[b]Align trip settings at DER devices and substation.
[c]Verify correct installation settings.
[d]Islanding trip time test data can be used to assist in the DER design evaluation line item for 6.3.
[e]Some supplemental equipment may require commissioning.

A system design verification shall be made to ensure that the requirements of 6.2 (for Area EPS faults) of this standard have been met. Type tests shall be made to verify the requirements of 6.2 (for individual open phase conditions) have been met. The Type test (set-up) and certification record shall include each of the specific interconnection transformer vector groups with which the specific DER unit is intended to be interconnected. DER evaluations and/or commissioning tests may also be made to verify the requirements of 6.2 for the DER (for individual open phase conditions) of this standard have been met.

11.4 Fault current characterization

11.4.1 General

This subclause defines tests and documentation of parameters that are useful in characterizing DER current contributions to Area EPS faults.[126]

11.4.2 Electronically coupled DER

This subclause applies to electronically coupled generation with aggregate rated capacity of 500 kVA or greater. This requirement shall also apply to three-phase systems comprised of three sets of single-phase systems, if the aggregate facility rating at the PCC is 500 kVA or greater. The objective is to determine the controller response of the DER under certain fault conditions. The requirements in this subclause exclude directly connected synchronous and induction generators without active control of rotor current.[127]

The DER operator shall provide to the Area EPS operator oscillographic voltage and current data for all three phases measured during type testing. Sequence impedance characteristics of the external source used during DER type tests shall be provided. The DER shall be type tested for maximum short circuit current levels.

11.4.3 Synchronous and induction generator DER

The data requirements for synchronous and induction generator DER are the nameplate kVA rating, synchronous impedance, negative sequence impedance, zero sequence impedance, transient impedance, and subtransient impedances. The requirements in this subclause exclude induction generators with active control of rotor current.

[126] The interconnection of DER may impact the equipment and operation of the EPS. System impact studies identify potential problems and allow the Area EPS operator to determine the modifications to the Area EPS facilities that may mitigate potential problems.
[127] A doubly-fed induction machine is considered to have active control of the rotor current.

Annex A

(informative)

Bibliography

Bibliographical references are resources that provide additional or helpful material but do not need to be understood or used to implement this standard. Reference to these resources is made for informational use only.

[B1] Accredited Standards Committee C2-2012, National Electrical Safety Code® (NESC®).

[B2] BDEW Bundesverband der Energie- und Wasserwirtschaft e.V. (German Association of Energy and Water Industries) (2008): Technical Guideline: Generating Plants Connected to the Medium-Voltage Network. Guideline for generating plants' connection to and parallel operation with the medium-voltage network), revised January 2013.

[B3] Boemer, J. C. (2016): On Stability of Sustainable Power Systems. Network Fault Response of Transmission Systems with Very High Penetration of Distributed Generation. PhD diss. Delft University of Technology, Delft, The Netherlands. Intelligent Electrical Power Grids. Available online at http://doi.org/10.4233/uuid:78bffb19-01ed-48f9-baf6-ffb395be68a0.

[B4] CA Rule 21, California Electric Tariff Rule 21.

[B5] EPRI White Paper, *Recommended Settings for Voltage and Frequency Ride-Through of Distributed Energy Resources.* Product number 3002006203. May 2015. Available online at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002006203.[128]

[B6] FERC Docket RM16-8-000, IEEE P1547 Response to FERC NOPR RM16-8 decision on Proposed Changes Requiring Small Generators to Ride-Through System Disturbances. Submitted by IEEE Standards Association (IEEE SA). May 2016.[129] Available online at https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14461876.

[B7] FERC Order No. 828. Requirements for Frequency and Voltage Ride-Through Capability of Small Generating Facilities. Final Rule. Docket No. RM16-8-000. FERC. July 21, 2016. Available online at http://www.ferc.gov/whats-new/comm-meet/2016/072116/E-11.pdf.

[B8] IEC 61850-7-420, Communication networks and systems for power utility automation—Part 7-420: Basic communication structure—Distributed energy resources logical nodes.[130]

[B9] IEC 61850-8-1, Communication networks and systems for power utility automation—Part 8-1: Specific communication service mapping (SCSM)—Mappings to MMS (ISO 9506-1 and ISO 9506-2) and to ISO/IEC 8802-3.

[B10] IEC 61850-8-2, Communication networks and systems for power utility automation—Part 8-2. Specific communication service mapping (SCSM)—Mapping to Extensible Messaging Presence Protocol (XMPP).

[B11] IEC TR 61850-80-3, Communication networks and systems for power utility automation—Part 80-3: Mapping to web protocols—Requirements and technical choices.

[B12] IEC 62351-12, Power Systems Management and Associated Information Exchange—Data and Communications Security—Part 12.

[B13] IEEE Std 67™, IEEE Guide for Operation and Maintenance of Turbine Generators.[131, 132]

[128] EPRI publications are available from the Electric Power Research Institute (http://www.epri.com).
[129] FERC dockets are available from Federal Energy Regulatory Commission (https://elibrary.ferc.gov/idmws/docket_sheet.asp).
[130] IEC publications are available from the International Electrotechnical Commission (http://www.iec.ch) and the American National Standards Institute (http://www.ansi.org/).

[B14] IEEE Std 929™, IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems.

[B15] IEEE Std 1001™, IEEE Guide for Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems.

[B16] IEEE Std 1453.1™, IEEE Guide--Adoption of IEC/TR 61000-3-7:2008, Electromagnetic compatibility (EMC)—Limits—Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems.

[B17] IEEE Std 1547.1™, IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems.

[B18] IEEE Std 1547.2™, IEEE Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.

[B19] IEEE Std 1547.3™, IEEE Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems.

[B20] IEEE Std 1547.4™, IEEE Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems.

[B21] IEEE Std 1547.6™, IEEE Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks.

[B22] IEEE Std 1547.7™, IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection.

[B23] IEEE Std 2030®, IEEE Guide for Smart Grid Interoperability of Energy Technology and Information Technology Operation with the Electric Power System (EPS), End-Use Applications, and Loads.

[B24] IEEE Std C37.102™, IEEE Guide for AC Generator Protection.

[B25] IEEE Std C57.12.44™, IEEE Standard Requirements for Secondary Network Protectors.

[B26] NERC Distributed Energy Resources Task Force Report, *Distributed Energy Resources: Connection, Modeling, and Reliability Considerations.* North American Electric Reliability Corporation (NERC), February 2017. Available online at http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf.

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[B28] NERC Report, *1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report. Southern California 8/16/2016 Event.* North American Electric Reliability Corporation (NERC), June 2017. Available online at http://www.nerc.com/pa/rrm/ea/Pages/1200-MW-Fault-Induced-Solar-Photovoltaic-Resource-Interruption-Disturbance-Report.aspx.

[B29] NERC Variable Generation Task Force Report, *Performance of Distributed Energy Resources During and After System Disturbance. Voltage and Frequency Ride-Through Requirements.* North American Electric Reliability Corporation (NERC), Dec 2013. Available online at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/IVGTF17_PC_FinalDraft_December_clean.pdf.

[B30] NERC Special Report, *Potential Bulk System Reliability Impacts of Distributed Resources.* North American Electric Reliability Corporation (NERC), August 2011. Available online at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011%20(2).pdf#search=Reliability%20Impacts%20of%20Distributed%20Resources%2E.

[B31] NFPA 70®, The National Electrical Code® (NEC®).

[131] The IEEE standards or products referred to in Annex A are trademarks owned by The Institute of Electrical and Electronics Engineers, Incorporated.
[132] IEEE publications are available from The Institute of Electrical and Electronics Engineers (http://standards.ieee.org/).
[133] NERC publications are available from the North American Reliability Corporation (http://www.nerc.com/).

[B32] NFPA 110, Standard for Emergency and Standby Power Systems.

[B33] NISTIR 7628, Guidelines for Smart Grid Cybersecurity.

Annex B

(informative)

Guidelines for DER performance category assignment

B.1 Introduction

This annex provides guidance to authorities governing interconnection requirements (AGIR) regarding the assignment of performance categories, as defined in this standard, to Distributed Energy Resources (DER) based on attributes such as technology, application purpose, power generation variability, and the specific characteristics of the point of common coupling with the Area EPS.

As proposed in the IEEE P1547 response to FERC NOPR RM16-8 submitted by the IEEE Standards Association in May 2016 [B6], the criteria for assignment of DER performance categories outlined in the informative Annex B may be used as a reference point to partly specify "Good Utility Practice" for specific ride through requirements as required from small generating facilities per FERC Order 828 [B7].

B.2 Background

Rapidly increasing penetration of DER in the electric power system has driven the need for a limited set of specific DER performance characteristics in this standard, particularly with regard to the following:

— Participation of the DER in the voltage and reactive power management of the Area EPS (Clause 5).

— Voltage and frequency disturbance ride-through capabilities necessary to protect *bulk power system* security and Area EPS power quality (Clause 6 and Clause 7).

The inherent abilities of various DER types to achieve these performance attributes differ. In situations where DER penetration is high, basic levels of performance that can be readily achieved by all DER technologies have been deemed insufficient to meet existing bulk system reliability needs, or to address more localized Area EPS power quality issues.[134] On the other hand, universally requiring high levels of performance that are sufficient to meet BPS reliability and power quality needs in all reasonable situations would, in practice, exclude certain types of DER from interconnection, which is not the intent of this standard.

Often, the DER technologies that would tend to be excluded by uniform minimum performance standards provide unique societal benefits that cannot be provided by technologies that are more readily adaptable to minimum universal electrical performance requirements. An example is DER using synchronous generators. Synchronous generators are inherently limited in their ability to remain connected to the Area EPS during low-voltage (typically fault) events of extended duration.[135] While synchronous generators possess this inherent electrical limitation, they provide additional benefits such as increased system inertia, dispatchable spinning reserve in most typical synchronous generator applications, and other non-electrical

[134] This annex intentionally uses qualitative DER penetration levels qualifiers. The impact of DER on frequency and voltage performance of the interconnections and the regional power systems differs significantly and it remains in the responsibility of an AGIR to quantify impactful DER penetration levels.

[135] Synchronous operation depends on a balance of mechanical power from the prime mover and electrical power to the load (or grid). During a low-voltage event, the electrical power delivered to the Area EPS is inherently reduced, creating a power imbalance that accelerates the rotational speed of the generator. If that imbalance is too great, or persists too long, the machine will lose synchronism. This condition, known as "pole slip," can potentially cause catastrophic damage to the equipment.

and societal benefits. There are a number of DER applications having positive environmental, energy efficiency, or public safety benefits where synchronous generators are the only practical choice. Examples include combined heat and power applications, conversion of waste methane gas, and backup power to critical facilities.

B.3 Normal and abnormal performance category standard approach

B.3.1 General

Worldwide, DER interconnection standards have tended to stipulate performance requirements through technology-specific standards. This approach has been intentionally avoided in the development of this standard for the following reasons:

— It is inherently discriminatory to demand a greater level of performance from one type or technology of DER simply because it can provide the capability, at a cost, while relieving other technologies of that burden due to the infeasibility to meet the requirement. As a matter of policy, IEEE standards should remain technology-neutral where possible, and should definitely not be discriminatory in nature.

— It is exceedingly difficult to accurately categorize all DER technologies, particularly as new technologies may evolve. For example, doubly fed generators, commonly used in wind turbines, behave in some situations like rotating generators and in other situations like power-electronic inverters.

— DER performance is sometimes governed by the characteristics of the prime mover or primary energy source as much as the power conversion device (i.e., generator or inverter). The inherent tendency of technology-based DER performance standards, as adopted elsewhere, is to categorize by the power conversion device without regard to the limitations on performance imposed by the prime mover or primary energy source.

Tradeoffs between electrical performance limitations and the wider societal benefits offered by a particular DER technology or application type can be made. However, evaluation of such non-electrical factors is outside the scope of this IEEE standard. Therefore, this standard defines performance and capability categories to which DER equipment and systems can be designed and tested. The discretion of how to apply the categories to specific technologies, application purposes, and Area EPS point of common coupling characteristics is left to the AGIR.

Figure B.1 gives a high-level overview of the performance-based category approach, which is summarized as follows:

— The AGIR, which could be state regulators, *bulk power system* operators, or the Area EPS operator would perform a DER impact assessment based on anticipated DER deployment for the future. This assessment would consider technical conditions such as future DER penetration levels, DER power output variability, distribution system characteristics, e.g., fault-induced delayed voltage recovery (FIDVR) issues, feeder configuration and protection, as well as bulk system characteristics, e.g., power reserves or future system inertia. It could also consider non-technical issues such as DER use cases and the broader impacts of DER on the environment, emissions, and sustainability. This analysis could be a starting point for a stakeholder process, initiated and managed by the AGIR, with the ultimate goal of assigning DER performance categories to specific DER (technology) types and application purposes (use cases).

— The DER vendors, e.g., manufacturers of PV inverter or synchronous generators, would analyze the costs associated with meeting certain performance categories for their products. They would also analyze their market segments, based on the category assignment of AGIRs, and ultimately make decisions on how to design their products.

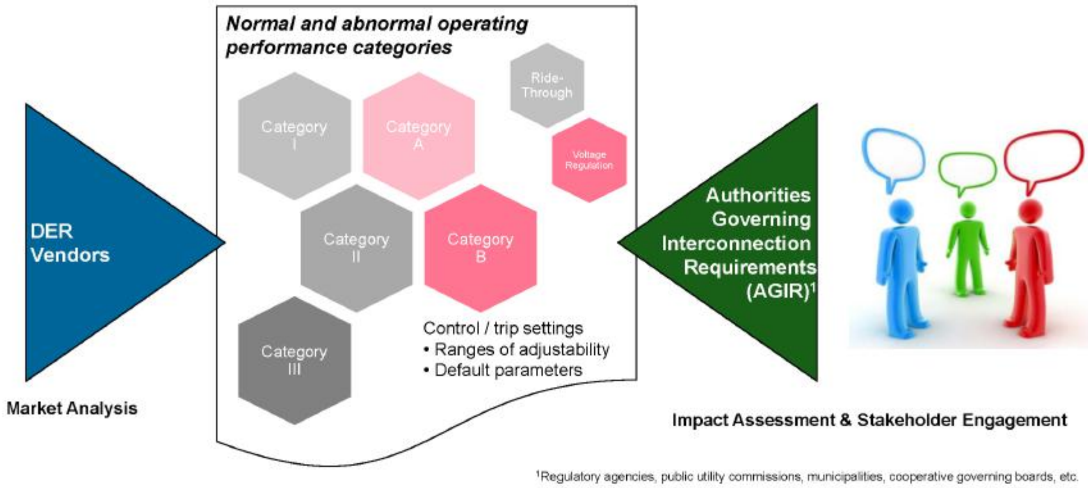


Figure B.1—High-level overview of performance-based category approach

For the application of the standard, the following sets of performance categories are used:

— Categories A and B for voltage regulation performance and reactive power capability requirements (Clause 5)

— Categories I, II, and III for disturbance ride-through requirements (Clause 6)

The performance and capability category levels in Clause 5 and Clause 6 are not inherently tied to each other. Keeping categories for different performance requirements sets de-linked from each other gives the AGIR flexibility to consider the particular characteristics of the DER interconnection.

For example, the AGIR may require less demanding bulk system issues-related requirements (Category I for disturbance ride-through) while still requiring more demanding distribution system issues-related requirements (Category B for voltage regulation) in justified cases. However, for consistency in the levels of performance and capability, it is strongly recommended to pair Category I with Category A, and to pair Category II and Category III with Category B.

The bases and intended purposes for the performance categories defined in this standard are outlined in the following subclauses for information purposes.

B.3.2 Normal performance categories (Clause 5)

B.3.2.1 General

Different characteristics and capabilities for response to voltage variations within the normal operating range are specified in certain parts of Clause 5 for performance Category A, and Category B DER. Under mutual agreement between Area EPS operator and DER operator, requirements other than those specified next are also allowed.

B.3.2.2 Category A

Category A covers minimum performance capabilities needed for Area EPS voltage regulation and are reasonably attainable by all state-of-the-art DER technologies. This level of performance is deemed adequate for applications where the DER penetration in the distribution system is lower, and where the DER power output is not subject to frequent large variations.

B.3.2.3 Category B

Category B covers all requirements within Category A and specifies supplemental capabilities needed to adequately integrate the DER in local Area EPS where the DER penetration is higher or where the DER power output is subject to frequent large variations.

B.3.3 Abnormal performance categories (Clause 6)

B.3.3.1 Category I

Category I is based on minimal *bulk power system* (BPS) reliability needs and is reasonably attainable by all DER technologies that are in common usage today.

The disturbance ride-through requirements for Category I are derived from the German Association of Energy and Water Industries (BDEW [B2]) standard for medium voltage synchronous generators and is one of the most widely applied standards in Europe. Many synchronous generator manufacturers are currently designing products to meet the requirements of this standard.

Category I disturbance ride-through performance, however, is not consistent with the reliability standards imposed on *bulk power system* generation resources. High penetrations of DER having only Category I capabilities could be detrimental to *bulk power system* reliability, but limited penetration of this category would not have a material negative impact. It should be noted that penetration, with regard to *bulk power system* reliability impacts, should be measured on a regional or bulk system-wide[136] basis, and local distribution system penetration levels are not typically of particular relevance.

B.3.3.2 Category II

Category II performance covers all BPS reliability needs and coordinates with the existing BPS reliability standard, NERC PRC-024-2 [B26], developed to avoid adverse tripping of bulk system generators during system disturbances. Additional voltage ride-through capability is specified for DERs, beyond mandatory voltage ride-through defined by NERC PRC-024-2 [B26], to account for the potential for fault-induced delayed voltage recovery on the distribution system, due to distribution load characteristics.

B.3.3.3 Category III

Category III provides the highest disturbance ride-through capabilities, intended to address integration issues such as power quality and system overloads caused by DER tripping in local Area EPS that have very high levels of DER penetration. This category also provides increased *bulk power system* security by further reducing the potential loss of DER during bulk system events. These requirements are based on the California Rule 21 [B4] Smart Inverter requirements.

[136] Synchronous interconnections, such as the Eastern Interconnection, ERCOT, WECC, are examples of bulk systems in this context.

B.4 Performance category assignment

B.4.1 General

Prior to assignment of categories, the needs of the bulk system on a wide basis and regional basis, as well as the local Area EPS, possibly down to feeder level, should be considered.

B.4.2 DER attribute groupings

Before performance level categories can be assigned, a systematic categorization of DER types should be devised. The following list of DER attributes that should be considered is non-exhaustive:

- Power conversion device technology, such as synchronous generator, voltage-source inverter, induction generator, doubly fed generator, etc.
- Primary power source, such as solar, biogas, fossil fuel, hydro, wind, energy storage device, etc.
- Prime mover or type of primary energy source conversion, such as reciprocating engine, turbine, fuel cell, etc.
- DER application purpose, such as combined heat and power (cogeneration), merchant power generation, backup generation for critical facilities, retail customer self-supply, waste fuel recovery, etc.
- Factors related to the point of common coupling into the Area EPS, such as high-penetration feeders, areas of high regional DER penetration, dedicated distribution feeders, relative system strength, PCC location on a specific feeder, etc.
- Inherent output variability of the DER type.
- Other attributes.

The AGIR should identify DER type groupings that consider the previous attributes and any other attributes that may be deemed appropriate. A full matrix of type groupings that considers separately each and every one of the attributes above would be unwieldy and impractical to administer. Therefore, discretion should be applied to combine attributes in a meaningful way to reduce the number of DER types to a manageable level, while also providing adequate means to discriminately apply the performance category assignments in a way that balances total societal benefits and impacts.

B.4.3 Performance category assignment criteria

B.4.3.1 Assignment of normal performance categories (Clause 5)

To deal with power quality issues caused by increasing DER penetration, especially of variable-generation DER, the majority of the DER should have Category B performance. However, DER connected to a PCC that is relatively close to the substation as well as non-variable-generation DER may have less impact on the distribution system voltage than DER that are connected close to the end of a feeder or DER with power output that is subject to frequent large variations. In those cases, it is reasonable to interconnect a limited amount of DER capacity that is limited to Category A voltage regulation performance and reactive power capability.

When making the assignment of performance categories to DER types, it is recommended that the AGIR consider the following questions:

— Is it impractical for the given DER type to be designed to meet Category B?
— Is the power output of the DER constant and not subject to frequent large variations?
— Is the rating of the DER, relative to the distribution system short-circuit strength at the point of common coupling, small such that the DER does not have significant impact on distribution voltage?
— Is the projected penetration of all DER types allowed to interconnect with Category A capability and performance relatively small compared to the total load level on the particular feeder?

Depending on the answers to these questions, the assignment of performance Category A to the particular DER type grouping may be appropriate from the standpoint of power quality issues caused by increasing DER penetration. In certain cases, however, the AGIR might consider imposing higher levels of voltage regulation performance and reactive power capability requirements, but may also consider the overall benefit to impact ratios.

Particularly in areas of high DER penetration and where the predominate DER types involve inherent power output variability (e.g., solar PV), requirements for DER to meet Category B performance may be necessary.

B.4.3.2 Example normal performance category assignment

The categorization of DER types and the assignment of voltage regulation performance and reactive power capability categories based on criteria that are at least partially subjective, is complex. To facilitate this process, an example decision tree for the performance category assignment is provided in Figure B.2. While this figure is an example, it provides a recommended starting point for determining DER attribute groupings and performance category assignments.

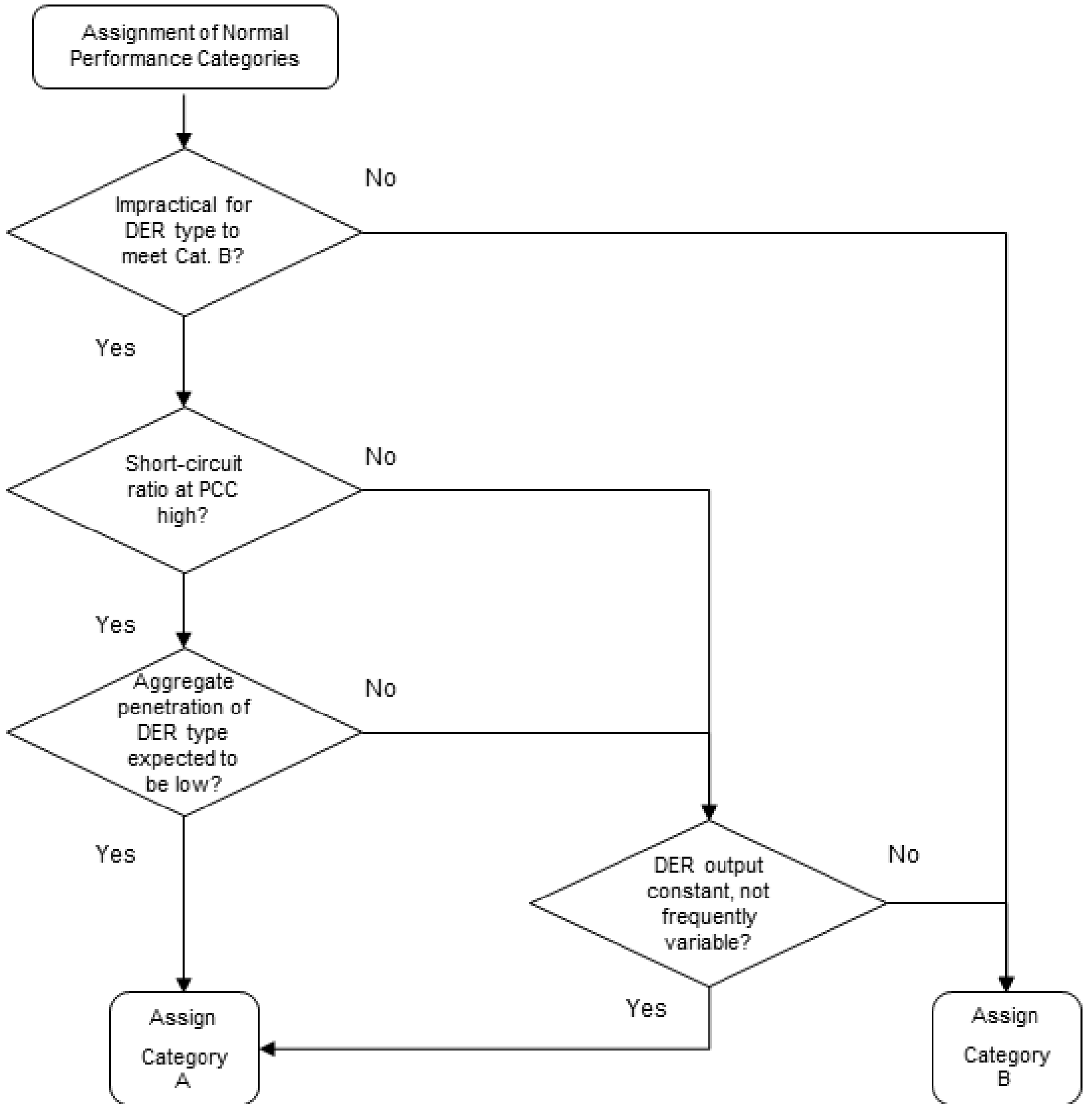


Figure B.2—Example decision tree for normal performance category assignment (Clause 5)

B.4.3.3 Assignment of abnormal performance categories (Clause 6)

To preserve the security of the *bulk power system*, the majority of DER should have Category II disturbance ride-through performance. However, there are notable exceptions when disturbance ride-through performance Category I and III should be applied instead. When the total societal benefits are evaluated, it is reasonable to interconnect a limited amount of DER capacity that is limited to Category I performance and that have other non-electrical benefits.

When making the assignment of performance categories to DER types, it is recommended that the AGIR consider all of the following questions:

— Is it impractical for the given DER type to be designed to meet Category II or III performance?

— Is there a societal benefit provided by the DER type that offsets the potential adverse impact on system security due to reduced capability?

— Is the projected penetration of all DER types allowed to interconnect with Category I performance relatively small compared to the total load level in the region?

NOTE—Bulk electrical system reliability impacts are related to the total amount of DER in a relatively large region, and penetration levels at individual distribution systems or circuits are not of particular relevance.

If the answer to each of the previous is "yes," then assignment of performance Category I to the particular DER type grouping is appropriate from the standpoint of *bulk power system* reliability. In all other cases, the AGIR should assign performance Category II or might consider imposing even higher levels of performance requirements such as Category III, but may also consider the overall benefit to impact ratios.

In areas of particularly high DER penetration and where nuisance tripping of DER could cause voltage collapse or system overloads, requirements for DER to meet Category III performance may be necessary.

Even within such high-penetration regions, it may be reasonable to allow a limited amount of DER with Category I or II performance capabilities that provide unique benefits. An example could be a bio-gas generator that provides consistent power output in a distribution system that also has very high solar PV penetration.

B.4.3.4 Example abnormal performance category assignment

The categorization of DER types and the assignment of disturbance ride-through performance categories based on criteria that are at least partially subjective, is complex. To facilitate this process, an example performance category assignment grid is provided in Table B.1. While this table is an example, it provides a recommended starting point for determining DER attribute groupings and performance category assignments. It is quite possible that an AGIR may also need to define an "all other" application purpose (i.e., column) to accommodate applications not foreseen or otherwise addressed.

Table B.1—Example abnormal performance category assignment grid[137]

DER type		DER application purpose						
		Retail self generation	**Combined heat and power**	**Waste fuel recovery**	**Renewable energy**	**Merchant generation**[a]	**Critical backup**[b]	**Peak shaving**
		A	**B**	**C**	**D**	**E**	**F**	**G**
1	Engine or turbine driven synchronous generator	Category I	Category I	Category I	Category I	Category I	Category I	Category I
2	Wind turbines (all types)	Category II	N/A	N/A	Category II	Category II	N/A	N/A
3	Inverters sourced by solar PV	Category II[c]	N/A	N/A	Category II[c]	Category II[c]	N/A	N/A
4	Inverters sourced by fuel cells	Category I	Category I	Category I	Category I	Category II	Category I	N/A
5	Synchronous hydrogenerators	Category I	N/A	N/A	Category I	Category I	Category I	N/A
6	Other inverter applications	Category II	Category II	Category II	Category II	Category II	Category II	N/A
7	Inverters sourced by energy storage	Category II	N/A	N/A	N/A	Category II	Category II	Category II
8	Other synchronous generators	Category I	Category I	Category I	Category I	Category I	Category I	N/A
9	Other induction generators	Category II	Category II	Category II	Category II	Category II	Category II	Category II

[a]Merchant generation in this table is intended to characterize DER facilities installed for the express purpose of exporting power, and is not intended to imply only FERC-jurisdictional generation or other regulatory definitions.
[b]Only applies to critical backup generation interconnected to the Area EPS for the purposes of periodic testing. If backup generation is also used for merchant generation or other purposes, the performance requirements of those purposes apply.
[c]Category III should be required where DER penetration on a distribution feeder exceeds [% VALUE TO BE SPECIFIED BY AGIR], or on the distribution system supplied from a given distribution substation bus exceeds [% VALUE TO BE SPECIFIED BY AGIR].

[137] The purpose of this table is to provide a recommended starting point for determining DER attribute groupings and performance category assignments. The table is not intended to suggest any equipment capability.

Annex C

(informative)

DER intentional and microgrid island system configurations

C.1 Introduction

Figure C.1, from IEEE Std 1547.4-2011 [B20], shows examples of different kinds of islands incorporating DER. The *intentional island interconnection device* (IIID) is used to create the island, as described in 6.2 of IEEE Std 1547.4-2011 [B20]. For example, CB3 may be opened to create the "Circuit Island" in Figure C.1, and there are five DERs within the "Circuit Island". Those five DERs may have five individual PCCs, or less than five through aggregation. None of the five DER breakers can serve as the IIID in this example. On the other hand, each of those DERs could participate in more than one of the example islands shown. Furthermore, whenever the substation feed is available those DERs can also participate in the non-island mode.

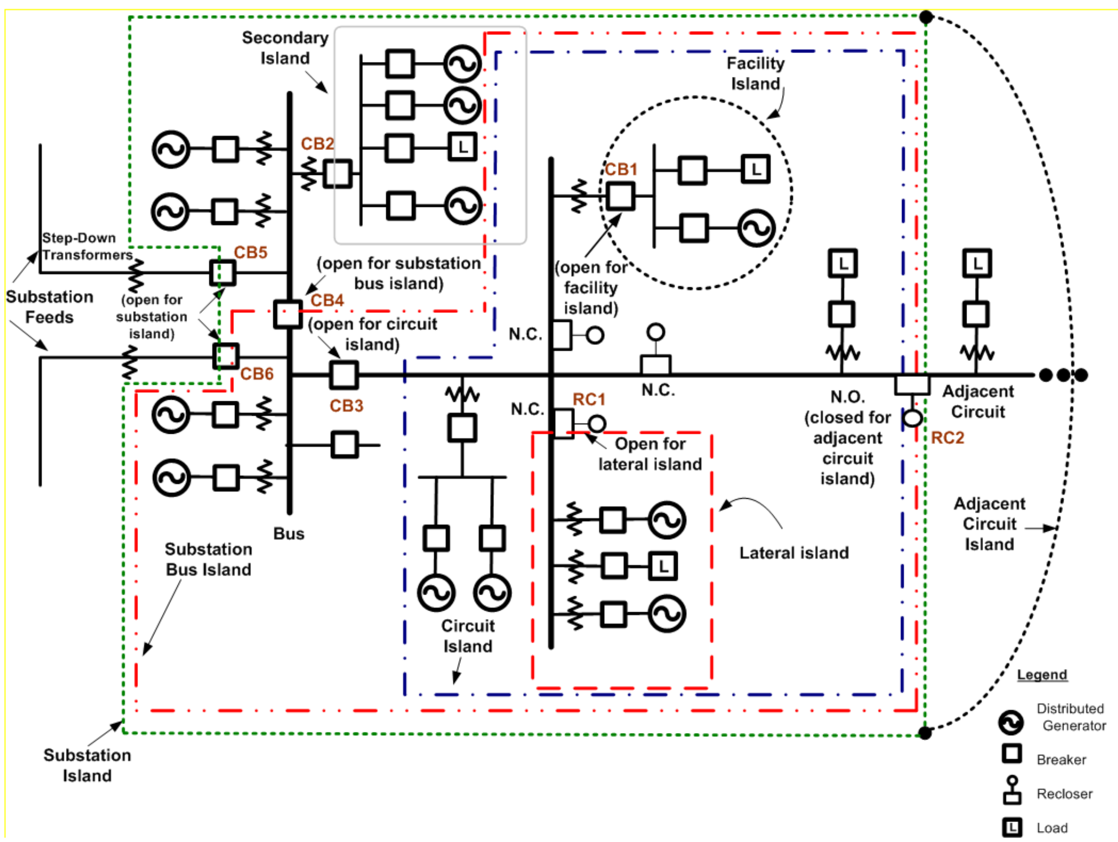


Figure C.1—Examples of DR island systems from IEEE Std 1547.4-2011

This standard is concerned only with the PCC interconnection. The same reasoning applies with example *intentional islands* including microgrids; the *intentional island* or microgrid interface will often not be the same as the PCC interconnection.

Furthermore, this standard is not concerned with *intentional island* or microgrids that operate only as a Local EPS. For example, the "Facility Island" in Figure C.1 is excluded from the scope of this standard, except when CB1 closes for the local DER to participate in the "Circuit Island," the "Substation Bus Island," or the "Substation Island."

C.2 Connecting DER not designed for intentional island or microgrid operation

The following examples outline *intentional island* or microgrid implementations where a DER not designed for *intentional island* or microgrid operation may be allowed to participate by the *intentional island* operator (IIO) or microgrid operator (MO):

— A generator is able to provide the maximum steady-state load in the *intentional island* or microgrid island (MI), and has the speed of response to buffer the power transients of the DER not designed for microgrid operation.

— Energy storage is implemented to buffer the power transients of the DER not designed for *intentional island* or microgrid operation.

— Existing hardware experiments or system operation has proven system stability.

— Simulation studies prove system stability.

— A device has been fitted that disconnects the DER, not designed for *intentional island* or microgrid operation, if outside of an acceptable frequency and voltage window. The system has been proven to be stable, with the disconnection device.

These examples are provided for guidance only; it is the responsibility of the IIO or MO to ensure the desired quality of service in the *intentional island* or microgrid.

Annex D

(informative)

DER communication and information concepts and guidelines

D.1 Introduction

This annex provides additional informative information about the interoperability and communications content in the standard.

D.2 General principles

D.2.1 General

This subclause outlines the general principles used to guide the interoperability and communications content.

D.2.2 Scope

The approach taken for interoperability and communication support in this standard is to specify only the DER functional requirements for communication at the DER interface. It is considered beyond the scope of this standard to specify any requirements related to network technologies that may be used to interface with the *local DER communication interface*.

The interoperability and communication content in this standard is based on the functionality in the standard that specifies settings with a *range of allowable settings*. The purpose of the *local DER communication interface* is to allow all the settings information to be read and written through the interface providing remote adjustability. Monitoring of some measurement and status information is also specified.

D.2.3 Standardized local DER communication interface

A set of protocols have been identified in the normative text that satisfy the requirement for communication support. Each option provides different capabilities inherent in the stack. It is intended that the standardized communication capability of a DER be the basis for a more comprehensive communication solution based on the requirements of a DER installation and other appropriate standards.

It is not mandated that the standardized *local DER communication interface* be used for any DER installation. Proprietary communication interfaces may be developed and used to interface to a DER but the standardized *local DER communication interface* shall always be an available option. The intent is to provide grid stability by offering support for a standardized communication option if a proprietary option is no longer functional for any reason.

Figure D.1 and Figure D.2 show examples of the use of standardized and custom interfaces. In both cases, the IEEE 1547 interface option shall be present. The examples also illustrate the interface that is addressed by this standard and the interfaces that are out of scope.

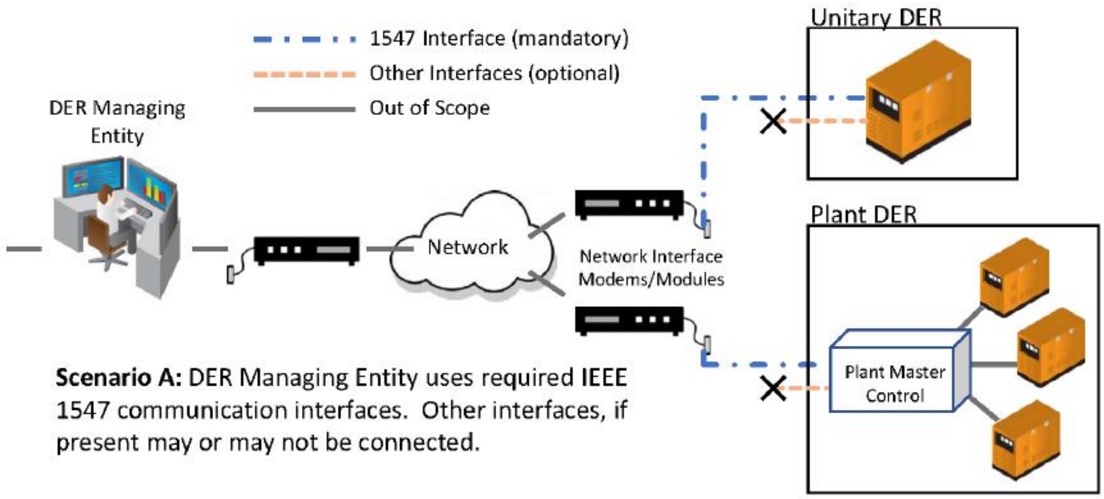


Figure D.1—DER using standardized local DER communication interface

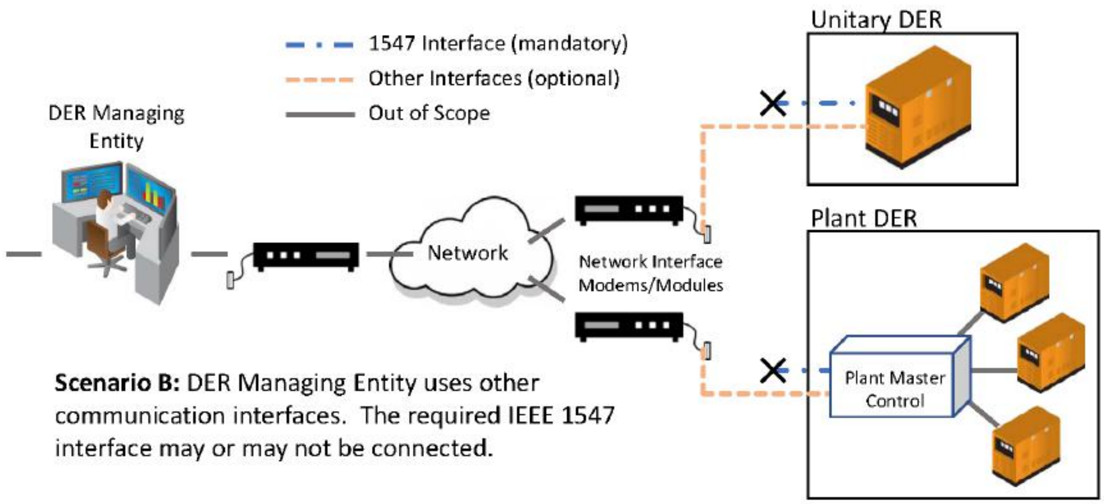


Figure D.2—DER using custom interface

D.2.4 Information model harmonization

In many cases, more than one protocol stack is used to transfer the information between the DER and the managing entity. It is important that information models in each protocol stack be harmonized to maintain the correct meaning of the information being transferred. This harmonization can be facilitated by using industry standard ways of representing certain types of information. The use of piecewise linear curves is an example of information representation that is supported across different protocol information models. This consideration has influenced the choice of information representation in this standard.

D.3 Communication protocols

D.3.1 General

This subclause provides additional detail about the specific protocols that are identified as a standardized interface and other relevant protocols that may be additionally supported.

D.3.2 IEEE Std 2030.5 (SEP2)

IEEE Std 2030.5 provides support for monitoring and control of DER devices. The standard defines the mechanisms for exchanging application messages, the exact messages exchanged including error messages, and the security features used to protect the application messages.

D.3.3 IEEE Std 1815 (DNP3)

IEEE Std 1815 is used to interface to DER devices, often used by utility supervisory control and data acquisition (SCADA) systems. Several specific IEEE 1815 application notes have been developed to support monitoring and control of DER devices.

D.3.4 SunSpec Modbus

The SunSpec Alliance specifies standard Modbus-based information models to support monitoring and control of DER devices.

D.3.5 IEC 61850

IEC 61850-7-420 [B8], specifies the information models to support monitoring and control of DER devices. IEC 61850-7-420 [B8] provides guidelines on the DER functions. IEC 61850-8-2 [B10] defines a standardized protocol based on Internet protocols, and IEC TR 61850-80-3 [B11] provides guidance on the use of web protocols for data exchange.

D.4 Cyber security

D.4.1 DER security requirements

The security requirements associated with DER entail both local physical access and remote network access. The level of security required is proportional to the risk associated with a breach of the system and potential impact on other parts of the system.

The risk profile evaluation associated with different use cases can involve many factors such as the ones listed in the following subclauses.

D.4.2 DER physical security

This standard does not address the requirements associated with physical security of DER systems.

D.4.3 DER front panel security

DER devices often provide front panels to allow interaction by an operator with the DER. This standard does not address the requirements associated with front panel behavior or security.

D.4.4 DER network security

The networks used to connect DER to remote managing entities, and the cyber security requirements of these networks, are out of scope of this standard. DER integration networks will likely be of many kinds and technologies and will use a variety of cyber security mechanisms that evolve over the life of the DER. For this reason, a modular approach has been taken in this standard, excluding the DER network requirements from scope and only specifying the *local DER communication interface*.

D.4.5 Local DER communication interface security

D.4.5.1 General

When a DER is capable of exchanging information through a *local DER communication interface,* consideration should be given to protecting access to DER through that interface. A DER is just like any other system where a malicious or uninformed actor can have an adverse effect on the system.

This standard does not mandate any specific cyber security requirements at the DER interface for at least the following reasons: scope of this standard, scope and complexity of cyber security requirements, system architecture flexibility, and testability.

An additional set of standards may be required to properly address the cyber-physical security requirements of system(s) containing DER and possible requirements specific to the *local DER communication interface*.

D.4.5.2 Scope

Cyber security is a system-wide issue requiring a system-wide solution. This standard specifies the base functionality of a DER including the capability of exchanging specific information over a *local DER communication interface*. This standard cannot correctly address system level issues and should not constrain reasonable system solutions.

D.4.5.3 System architecture

There are many different networking and security scenarios in which a DER may be deployed.

The organization responsible for maintaining the reliability and security of the communications path to the DER must also be able to perform regular maintenance, upgrades, and changes to the network components, including the protocol and cyber security mechanisms.

It is possible to couple a secure networking device with a DER providing an open interface to provide a secure communications path to the DER. Such secure networking devices are common in the utility industry for critical infrastructure integration such as voltage regulators, switches, and capacitors. These networking devices can be designed such that access to the open interface at the DER does not allow access to other devices connected on the same network.

It is important for low-cost DER to be able to be coupled with different networking technologies that may change over the life of the DER. Each networking technology may have different security requirements and solutions.

Non-standardized security features implemented in a DER may make it harder to secure the overall system by requiring workarounds to provide access.

Providing advanced networks for secure DER integration is a science and specialization of its own and DER manufacturers may or may not have this expertise or desire to enter the networking business.

A single network may integrate many different DER types, models, and brands and yet the network provider may need a singular cohesive approach to cyber security system-wide.

DER system software is often a monolithic implementation that does not facilitate tracking and updating based on ongoing changes in the network security arena.

DER manufacturers may stop support for a model or go out of business making it difficult or impossible to fix/update the DER.

D.4.5.4 Testability

Any clause that contains a "shall" declaration shall be able to be tested in IEEE Std 1547.1 [B17]. This is one of the guiding principles for determining what is in scope for the normative content of this standard.

It is difficult to specify meaningful test procedures for general non-standardized requirements.

What types of protections can be provided to assist in preventing unauthorized use of a *local DER communication interface* while providing system design flexibility?

One option is to have the *local DER communication interface* disabled by default and to only enable it through a password-protected front panel interface. This would prohibit access through the *local DER communication interface* until a secure network device is attached. The nature of the physical security and properties of the connection is out of scope for this specification.

D.5 Related standards

D.5.1 IEC 62351-12

IEC 62351-12, Power Systems Management and Associated Information Exchange—Data and Communications Security—Part 12 contains resilience and security recommendations for power systems with distributed energy resources (DER) cyber-physical systems.

D.5.2 IEEE Std 1547.2

IEEE Std 1547.2 [B18] provides technical background and application details to support the understanding of IEEE Std 1547.[138]

[138] At the time of the publication of this standard, IEEE Std 1547.2-2008 is the most recent version of IEEE Std 1547.2 [B18]. This version, however, is inconsistent with the requirements of this version of IEEE Std 1547 and has limited usefulness.

IEEE Std 1547.2 [B18] facilitates the use of IEEE Std 1547 by characterizing the various forms of distributed resource technologies and the associated interconnection issues. Additionally, the background and rationale of the technical requirements are discussed in terms of the operation of the distributed resource interconnection with the electric power system. Presented in the document are technical descriptions and schematics, applications guidance, and interconnection examples to enhance the use of IEEE Std 1547.

D.5.3 IEEE Std 1547.3

IEEE Std 1547.3 [B19] provides guidelines for monitoring, information exchange, and control for distributed resources (DR) interconnected with electric power systems (EPS). The 2007 version requires an update to address current security issues and capabilities that affect high penetrations of DER.

This document facilitates the interoperability of one or more distributed resources interconnected with electric power systems. It describes functionality, parameters, and methodologies for monitoring, information exchange, and control for the interconnected distributed resources with (or associated with) electric power systems. Distributed resources include systems in the areas of fuel cells, photovoltaics, wind turbines, microturbines, other distributed generators, and distributed energy storage systems.

D.5.4 IEEE Std 2030®

IEEE Std 2030 [B23] is an umbrella standard that provides standardized, transparent and systems level guidelines for interoperability between Power, Communications, and Information Systems.

It was the first standard to be created jointly by the three IEEE Societies: Power and Energy Society, Communications Society, and the Computer Society.

It defines the SmartGrid Interoperability Reference Model™ (SGIRM™), which organizes all the functions and interconnections of a Smart Grid in terms of three separate interoperability architecture perspectives (IAPs). The three IAPs primarily relate to logical, functional considerations of power systems, communications interfaces, and IT data flows for smart grid interoperability:

— Power systems IAP (PS-IAP): The emphasis of the power system perspective is the production, delivery, and consumption of electric energy, including apparatus, applications, and operational concepts. This perspective defines seven domains common to all three perspectives: bulk Generation, transmission, distribution, service providers, markets, control/operations, and customers.
— Communications technology IAP (CT-IAP): The emphasis of the communications technology perspective is communication connectivity among systems, devices, and applications in the context of the Smart Grid. The perspective includes communication networks, media, performance, and protocols.
— Information technology IAP (IT-IAP): The emphasis of the information technology perspective is the control of processes and data management flow. The perspective includes technologies that store, process, manage, and control the secure information data flow.

D.5.5 NISTIR 7628

NISTIR 7628 [B33], Guidelines for Smart Grid Cybersecurity, provides additional guidelines for smart grid cyber security that may be applicable to DER deployment. [139]

[139] NIST publications are available from the National Institute of Standards and Technology (https://www.nist.gov/).

Annex E

(informative)

Basis for ride-through of consecutive voltage disturbances

E.1 Introduction

This annex is informative. It is intended to help readers understand the requirements in 6.4.2.5 by use of illustrative figures.

Note that this standard allows an unlimited number of multiple consecutive voltage disturbances that DER are required to ride through within a single disturbance "set," as long as the cumulative duration of all the disturbances in this set does not exceed the maximum required ride-through duration for the respective voltage disturbance severity (and performance category). The standard also requires that DER ride through several of these sets occurring consecutively within a certain time frame. Each voltage disturbance set may correlate to voltage disturbances during a reclosing for a particular sustained fault, intermittent fault activity, or oscillatory voltage triggered by response and recovery of directly-coupled (synchronous or induction) generators to a fault. The several distinct sets may correlate to several unrelated faults occurring within a short time frame or subsequent reclosing event where the reclosing delay is greater than the time separating sets, as would be typical for transmission system faults. The specification for the consecutive voltage disturbance ride-through requirements were derived from typical transmission and primary distribution protection practices and transmission system dynamic behavior.

E.2 Faults, fault protection, and reclosing

The most typical faults on transmission, sub-transmission, and primary distribution power systems are the result of, or result in, "short-circuits" between two or more system phases or between any system phase(s) and a neutral or a grounded part. These short-circuits—unintended, low-impedance, shunt connections—appear in many forms. At the EHV (greater than 300 kV) transmission level comprising the backbone of the *bulk power system*, common causes of faults are insulator contamination, insulator physical failures, switching surges, supporting structure failures, wildfires, and operational errors (e.g., failure to remove personal protective ground jumpers prior to re-energization). Lightning is rarely a cause for EHV line faults, but HV transmission lines do experience lightning-related faults. At the primary distribution and sub-transmission voltage levels the common causes of faults are direct lightning strikes or lightning-induced flashovers, tree branches falling across energized conductors, animals bridging the gap between energized conductors and the grounded parts they are standing on, failures of insulating components or other equipment failures.

Whatever the form of these short-circuits, they have the following two significant effects:

— They cause high-magnitude "fault" current to flow, because the short-circuit bypasses the normal, high-impedance, shunt connections of loads or other equipment connected between the phases, neutral or ground.

— They cause a disturbance in the normal voltage levels, because they change the voltage-divider relationship between the normally low-impedance series paths from sources to loads and the normally high-impedance shunt connections of those loads and other shunt devices.

The high-magnitude currents resulting from a short-circuit fault usually are orders of magnitude above the current-carrying capability of power system equipment, and must be stopped quickly before significant damage is done. Also, the resulting collapse of voltage due to transmission faults eliminates or greatly reduces the ability to transmit power, thus threatening the stability of the *bulk power system*. The use of current differential or impedance detection relaying represents the vast majority of protection employed on transmission systems and in substations against damage from these fault currents. At the EHV transmission level, more sophisticated communication-based protection schemes are used to provide greater detection speed, reliability, selectivity, and security. On primary distribution systems, overcurrent protection is predominantly used. This fault protection is implemented on the transmission lines, substation transformers, and primary distribution circuits between sources and loads, since these are the paths that the high-magnitude current takes directly to a fault if one should occur. These types of protection react to abnormal current or impedance conditions, and the response is usually to cause an opening of the series path to the fault, interrupting the fault current (e.g., through the tripping of a breaker or the operation of a fuse). However, depending on the location of the faulted section, this action can also disconnect the normal flow of power through the power system to the loads beyond the open-circuit that is created.

Utility engineers attempt to apply fault protection devices and relaying to maximize the reliability and speed of detecting and interrupting faults (dependability) while minimizing the number of system elements or customers also interrupted (selectivity) and the chances of an unintended operation (security). This is usually achieved by applying fault protection at as many locations as possible, such as at every transmission line terminal or distribution tap, but applying it in such a way that only the protection for the faulted section operates first. This results in having to coordinate the operation of many protection devices in series along fault current pathways, commonly by selecting zones of protection with deliberately limited overlap, by employing directional discrimination, and by selecting different response time characteristics where protection zones overlap. The response time characteristics determine the speed at which that protection responds to faults in different protection zones or at different levels of current. By applying proper choices of fault protection with coordinated response time characteristics, a reasonable degree of dependability versus security can be achieved between multiple devices along the fault current pathway.

All sources connected on a section of the power system that suffers a fault are expected to *cease to energize* and trip from the rest of the power system by the operation of whatever fault protection is applied. This includes DER on the faulted section, either through their own detection and response to the fault, or through their detection of the resulting unintended island resulting from the operation of the power system fault protection. The DER response is covered in the mandatory tripping requirements of the standard.

While the path of the high-magnitude current caused by a short-circuit fault is restricted to the series paths between the sources and the fault, the voltage disturbances (e.g., voltage dips) caused by a short-circuit fault will be experienced by all devices or equipment connected in close proximity to the fault,[140] even if not on the faulted section. Examples include wide-area voltage disturbances caused by faults on transmission systems, and localized voltage disturbances caused by faults on distribution systems. The extent of the system that can experience these disturbances can range from just the small nearby portion of a single distribution circuit affected by a fault on an adjacent section of the circuit, to an entire interstate region affected by a high-voltage transmission fault. In these cases, if the voltage disturbance is not severe enough or does not last long enough, DER on these portions of the system are required to "ride-through" these disturbances and remain in operation as described in 6.4.2.

An additional aspect of fault protection on utility power systems is that many short-circuit faults are temporary. Most typically, temporary fault is caused by a flashover across an insulator or open-air gap that does no permanent damage, and will cease to exist once the current has been interrupted to clear the resulting arc. Such flashovers are typically caused by transient overvoltages related to lightning strikes or (at the EHV transmission level) switching transients. At the distribution level, temporary faults are also caused by a tree branch or an animal that falls off or is blasted clear after making initial contact with energized conductors. Because temporary faults often make up a sizeable share of the types of faults that occur on power systems, attempts are often made to quickly re-energize the disconnected portion of the power system once the interruption by fault protection has taken place. This practice is known as automatic reclosing. It is commonly performed by reclosing relays controlling circuit breakers or, commonly on

[140] This proximity is in an electrical context relative to the impedance network around the location of the fault, rather than a geographical context.

distribution systems, by reclosers (devices distinct from breakers, but similar in function for this discussion).

Reclosing is the application of a finite number of automatic closures (reclosures) of the breaker or recloser in a brief window of time to re-energize the faulted section of the system. If the fault was temporary and no longer exists upon re-energization, then the fault protection has nothing to respond to and electric service or transmission path is restored with no further action. If the fault is persistent or re-ignites, the fault protection will cause the breaker or recloser to trip again. This tripping and reclosing will happen as many times as the number of selected reclosing attempts applied for that device. If the device continues to trip beyond the number of selected reclosures, it will cease any further attempts and go into a “lockout” state. If the device recloses and does not trip again within a selected “reset” time, it will revert back to its normal pre-fault state and start a brand new reclosing sequence the next time it trips for a fault.

Faults at the transmission level, followed by unsuccessful reclosing attempts, appear as multiple consecutive undervoltage events. (In some situations, the system response to fault clearing may also result in multiple periods of overvoltage as well.) These consecutive voltage disturbances may affect DER over a wide geographic area.

There are two significant consequences to DER from the application of automatic reclosing at the distribution level. First, for situations where the DER trips due to a fault on the section to which they are connected, that tripping shall occur prior to the first reclosing attempt to re-energize the section. Second, for situations where DER rides through a voltage disturbance due to a fault on a different section, the DER shall ride through a series of multiple consecutive voltage disturbances due to the re-appearance of that fault upon each reclosure in the selected reclosing sequence.

The series of multiple consecutive voltage disturbance experienced by the DER, whether from transmission or distribution system faults, can be characterized as repeating periods of abnormal voltages during the times that the fault is present, separated by periods of relatively normal voltages during the times that the fault is disconnected or not active. Examples of what the DER may experience are illustrated in Figure E.1, Figure E.2, and Figure E.3 for three different scenarios.[141]

[141] Note that Figure E.1, Figure E.2, and Figure E.3 give only three examples of what can be a whole spectrum of possibilities of multiple consecutive voltage disturbance severities, durations, number of occurrences, and the timing between them.

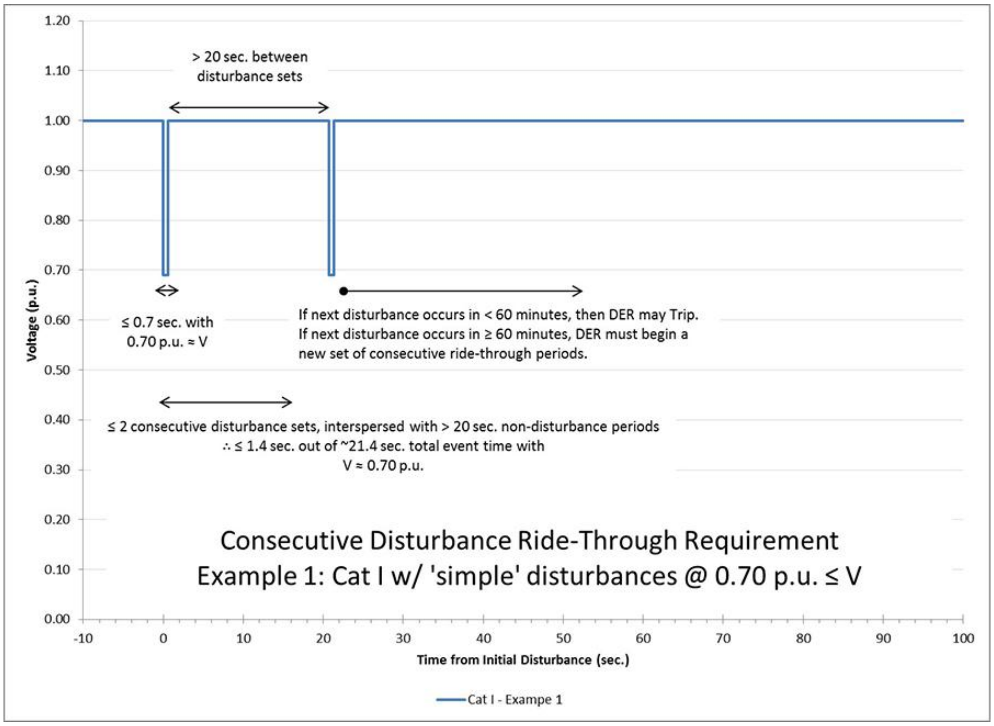


Figure E.1—Consecutive disturbance ride-through requirement, Example 1 for Category I

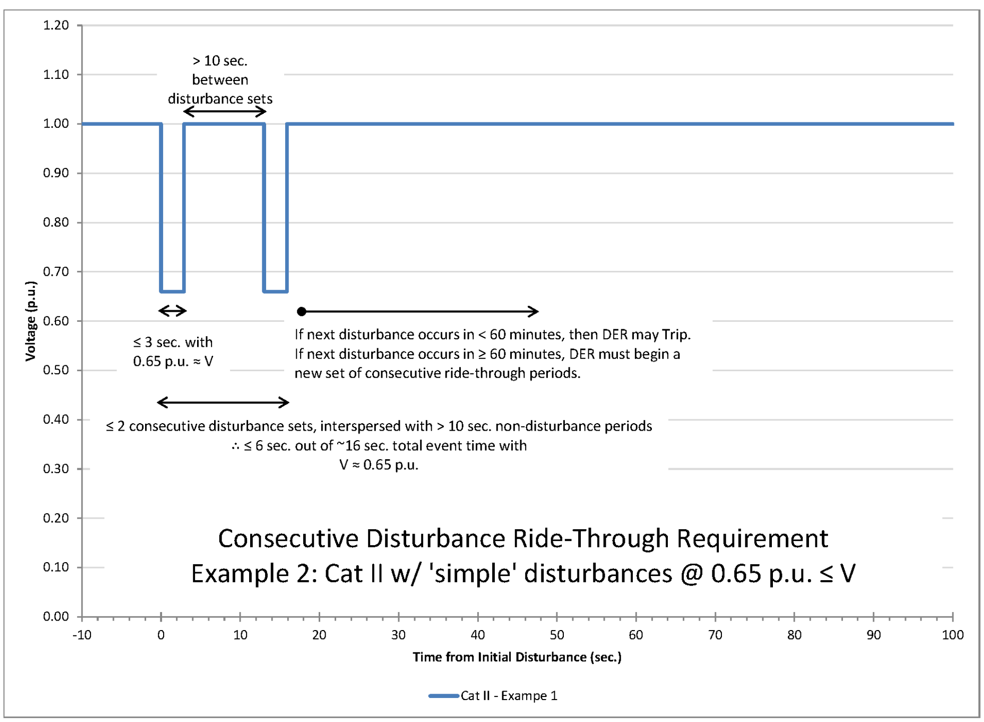


Figure E.2—Consecutive disturbance ride-through requirement, Example 2 for Category II

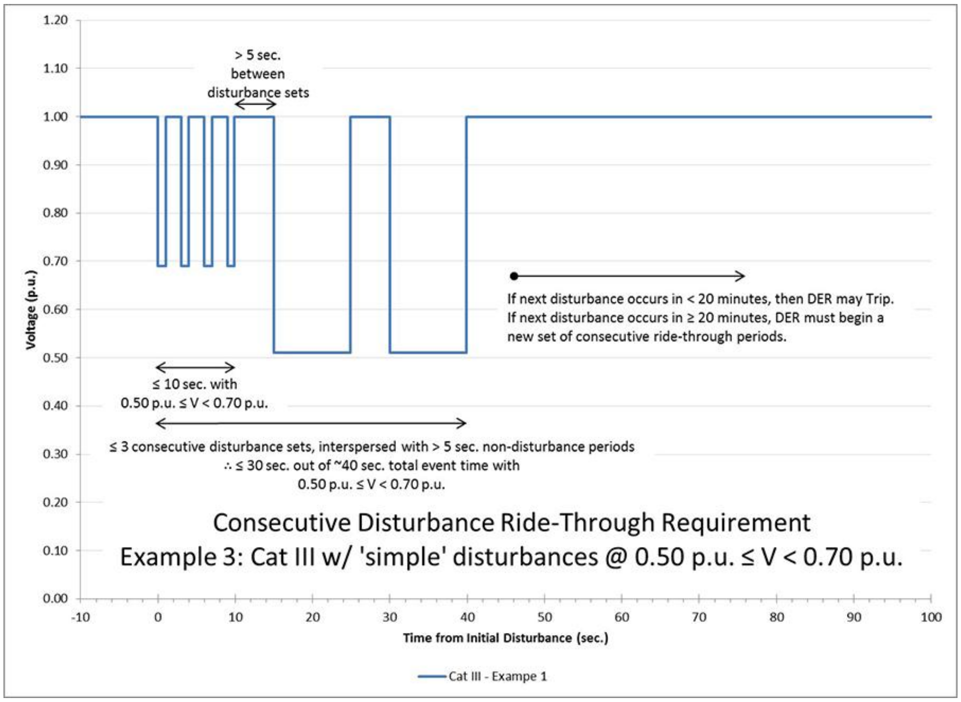


Figure E.3—Consecutive disturbance ride-through requirement, Example 3 for Category III

In the examples in Figure E.1, Figure E.2, and Figure E.3, note the differences in the severity and durations of the abnormal voltages (periods during active fault) and the differences in the number and duration of periods of relatively normal voltages in between (periods where fault is not active). The differences in the severity of the abnormal voltages experienced at a particular DER are due to the impedance of the fault that is occurring, the relative location of the fault, the DER, and other sources on the electric system, and the impedance matrix of the entire power system network. Obviously, these conditions are different for each fault that may occur, and for each DER experiencing the disturbances associated with any of those faults. The differences in the durations of the abnormal voltages are due to the different operating times of the applied fault protection in response to the conditions to which it is exposed. For faults on transmission systems and within substations, the typical current differential, directional comparison, and impedance (distance) protection schemes have high-speed or short, fixed, incremental response times, usually of less than one second and rarely longer than two seconds, and largely independent of the fault current magnitude (but rather the protection zone in which he fault occurs). For simpler time-overcurrent protection, different fault durations are caused not only by different time-current response selections at different protection installations, but also because different levels of fault current will exist for different faults (and thus different response times at the same installation), again due to different fault impedances and system impedances to different fault locations. Finally, the number and duration of periods of relatively normal voltages are due to the selected number of reclosing attempts and the selected reclosing interval times (open times) between each reclosure.

Where automatic reclosing is applied, common selections for a reclosing sequence include 1, 2, or 3 reclosing attempts, corresponding to a series of 2, 3, or 4 voltage disturbances for a persistent fault. Different reclosing equipment may offer even more possible reclosing attempts, but the selection of more than three attempts is not as common. A wide range of reclosing interval times (open times) is usually available for selection, from an “instantaneous” reclosure on the first attempt to mere fractions of a second between reclosures to many seconds between reclosures. Transmission reclosing delays are typically 30 s or longer except where “high speed” reclosing is used with a delay of approximately 0.5 s. Delays longer than 1 s but less than 30 s are not typically used at the bulk transmission level as there is risk of aggravating dynamic oscillations.

At the distribution level, not all reclosing devices have selectable reclosing interval times, hydraulically controlled reclosers being a prime example. Where reclosing interval times are selectable, common selections are approxomately 0.2 s to 30 s, although there is much more variation here depending on type of power system (e.g., transmission, distribution, in cross-country right-of-way or along public streets), types of faults typically experienced on that system (e.g., lightning, tree-related), and different utility philosophies and practices.

E.3 Unrelated faults

Another scenario of power system faults that can occur causing multiple consecutive voltage disturbances is when several different faults occur at different locations within an area and within a relatively short window of time. Rather than resulting from multiple reclosures into the same fault, this scenario of multiple different faults may be triggered by a large weather-related event hitting an area, such as numerous lightning strikes during a thunderstorm, severe wind events including tornados or hurricanes, or at the peak of an ice storm.

E.4 Intermittent faults

A third scenario of power system faults that can occur causing multiple consecutive voltage disturbances is an intermittent arcing fault. This type of "sputtering" fault may arc and extinguish itself multiple times without causing any fault protection to operate, either due to high fault impedance resulting in low fault currents that go undetected, or due to relatively rapid self-extinguishing before the fault protection has had enough time to respond. In many cases, this type of fault can continue in this way for a long time, sometimes burning clear and other times eventually evolving into a sustained short-circuit fault. This type of fault may occur at the distribution voltage level, but does not occur at transmission voltage levels.

E.5 Voltage oscillations

The disruption of power flow from generation sources to loads caused by transmission faults cause the synchronous generators in the system to accelerate or decelerate such that their electrical angle with respect to an ideal fundamental-frequency reference is shifted from its pre-fault steady-state value. When the fault is cleared, the generator angles swing to the original value, if the system configuration remains unchanged, or to a new steady-state value if lines, loads, or sources are removed in the process of clearing the fault. Similar to a pendulum displaced from its resting position, the angles do not go to the post-fault values and stop, but rather oscillate with a period of a fraction of a second to several seconds. The resulting system oscillations cause the magnitude of the voltage throughout the system to be modulated at this low frequency. Modulation of distribution substation voltage by the dynamic behavior of the transmission system is reflected down to the voltages experienced by DER connected to the distribution system. As a result, DER PCC voltage magnitudes will tend to oscillate after the clearing of a transmission fault, and these oscillations may cause the voltage to repeatedly transition between the normal and abnormal (potentially including both high- and low-voltage periods) a number of times over a period of a number of seconds. These oscillations typically will dampen out within ten seconds. From the DER perspective, the transitions from normal to abnormal voltage might appear as multiple disturbances. This standard addresses this by specifying ride-through on a cumulative time duration basis. A given dynamic event should be all within one disturbance set, and the DER must ride through up to the total duration specified in terms of severity and DER category.

Annex F

(informative)

Discussion of testing and verification requirements at PCC or PoC

The requirements of this standard apply either at the PCC or the PoC, depending on the aggregate nameplate DER rating and the average annual load in the Local EPS. Where requirements apply at the PoC, equipment type testing will be sufficient to verify conformance with most requirements, in most cases. However, for DER facilities, i.e., Local EPS that are large enough so that requirements apply at the PCC, equipment testing should be supplemented by additional compliance verification measures such as the DER evaluation and further commissioning tests defined in Clause 11. The same holds for any DER that use supplemental DER devices to meet the requirements of this standard. The concept of combined type test and DER evaluation is summarized in Table F.1.

Table F.1—High-level test and verification requirements when type tests are performed for DER unit(s) and not for DER system(s)

<table>
<tr><th colspan="2" rowspan="2">IEEE Std 1547
requirement XYZ</th><th colspan="2">Applicability of requirements</th></tr>
<tr><th>Point of DER connection (PoC)</th><th>Point of common coupling (PCC)</th></tr>
<tr><td rowspan="2">DER capability and conformance</td><td>Full
No Supplemental DER device needed</td><td>Type test
+
Basic commissioning test</td><td>Type test
+
Basic DER evaluation</td></tr>
<tr><td>Partial
One or more Supplemental DER device(s) needed</td><td>Type test(s)
+
Detailed DER evaluation
+
Detailed commissioning test</td><td>Type test(s)
+
Detailed DER evaluation
+
Detailed commissioning test</td></tr>
</table>

DERs should meet the general requirements for full and partial conformance testing and verification as follows (illustrated in Figure F.1):

a) For DER that meet requirements at the PoC per 4.2 and that are fully compliant with all requirements of this standard without the use of a supplemental DER device, DER should be type tested. A DER evaluation and commissioning test should not be required for compliance to this standard, except if Table 44 requires an evaluation or commissioning test. DER that are type tested with the use of a supplemental device are permitted as well.

b) For DER that meet requirements at the PoC per 4.2 and that are partially compliant with the requirements of this standard and that comply with all requirements of this standard in combination with supplemental DER device(s), DER should be type tested and a DER evaluation and commissioning test should be performed.

c) For DER that meet requirements at the PCC per 4.2, for both full and partial compliance, DER should be type tested and a DER evaluation and commissioning test should be performed.

d) Combinations of DER unit(s) and supplemental DER device(s) forming a system that are type tested as a DER system should not require a DER evaluation or commissioning test except if Table 43 or Table 44 requires DER evaluation or commissioning test.

e) In all other situations, a detailed DER evaluation and detailed commissioning test should be required.

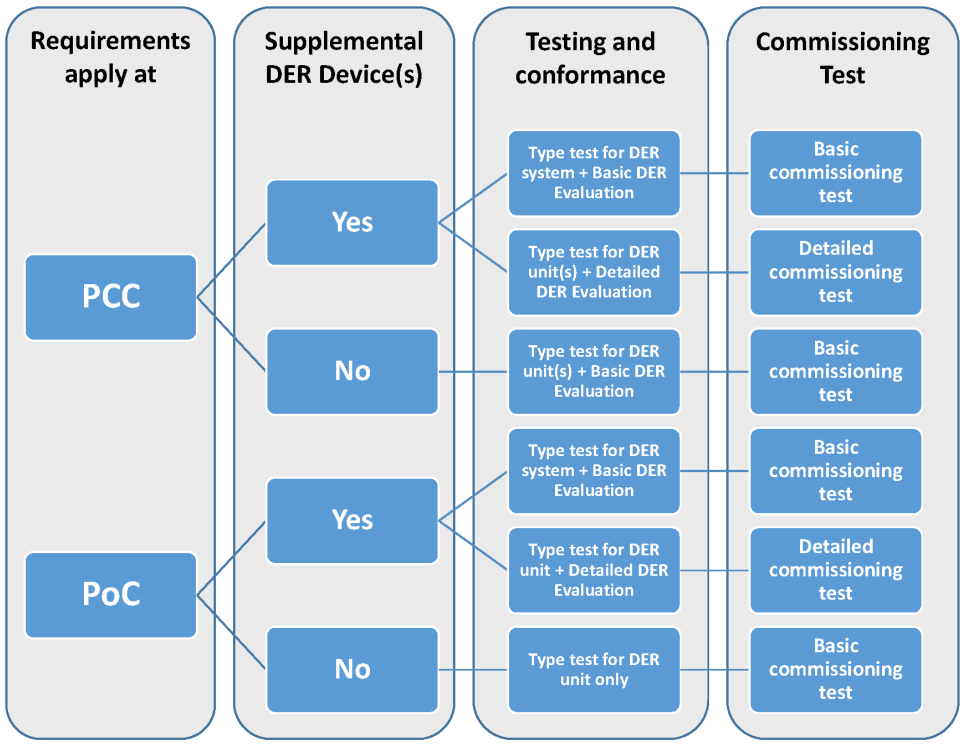


Figure F.1—Interconnection test specifications and requirements concept

DERs should meet the specific requirements for full and partial conformance testing and verification as specified in 11.3.2 and 11.3.3 by assignment of test and verification methods to the interconnection and interoperability requirements of this standard in form of a test matrix (an example of this is illustrated in Figure F.2).

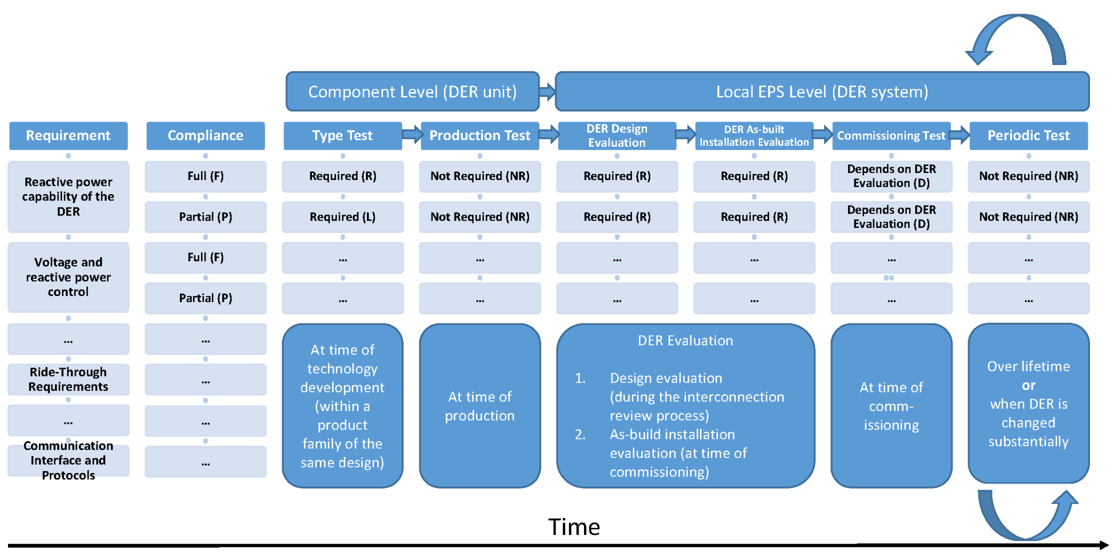


Figure F.2—Assignment of interconnection test specifications and requirements in test requirement matrix (Example)

Annex G

(informative)

Power quality (PQ) clause concepts and guidelines

G.1 Introduction

This annex provides additional information about power quality (Clause 7). It outlines the general principles and approach applied to update PQ requirements for DER in IEEE Std 1547. While there is growing body of experience related to distributed generation, almost all the previous standards development for power quality have been related to loads and not generators. A key consideration, and challenge, in setting PQ requirements for DER is performance dependence on the frequency response and relative capacity at the PCC. This is particularly true for voltage-related limits like RVC and flicker depending on the relative capacity of the PCC, and for production of harmonic currents depending on the harmonic impedance at the PCC. Short-term overvoltage related to the DER often depends on PCC loading and grounding details. There are potential interactions between the DER and the grid that may not be easy to predict in a study or remove from the certification process. Most of the discussions in this annex address these interactions relative to setting power quality limits.

G.2 Rapid voltage change (RVC) limits

IEC 61000-4-30:2015 defines RVC as a quick transition in rms voltage occurring between two steady-state conditions, and during which the rms voltage does not exceed sag/swell thresholds (10% above or below nominal voltage). Alternatively, IEEE Std 1453-2015 defines RVCs as changes in fundamental frequency rms voltage over several cycles. Both standards recognize RVC as an event that may not be captured by either steady-state or flickermeter measurements, yet may need to be considered for compatibility of end-use equipment and the electric grid.

On the end-user-side, beyond lighting, incompatibilities can manifest in torque transients on motor loads. On the utility-side, there have been incompatibilities between DER and distribution operating equipment such as voltage regulators, and involving reclosures and capacitors. In this context, RVC is included as a DER requirement. Some causes of rapid voltage changes include start-ups, inrush currents, and switching operation of equipment such as capacitor banks and transformers. An example of an RVC caused by transformer energization is shown in Figure G.1.

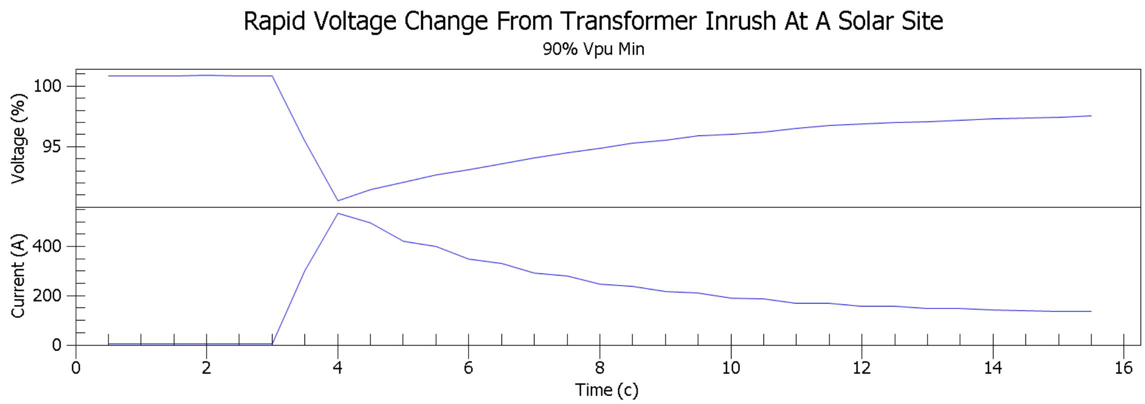


Figure G.1—Example rapid voltage change at 23 kV from transformer energization

The concern with transformer energizations associated with DER is not one-time events like plant commissioning, but if transformer energizations occur frequently.

System planning levels for RVCs are provided in Table G.1 adopted from IEEE Std 1453. The levels are defined in terms of maximum voltage deviation $\Delta V/V$ and the number of changes over time. It is important to note that the "system design planning levels" in this table are intended to represent aggregate limits of all sources of RVC at a point of evaluation (PCC or PoC). Since IEEE Std 1547 applies to DER, the most-strict limit of 3%, was adopted, applying a rationale to reserve some of the system capacity for other fluctuating installations, whether those installations are loads or DER. For purposes of individual DER performance evaluation, IEEE Std 1547 includes the ΔV% and a ramp rate that specifies a one-second time period. This individual DER limit is intentionally more specific than the planning level RVC definitions in IEEE Std 1453.

Table G.1—System design planning level for RVCs (IEEE Std 1453)

Number of changes (n)	**$\Delta V_{max}/V$) %**	
	≤ 35 kV	> 35 kV
$n \leq 4$ per day	5−6	3−5
$n \leq 2$ per hour and > 4 per day	4	3
$2 < n \leq 10$ per hour	3	2.5

In setting planning limits for aggregate RVC, the application of Table G.1 for screening or studies has some practical limitations. One limitation is that the DER rapid change performance is not likely known for inputting into prediction calculations. Various DER RVC performances are not expected to be documented during certification. For larger plants, it may be good practice to document and record plant energization, including waveforms, during commissioning. This can be useful if there are interactions and compatibility problems after commissioning.

Also, related to aggregate RVC limits, some planners will assume a step-voltage change at the PCC as if all DER connected to an Area EPS simultaneously have a 100% change in output power, from fully off or fully on. While this worse case is sometimes used in planning, its application to interconnection decisions is excluded in IEEE Std 1547. The rationale for exclusion is that the likely reason for all DER to trip simultaneously is in response to a grid event that takes voltage or frequency beyond ride-thru limits. Since the grid is outside normal operating limits in this case, it is inappropriate to apply an RVC limit for such a scenario.

Other tripping or power change scenarios would likely have less $\Delta V/V$ because of diversity. The number of changes per minute is also not predicable with various cases and sources of RVC. Therefore, specific design and operating environment of the DER should be considered to determine expected aggregate performance tests. Unexpected individual DER malfunctions may cause field problems and will also be difficult to predict in screening or studies. If there is a dispute about cause and effect, DER or grid, then field measurements and application of IEC/TR 61000-3-7 allocation methods may be helpful.[142]

G.3 Flicker limits

Flicker is the subjective impression of fluctuating luminance caused by voltage changes over a period of time, even if individual changes are not observed. Assessment methods for flicker, caused by highly fluctuating loads such as arc furnaces and welding are described in IEEE Std 1453. These methods are also defined in IEC/TR 61000-3-7. Included within this IEEE recommend practice is a table of indicative planning levels of flicker for different voltage levels, Table G.2. These levels are intended to account for the aggregate of fluctuating installations and are typically the basis for allocating emission limits to individual facilities using summation laws in the IEC document. Also, methods are provided to address transfer from HV to MV and between different PCCs. The allocation of emission limits to individual facilities (denoted as E_{Pst} and E_{Plt}) are set so that aggregate effects do not cause overall flicker at any PCC to exceed the adopted planning level.

Table G.2—Recommended planning levels (IEEE Std 1453)

	Flicker planning levels	
	MV	HV-EHV
L_{Pst}	0.9	0.8
L_{Plt}	0.7	0.6

Techniques normally used for fluctuating loads are applied in this standard to voltage fluctuations caused by fluctuating power generation. The limits for an individual DER facility are specified in 7.2.3. Based on the IEC method, allocations of emission limits to a DER are determined as a fraction of the planning level aggregate allocation. This allocation depends on the agreed capacity of the DER relative to the total available grid capacity at the point of evaluation. Specific calculations for this allocation at both MV and HV are provided in the IEC document. If the agreed capacity of the DER is relatively small compared to the grid capacity at the point of evaluation then a minimum allocation of flicker is provided in Table 25.

A key concept here, similar to RVC limits, is that IEEE Std 1547 addresses individual flicker limits and not the aggregate system performance, which is addressed by the recommended planning levels. Also, it is important to recognize that all these flicker limits have been developed based on basic 60 W incandescent lamps. Lamps of lower wattage may have more noticeable lumination changes with the same voltage environment. New types of lighting products generally perform better relative to flicker performance; however, there are exceptions.

In setting DER flicker requirements, consideration was given to the probability of producing voltage fluctuations and the likelihood of flicker complaints based on empirical or field experience to date. With exceptions, most properly functioning DER are not expected to produce pulsating power outputs that cause flicker complaints. For example, the range of known wind and solar resource variations (frequency and rate of change of the input power) have not been sufficient to result in flicker complaints. Also, other properly functioning DER such as gas-fired IC engines, fuel cells, or micro-turbines should not be naturally fluctuating sources prone to cause flicker. In these cases, screening for flicker, or attempting to predict it in a study, are not usually warranted.

On the other hand, certain power conversion technologies, such as particular wind turbine designs, have been known to cause flicker. Generally, these characteristics will be apparent either from certification, lack of certification, or in data required to be submitted in the application to interconnect. For example, IEC

[142] Users can also refer to IEEE Std 1453.1 [B16] since it is an adoption of the IEC technical report.

61400-21 defines flicker coefficients for certain types of wind turbines and provides methods to predict (screen or study) for potential flicker based on the grid characteristics at a PCC.

Despite best practices in processing DER applications, screening, studies, physical interconnection, and commissioning, unexpected field problems can happen. Flicker measurement (defined in IEC 61000-4-15) and analysis has proven useful in differentiating when a site is not functioning properly if there are unexpected interactions with the grid. The specifics on how to address field problems, determine responsibility, and allocate grid capacity are covered in IEC/TR 61000-3-7.

G.4 Current distortion limits

In this standard only current distortion limits are defined. The methodology for setting current distortion limits and for distortion measurement are adopted from IEEE Std 519. There are a few intentional, and notable, differences. The first is a change from total harmonic distortion (THD) limits, used in 2003, to total rated current distortion (TRD). The reason for this change is to capture inter-harmonics in the total distortion calculation. This method is described in a footnote in the normative requirements. The second difference from IEEE Std 519 is regarding the limits on even harmonics. The technical basis for tighter limits (i.e., 25% of odd harmonic limits) for even harmonics in IEEE Std 519 was researched. The key concern is the DC offset effect of even harmonics that have the potential to cause mis-operation of electronic switching by impacting zero crossing and other control logic. Practically, this DC offset effect is mainly caused by the 2nd harmonic and the effect of higher order harmonics diminishes rapidly. Additionally, the tighter limits for even harmonics for the higher order harmonics are found to fall outside the specified accuracy of PQ meters. Therefore, in this document, the limits for the higher order (8th and higher) harmonics have been relaxed to be the same as those for corresponding odd harmonics and the limits for the 2nd harmonic have not been relaxed at all. However, a stepped approach was taken for the for the 4th and the 6th and they have been relaxed to 50% and 75% of the corresponding odd harmonic limits respectively. It may be noted that limits for overall distortion have not been relaxed at all to act as the overall check on the distortion.

Voltage distortion limits are not defined for the DER and the current distortion limits are intended to be exclusive of harmonic currents due to harmonic voltage distortion present in the Area EPS without the DER connected. In the 2003 version of IEEE Std 1547, voltage harmonic tests were specified as an alternative performance measure, specifically for synchronous generator DER. The rationale for excluding voltage distortion limits in the case of synchronous generator DER in this standard are as follows:

A voltage distortion limit may be defined in the test procedure for synchronous generators. However, such a test definition is not considered to be a performance limit.

The meaning of voltage distortion limits of DER while operating grid-connected is unclear and could be misapplied. Defined DER current distortion limits would need to be adjusted for the test.

A very stiff grid may allow significant low-order current harmonic levels for a synchronous generator, and yet not allow significant voltage distortion to develop.

There are application concerns in relieving the DER of responsibility for current and sharing responsibility for voltage distortion in the grid.

G.4.1 Challenges of field testing for compliance

There are several challenges involved with harmonic compliance testing in the field vs in the lab such as the following:

a) Frequency response capabilities of typical utility grade PT and CT devices

b) Influence of Area EPS background voltage distortion
c) Influence of Area EPS harmonic impedances
d) Resolution of monitoring equipment in regards to low values of current or voltage

Inverter based generation often includes pulse width modulated converters that have switching frequencies of several kHz. It is feasible to anticipate measurable 3 kHz (50th order) harmonics on the generated output. Documented cases show harmonics above the 50th present on inverter based DER outputs. However, many utility-grade voltage and current sensors will not accurately reproduce frequency content above 2 kHz. These practical constraints need to be considered for any field verification as well as the requirement for special equipment adhering to accuracy limits to monitor an inverter-based site. The practice to accept type and production testing results, and then address any field anomalies on a case-by-case basis may be preferred.

Because of the challenges, it is difficult to confirm adherence to the higher order distortion limits in the field. Therefore, it is important to consider not only individual limits but also the TRD limit. The expectation and intention is that if the individual harmonics and inter-harmonics limits that are tabulated in Table 26 and Table 27 are met, and the TRD value is met, then obviously the current distortion ought to be acceptable. In contrast, if a higher order individual limit measures outside the limit in the field, but the TRD is within limit, consideration should be given to whether the sensor involved is capable of accurately reproducing the frequency in question.

G.4.2 Background voltage distortion challenges

The presence of background voltage distortion is to be expected. As such, the DER current distortion performance can be affected by voltage distortion that exists before the installation of the DER. The current distortion requirements are intended to be written in a manner such that DER will not to be held responsible for current distortion that results from background voltage distortion.

Most DER appear as a harmonic voltage source behind an impedance that is primarily defined by the DER's physical series impedance (output filter in the case of inverters, subtransient inductance in the case of rotating generators) at higher harmonic orders. At lower harmonic orders, at frequencies within an order of magnitude of an inverter's current regulator control bandwidth, the control characteristics may significantly affect the effective impedance. The flow of harmonic current, into or out of the DER, is the phasor superposition of the flow due to the external harmonic voltage distortion with the DER's internal source shorted, and the flow due to the DER's internal harmonic voltage source with the grid's harmonic voltage source shorted (i.e., an undistorted grid). Given these basic characteristics, harmonic current flow may occur even when the DER is not providing a source at the particular harmonic frequency, or harmonic current flow may be substantially altered by grid distortion at frequencies where the DER does provide a source.

The characterization of voltage-source inverter and rotating generator DER as harmonic current sources is a generally inaccurate concept with today's technology. In the past, line-commutated converter technology was in common use and influenced industry's practices for harmonic distortion limitation (such as the original IEEE Std 519). Despite its limitations, and due to the lack of a suitable alternative, a current limitation approach is retained in this standard to maintain consistency within the industry.

DER that meet current distortion limits when connected to an undistorted external system, such as during type testing, may exceed current distortion limits when measured in a field environment having voltage distortion. In those situations, the Area EPS operator will need to determine the appropriate resolution. Many times, such current distortion flows in the presence of background voltage distortion are only slightly beyond limits and therefore, immaterial to the cumulative voltage distortion of the Area EPS. Such cases are not likely to warrant the additional costs associated with study designed for differentiating the distortion caused by the Area EPS. However, it is possible for the DER to be in resonance with a system harmonic impedance, in which case the measured current distortion would be significantly beyond the acceptable limit and in need of mitigation.

G.5 Limitation of overvoltage

Overvoltages may occur when DER is islanded with a ground fault present on the islanded system. The potential for overvoltage depends on the characteristics of the DER, presence of any external ground sources, and the characteristics of the load remaining connected to the island. Evaluation of such overvoltages in the case of rotating generator DER is well defined by conventional analysis practices. For current-regulated sources, such as inverters, conventional fault analysis practices are inaccurate. The latter situation is described in detail in IEEE Std C62.92.6, with recommendations for alternate analysis procedures.

G.6 Related standards

The following standards are related to this annex and provided here for convenience:

IEC/TR 61000-3-7, Electromagnetic compatibility (EMC)—Limits—Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems.

IEC 61000-4-30:2015, Electromagnetic compatibility (EMC): Testing and measurement techniques—Power quality measurement methods.

IEEE Std 1453-2015, IEEE Recommended Practice—Adoption of IEC 61000-4-15:2010, Electromagnetic compatibility (EMC)—Testing and measurement techniques—Flickermeter—Functional and design specifications.

IEEE Std 1453.1-2012, IEEE Guide—Adoption of IEC 61000-3-7:2008, Electromagnetic compatibility (EMC)—Limits—Assessment of Emission Limit for the connection of fluctuating installations to MV, HV and EHV power systems.

IEEE Std C62.92.6-2017, IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part VI—Systems Supplied by Current-Regulated Sources.

Annex H

(informative)

Figures illustrating general interconnection technical specifications and performance requirements of Clause 4 to Clause 6

H.1 Informative figures related to 4.2 [Reference points of applicability (RPA)]

Figure H.1 and Figure H.2 relate to 4.2.

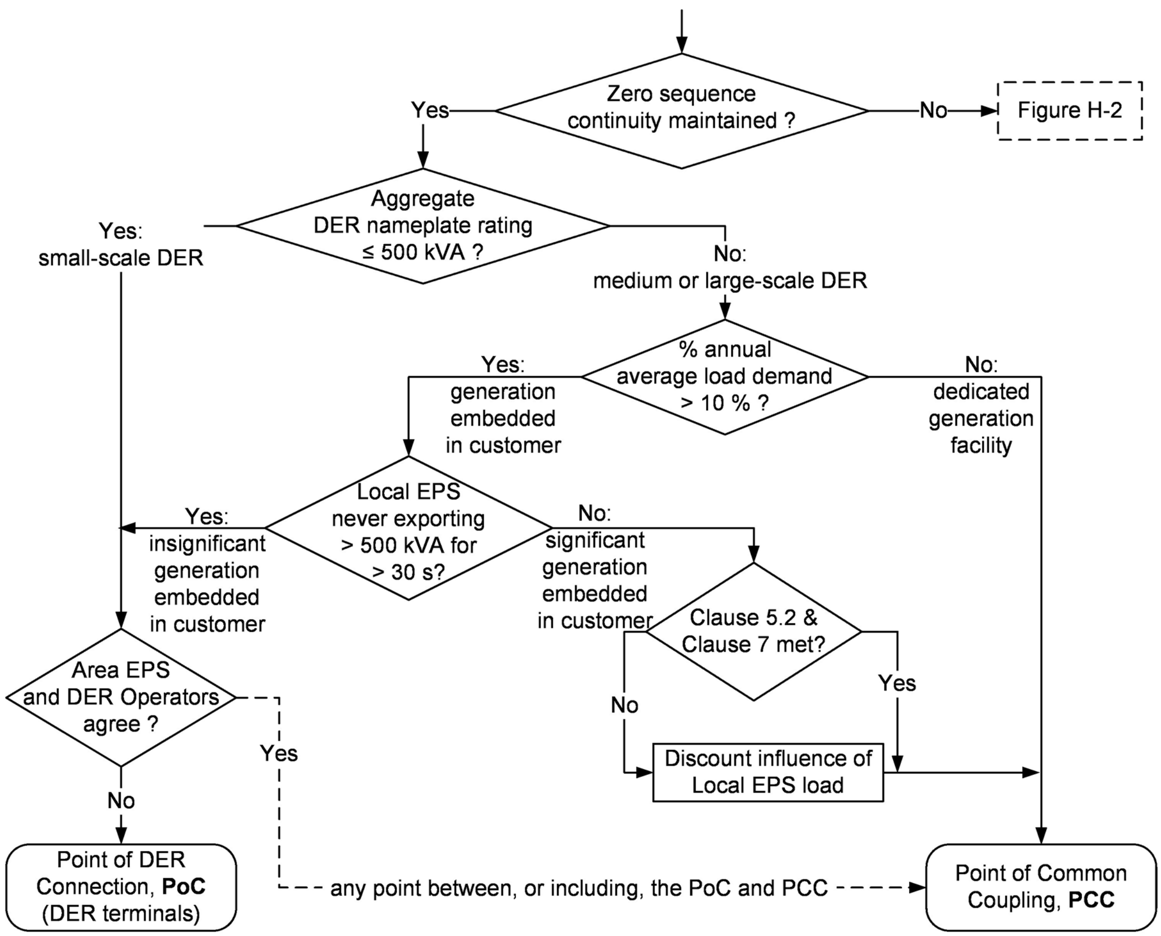


Figure H.1—Decision tree for reference point of applicability (RPA) for Local EPS where zero sequence continuity is maintained

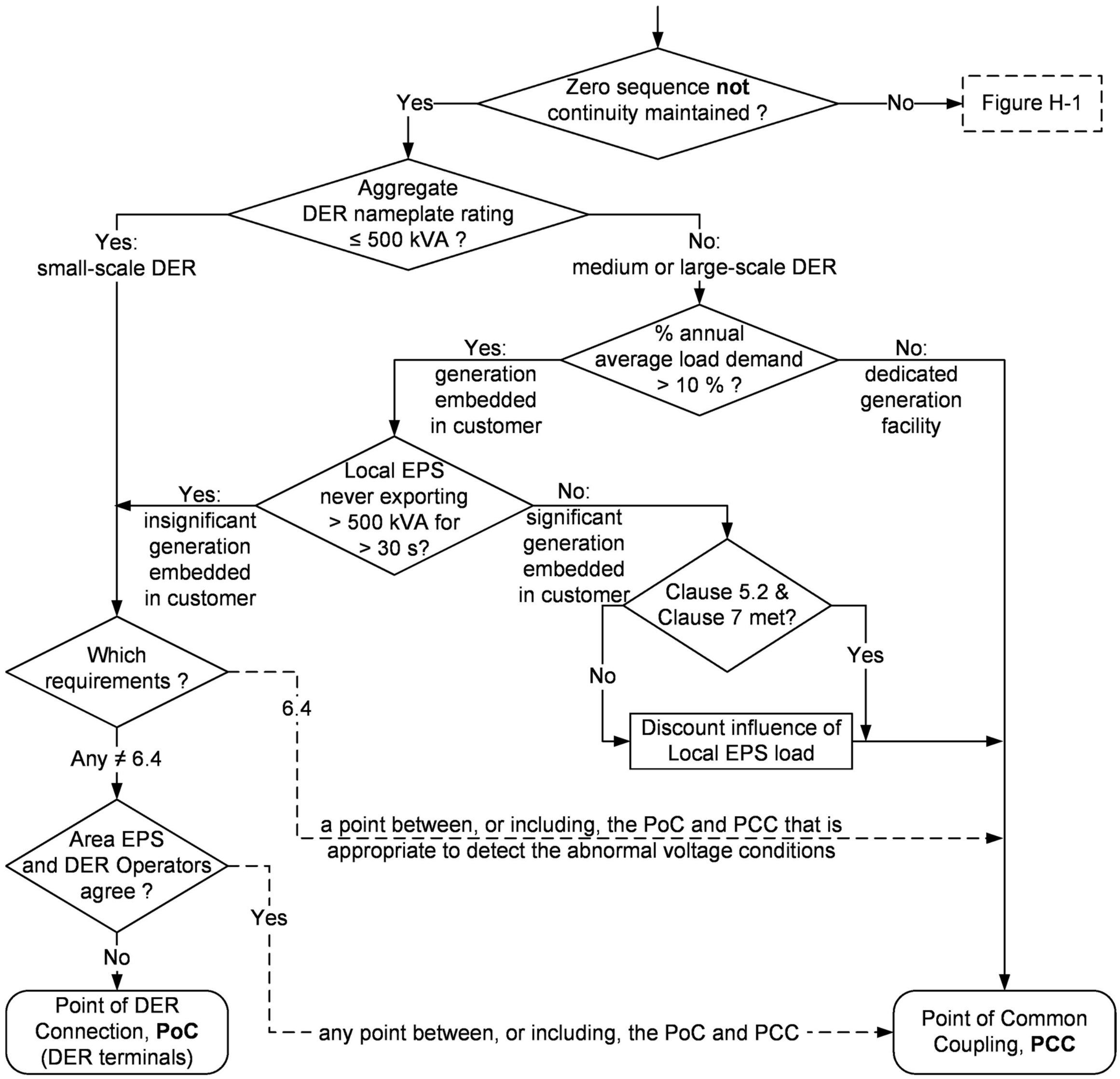
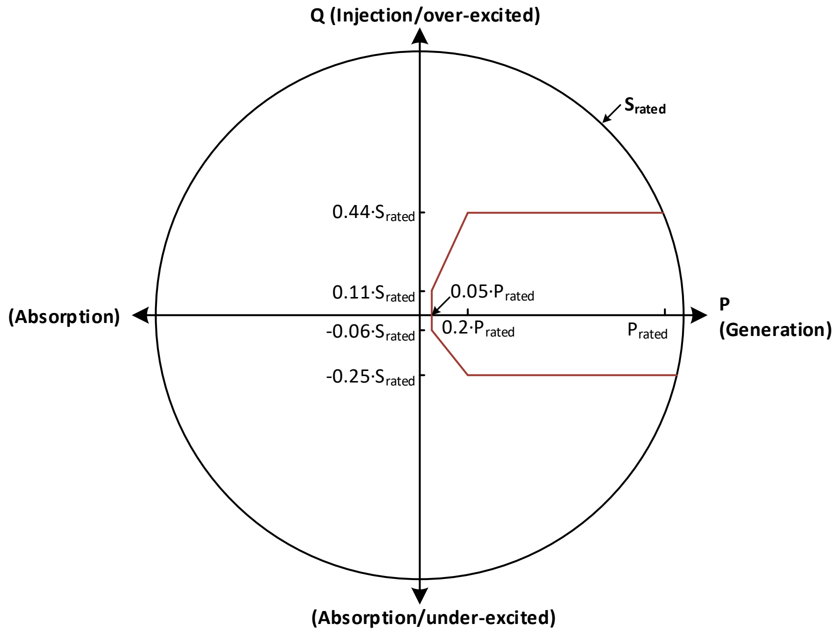


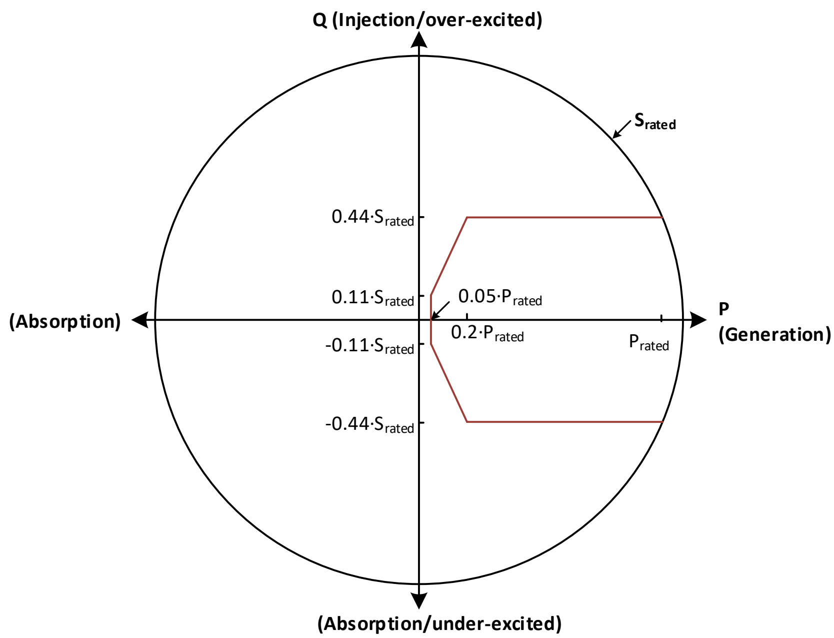
Figure H.2—Decision tree for reference point of applicability (RPA) for Local EPS where zero sequence continuity is not maintained

H.2 Informative figures related to Clause 5 (Reactive power capability and voltage/power control requirements)

Figure H.3 through Figure H.6 relate to Clause 5 of this standard.



Category A



Category B

Figure H.3 —Minimum reactive power capability of Category A and B DER

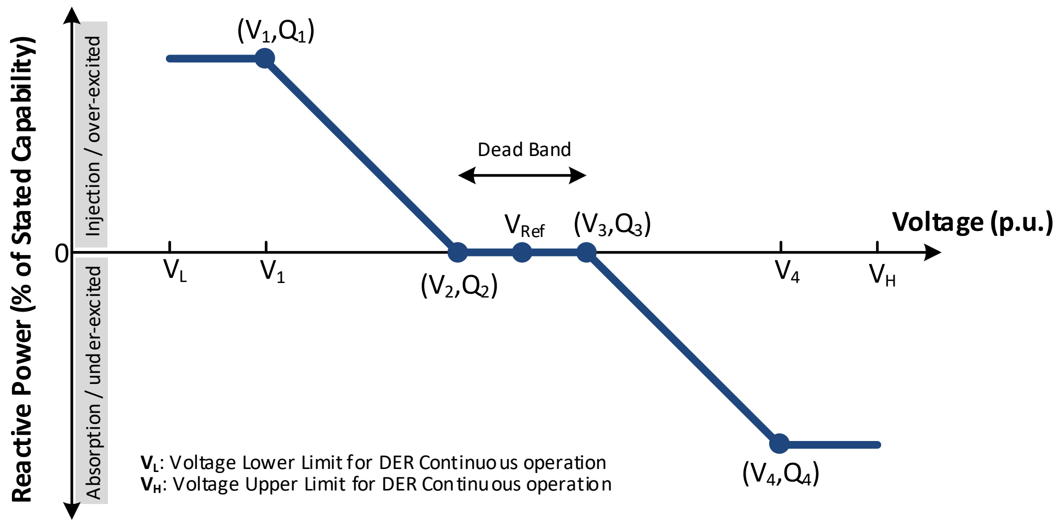


Figure H.4—Example voltage-reactive power characteristic

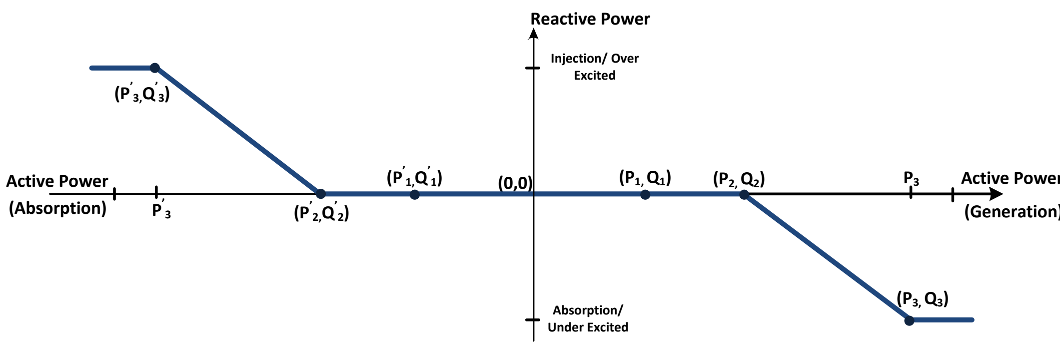


Figure H.5—Example active power-reactive power characteristic

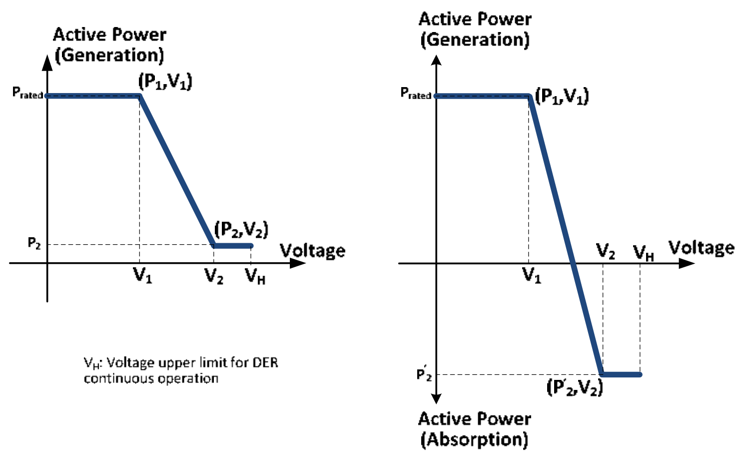


Figure H.6—Example voltage-active power characteristic

H.3 Informative figures related to Clause 6 (Response to Area EPS abnormal conditions)

Figure H.7 through Figure H.11 relate to Clause 6 of this standard.

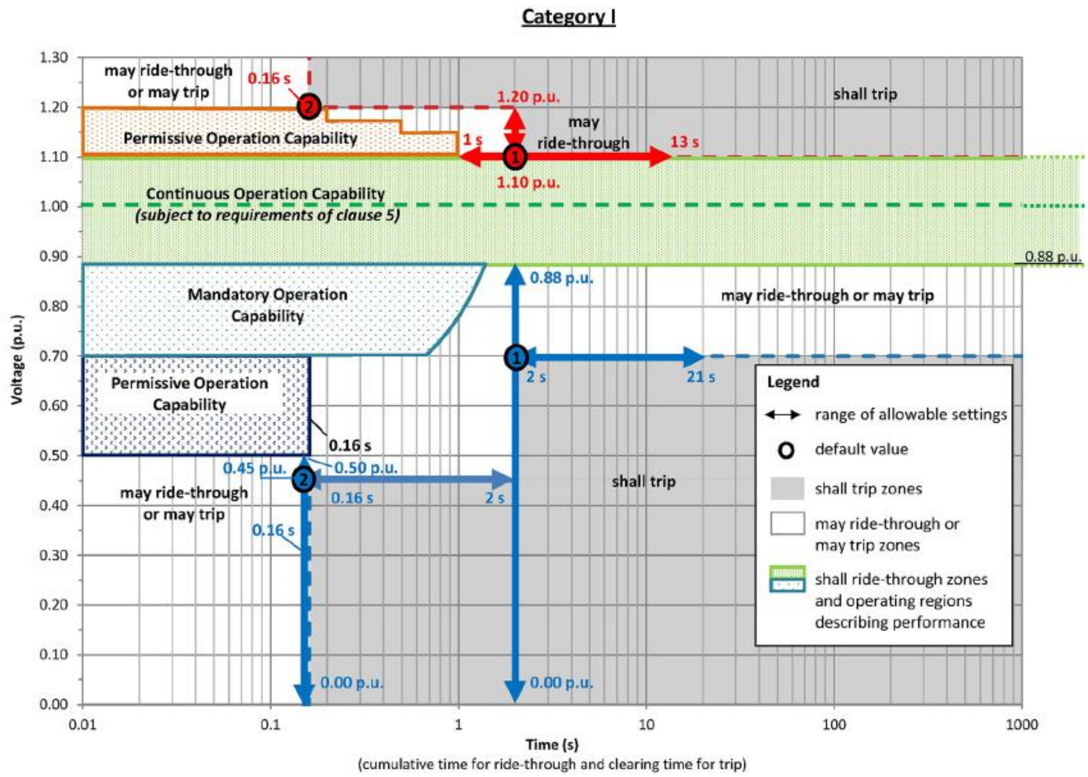


Figure H.7—DER response to abnormal voltages and voltage ride-through requirement for DER of abnormal operating performance Category I

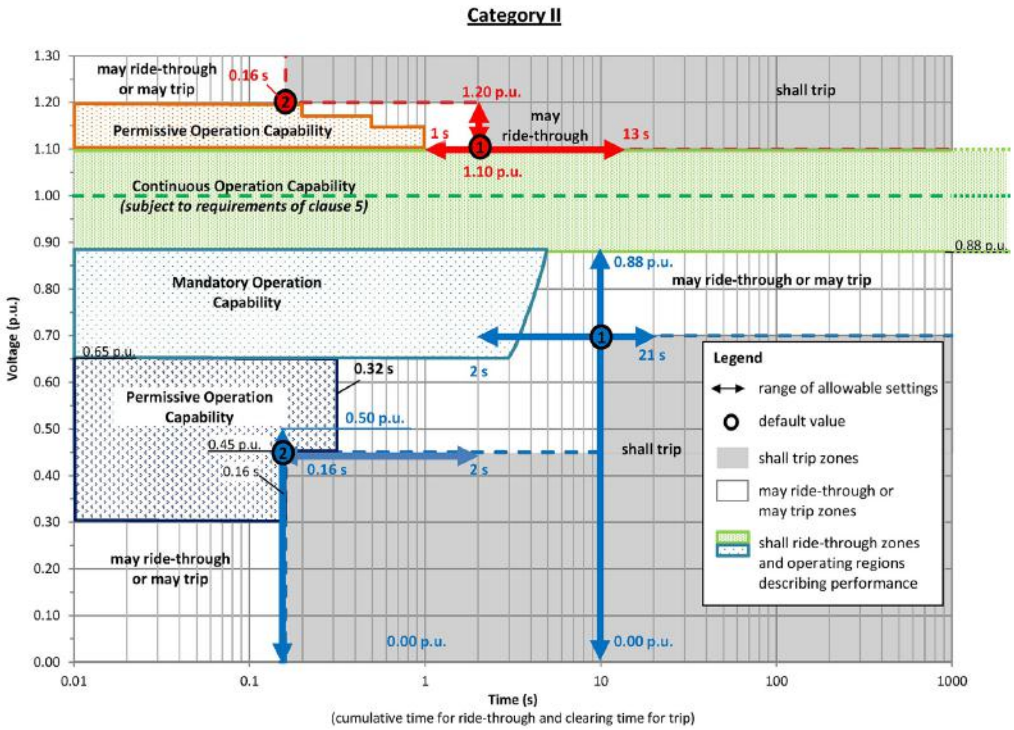


Figure H.8—DER response to abnormal voltages and voltage ride-through requirements for DER of abnormal operating performance Category II

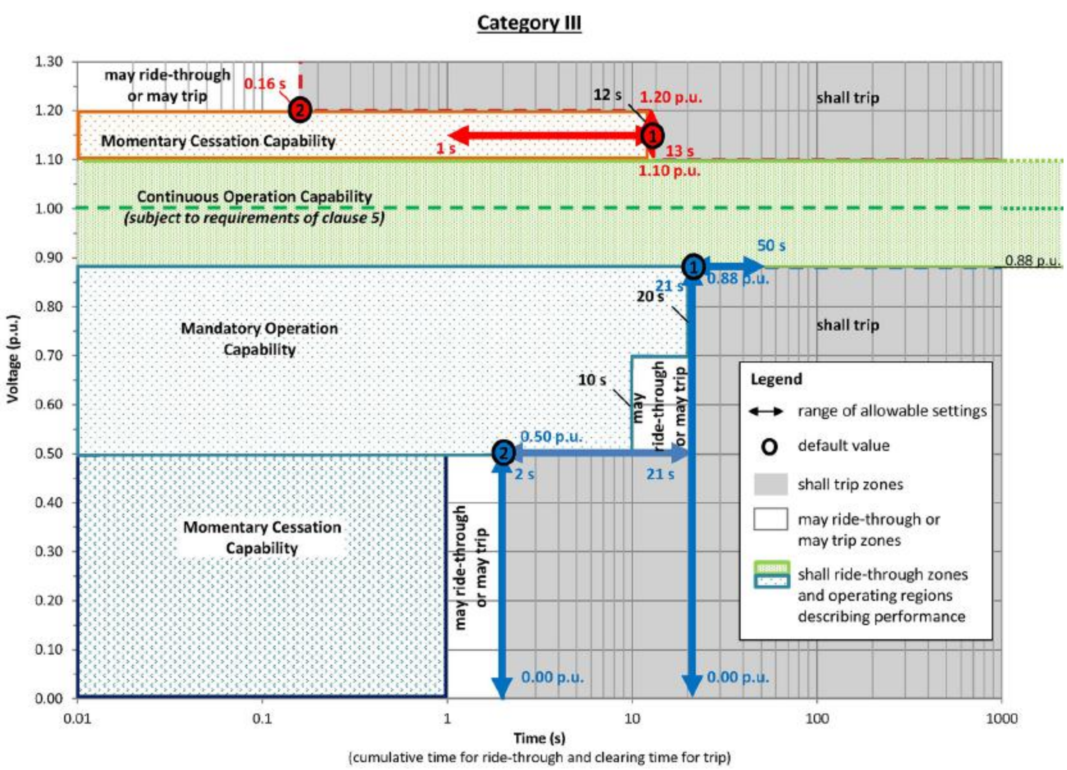


Figure H.9—DER response to abnormal voltages and voltage ride-through requirements for DER of abnormal operating performance Category III

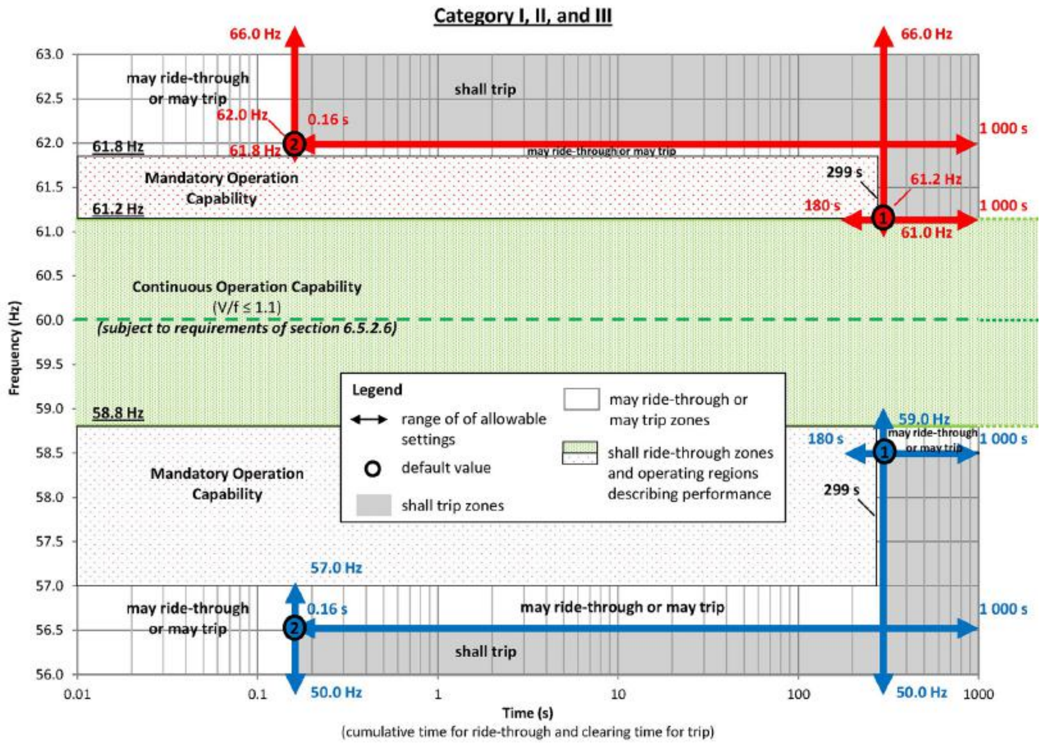


Figure H.10—DER default response to abnormal frequencies and frequency ride-through requirements for DER of abnormal operating performance Category I, Category II, and Category III

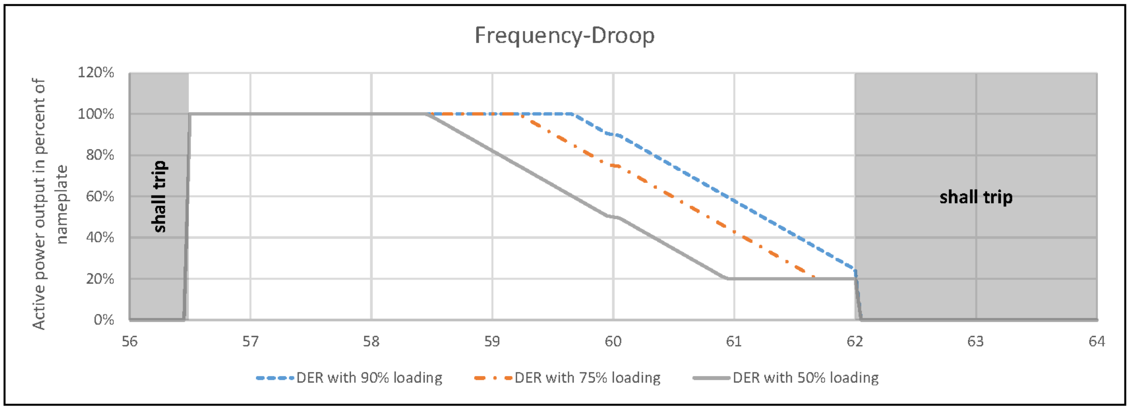


Figure H.11—Example of a three frequency-droop function curves with a 5% droop, 36 mHz deadband, and 20% minimum active power output for DER operating at different pre-disturbance levels of nameplate rating (50%, 75%, and 90%)

NOTE—A DER response during low-frequency conditions may be subject to *available active power* and the pre-disturbance dispatch level.