Considerations for Distributed Energy Resource Integration in Puerto Rico

DOE Multi-Lab Grid Modeling Support for Puerto Rico

Analytical Support for Interconnection and IEEE Std 1547-2018
National Renewable Energy Laboratory (Task 3.0)

David Narang, Michael Ingram, Xiangkun Li, Sherry Stout, Eliza Hotchkiss, Akanksha Bhat, Samanvitha Murthy, Jeremy Keen, Chinmay Shah, Murali Baggu, and Aadil Latif

National Renewable Energy Laboratory

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List of Acronyms

ACONER	Asociación de Contratistas y Consultores de Energía Renovable (Association of Renewable Energy Consultants and Contractors of Puerto Rico)
ASCE	American Society of Civil Engineers
DDEC	Department of Economic Development and Commerce
DER	distributed energy resource
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EPS	electric power system
FEMA	Federal Emergency Management Agency
IEEE	Institute of Electrical and Electronics Engineers
IRP	integrated resource plan
NEMA	National Electrical Manufacturers Association
NREL	National Renewable Energy Laboratory
OGPe	Office of Permit Management
OV	overvoltage
PREB	Puerto Rico Energy Bureau
PREPA	Puerto Rico Electric Power Authority
PV	photovoltaic
ReNCAT	Resilient Node Cluster Analysis Tool
RPS	renewable portfolio standard
SGIA	Small Generator Interconnection Agreement
SGIP	Small Generator Interconnection Procedures
UL	Underwriters Laboratory
UV	undervoltage
VAR	volt ampere reactive

Executive Summary

To ensure the sustainable long-term recovery of Puerto Rico's electric power grid from hurricanes María and Irma and to build capacity to manage future potential natural disasters in the most secure and resilient way, the U.S. Department of Energy (DOE) convened experts from multiple national laboratories to develop a comprehensive set of data, models, analytic tools, and studies, considering inputs from a wide variety of stakeholder groups, to support technically sound recommendations for Puerto Rico's energy investment decisions.

A resilient electric grid is vital to Puerto Rico's security, economy, and way of life, and it will provide the foundation for essential services that people and businesses on the island rely on every day. This report shows progress for a grid modeling task under the DOE-sponsored project that is a collaboration among the National Renewable Energy Laboratory (NREL) and other national laboratories.

In Phase 1 of the multilab effort to support Puerto Rico's recovery, NREL provided the utility company Puerto Rico Electric Power Authority (PREPA) recommendations for a new framework of interconnection standards to accelerate the integration of utility-scale, transmission-connected renewable electrical generation and energy storage that ensure cross-technology compatibility and enable high deployment levels without compromising grid reliably, safety, or security.[1]

This Phase 2 report focuses on the interconnection of distributed energy resources (DERs) to the electric distribution system in Puerto Rico. This report is intended to familiarize the reader with Puerto Rico's distribution infrastructure and operational practices and procedures that are relevant to DER interconnection. The report also provides considerations for streamlining the interconnection process given the expected increase in deployments resulting from Puerto Rico's renewable portfolio standard (RPS) goal of 100% renewables by 2050. Accordingly, the report identifies considerations and concerns associated with the increase in intermittent generation, strategies for DER interconnection best practices, and the potential use of the latest technological solutions identified in the latest revision of the Institute of Electrical and Electronics Engineers (IEEE) 1547-2018 interconnection standard.

An important goal of the project was to identify ways to improve the physical resilience of installed DERs, and this discussion with recommendations is found in Chapter 0.

The work described is undertaken by NREL under Phase II, Task 3 of the DOE Multi-Lab Grid Modeling Support for Puerto Rico. This is one of a series of reports describing the DOE multi-lab efforts undertaken. Other tasks in this phase include quantification of the solar energy resource in Puerto Rico for utility-scale photovoltaics (PV) (Task 1), energy production and reserve simulations and reliability assessment of renewables integration (Task 2), and cost-

[1] See "Interconnection Requirements for Renewable Generation and Energy Storage in Island Systems: Puerto Rico Example" by Vahan Gevorgian, Murali Baggu, and Dan Ton, presented at the 4th International Hybrid Power Systems Workshop, Crete, Greece, May 22–23, https://www.nrel.gov/docs/fy19osti/73848.pdf.

benefit analysis using the System Advisor Model with codevelopment of planning tools for the energy sector (Task 4).

Chapters 1 and 2 of this report describe the context for the interconnection of DERs in Puerto Rico. This material is intended to familiarize the reader with the complexity of this context, including the distribution infrastructure and operational practices and procedures that are relevant to DER interconnection as well as the relevant drivers in public policy and the regulatory framework.

Chapter 2 describes the expected changes to the energy infrastructure given the changing landscape for DERs given the expected increase in deployments resulting from Puerto Rico's aggressive RPS goal of 40% renewables by 2025 and 100% by 2050.

Chapter 3 provides technical considerations of and concerns associated with the increase in intermittent generation, strategies for DER interconnection best practices, and potential use of the latest technological solutions identified in the latest revision of IEEE Std 1547-2018.

Chapter 4 provides considerations and recommendations for streamlining the interconnection process.

Chapter 5 focuses on efforts for increasing the resilience of DER systems based on a review of the impacts of Hurricane María on solar PV installations. The material presents a discussion of failure modes, best-practice construction, siting, and operational options to reduce the impacts of future events.

Chapter 6 presents comments from key stakeholders on topics related to distributed generation interconnection and the Puerto Rico energy and policy landscape.

Table ES-1 lists key observations and recommendations organized by category: DER interconnection (technical and nontechnical), physical resilience, and workforce engagement.

Table ES-1. Key Observations and Recommendations

Category	Gap/Issues	Opportunity/Solutions
DER interconnection (technical)	Lack of requirements for utilization of reactive power capability; lack of requirements for voltage and frequency ride-through	Adopt and implement IEEE Std 1547-2018. Develop training and education on the standard and updated related technical requirements to interconnection rule and procedure.
	Need for additional engineering studies and analysis on microgrid integration and operation	Puerto Rico stakeholders should consider planning, coordination, communications, and control strategies for the numerous islanded systems potentially expected.
	PREPA does not specify requirements for interoperability.	Requirements should be reviewed to determine whether new interoperability guidance is appropriate or required. Special note should be given to long-term energy policy and market goals. Determine communications, monitoring, and control strategy for DERs in the context of grid services, customer participation, aggregation, community solar, and various stakeholders, for example.
DER interconnection (nontechnical)	Lack publicly available studies' costs greater than 10 kW	Provide estimated costs or ranges of cost for supplemental studies, greater than 10 kW. Although studies for distributed generation systems with generation capacities of 10 kW are specified in the Regulation ($300), systems with capacities more than that are not specified. PREPA has established standard costs.
	Lack of interconnection process efficiency	Eliminate redundant document-handling steps. Process revision should incorporate automation of document-handling steps by providing the client an option to submit all documents through the online portal.
Physical resilience	Lack of attention to storm-hardening	Develop and use checklists for pre-hurricane preparation to secure solar equipment. Require geotechnical studies on utility-scale array foundations located in hurricane zones.
Workforce engagement	Lack of knowledge, understanding, and experience with these topics	Create workforce development strategies to improve implementation and build capabilities.

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Introduction

In response to hurricanes Irma and María and the subsequent need to ensure the long-term recovery of Puerto Rico's electric power grid in the most secure and resilient way, the U.S. Department of Energy (DOE) convened experts from many national laboratories to develop a cohesive set of recommendations based on the expert opinion of the varied stakeholders to ensure a strong technical rationale for Puerto Rico's energy investment decisions. A resilient electric grid is vital to Puerto Rico's security, economy, and way of life, and it will provide the foundation for essential services that people and businesses on the island rely on every day. This report shows progress for a grid modeling task under the DOE-sponsored project that is a collaboration among the National Renewable Energy Laboratory (NREL) and other national laboratories.

In Phase 1 of the multilab effort to support Puerto Rico's recovery, NREL provided recommendations for a new framework of interconnection standards to accelerate the integration of utility-scale renewable electrical generation and energy storage that ensure cross-technology compatibility and enable high deployment levels without compromising grid reliably, safety, or security.

This report, as part of the DOE Phase II multilab effort, is focused on the distribution system. There is increased interest in Puerto Rico to determine how distributed energy systems can benefit the electric system, and in April 2019, Puerto Rico revised its renewable portfolio standard (RPS) to a goal of 40% renewables by 2025 and 100% by 2050 (P.R. Law 17). Based on this goal, Puerto Rico's share of renewable generation, especially photovoltaic (PV) generation, at both the transmission and distribution level is expected to increase.

Objectives of this Phase 2 report are to:

1. Identify technical issues for integrating the expected increase in distributed generation, strategies for distributed energy resource (DER) interconnection best practices, and potential adoption of the latest revision of the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547-2018 interconnection standard.
2. Describe the context for the safe and efficient interconnection of electric generation resources (i.e., DERs) to the electric distribution system in Puerto Rico with an intent to familiarize the reader with Puerto Rico's distribution infrastructure and operational practices and procedures that are relevant to DER interconnection. Topics include the overall energy ecosystem, the regulatory structure, renewable energy policy, energy stakeholders, and distribution infrastructure.

Note that the discussions of relevant parts of the integrated resource plan (IRP) and bulk power system are intended only to provide context for DER capabilities under high shares of renewable generation and in certain cases to compare technical requirements.

Intended Audience

The intended audience for this report includes the Puerto Rico Electric Power Authority (PREPA); the Puerto Rico Energy Bureau (PREB); other regulating and certification bodies, such as the Department of Economic Development and Commerce (DDEC); and other stakeholders in the Commonwealth of Puerto Rico that might benefit from the material and analysis presented, including DER developers, owners, vendors, installers, and universities, as well as stakeholders on the mainland, including the DOE project management team overseeing this effort, other team members either at NREL or at the other national laboratories, nonprofits, and university researchers who might find the material complementary to their analyses.

Distributed Energy Resource Interconnection Stakeholder Process

Technical standards such as IEEE Std 1547 can help reduce the overall cost of electricity asset design and operation in many ways, including by implementing uniformity of design, minimizing costly custom solutions, and sharing best practices. The standard is intended to be used in conjunction with others to address other important aspects of interconnection, as shown on the bottom right in Figure 1. This figure also illustrates that interconnection standards fit into a broader set of technical requirements that are tailored to meet the needs of the customer's intended use of the technology as well as the requirements placed by the electrical system operator.

Technical requirements comprise only a portion of the rules and procedures needed for interconnection. Interconnection rules and procedures might also include requirements related to broader energy policy goals and regulations or energy market considerations. In areas with high targets of renewable generation that could include large shares of inverter-based resources, attention is also given to these at the transmission level.

Changes to interconnection rules and processes as well as associated technical requirements are often driven by evolving energy policy goals and market trends, but consideration for updates also might be needed because of advances in technology, changes in deployment patterns, revised best practices, or updates to technical standards.

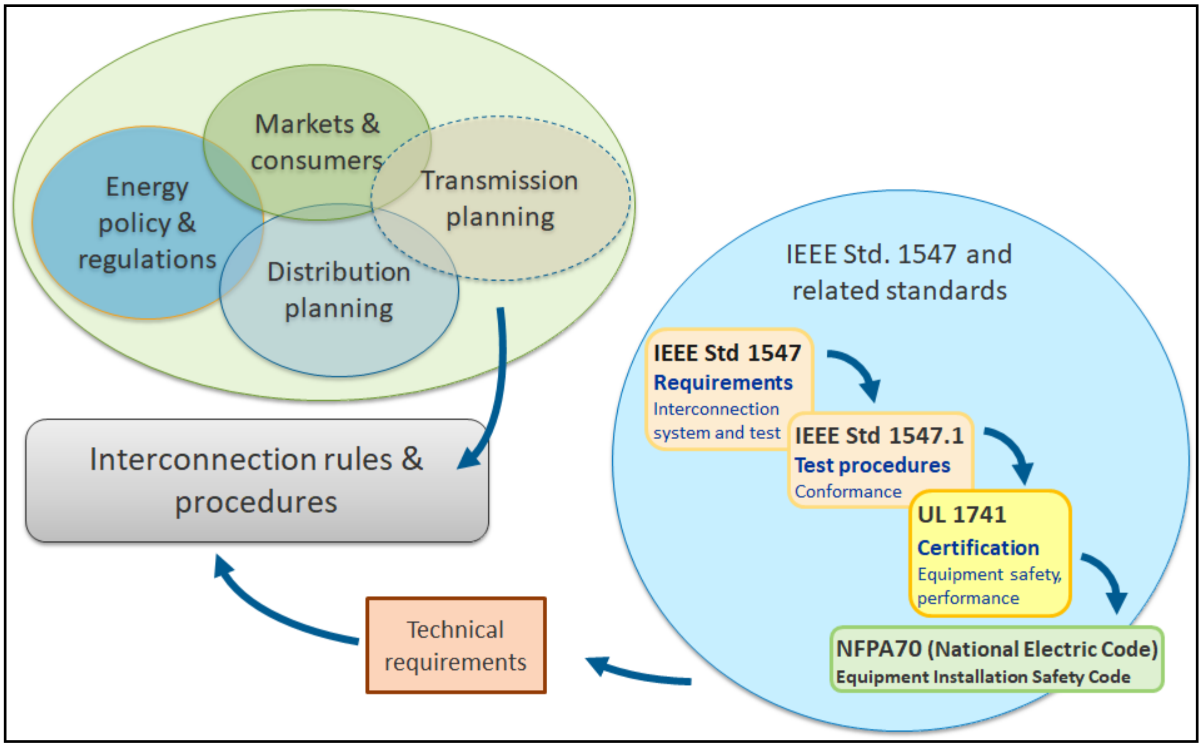


Figure 1. Context for DER interconnection rules and procedures

This broader context for DER interconnection and the entities that embody key decisions are acknowledged in IEEE Std 1547-2018. Related key terms are defined in the standard, and specific references are made throughout the standard. These terms and relationships are illustrated in Figure 2.

Starting on the bottom right, at the facility level of the DERs, the authority having jurisdiction has rights to inspect and approve of the design and construction. In the mainland United States, this role is often filled by city or county inspectors. In Puerto Rico, this role is filled by the Office of Permit Management (OGPe by its Spanish acronym) and under some limited instances by PREPA.

At the distribution system level, several entities are critical to the interconnection process. The Authority Governing Interconnection Requirements is the entity that codifies, communicates, administers, and enforces DER interconnection policies and procedures. Examples of this are state regulatory agencies, public utility commissions, municipalities, or cooperative boards of directors. In Puerto Rico, this is PREB; however, policies and procedures are also codified in law by the Puerto Rico Legislature in Act No. 57-2014 and Act No. 17-2019.

In addition to the Authority Governing Interconnection Requirements, the area electric power system (EPS) operator maintains, manages, and operates the distribution system and is also responsible for developing the DER interconnection technical requirements. In Puerto Rico, this is the role of PREPA.

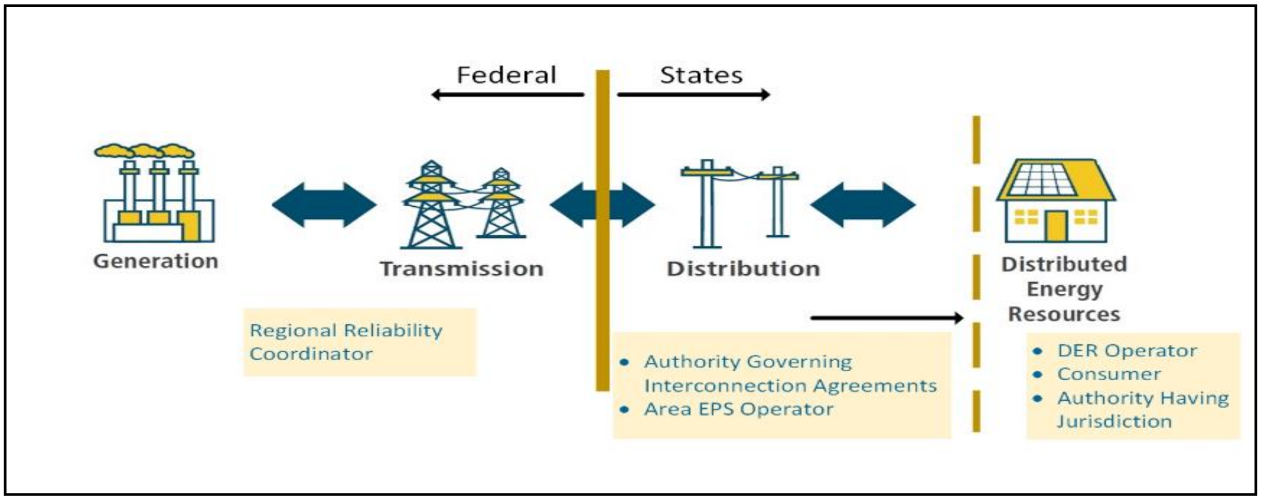


Figure 2. Entity jurisdictional boundaries and key terms

At the transmission and generation (i.e., bulk power) level, the regional reliability coordinator maintains the real-time operating reliability of the bulk power system in their reliability coordinator area. In areas that have high targets of renewable generation that could include large shares of inverter-based resources and/or large amounts of distributed generation, regional reliability coordinators across the mainland United States are paying increasing attention to these in planning studies. In Puerto Rico, PREPA has the role of a regional reliability coordinator.

In an interconnection, certain technical requirements are designed, very specifically, to meet the needs of an area EPS operator. These could be because of the area EPS electrical configuration; area EPS operator distribution operation practices; decisions by the area operator on electrical safety, power quality, and protection coordination; specific requirements for testing and certification; and requirements for voltage regulation and communications or other interoperability or supervisory control and data acquisition system integration requirements. These types of technical requirements are in large part at the discretion of the area EPS operator because they directly affect the safety and operation of the distribution system. In IEEE Std 1547-2018, many DER requirements fall into this category, including clauses on the prevention of unintentional islanding and power quality. These types of requirements are shaded blue in Figure 3. The area EPS operator is also shaded in the same color to indicate that these are generally the direct responsibility of the area EPS operator; and, generally, input on these requirements is not required from other entities.

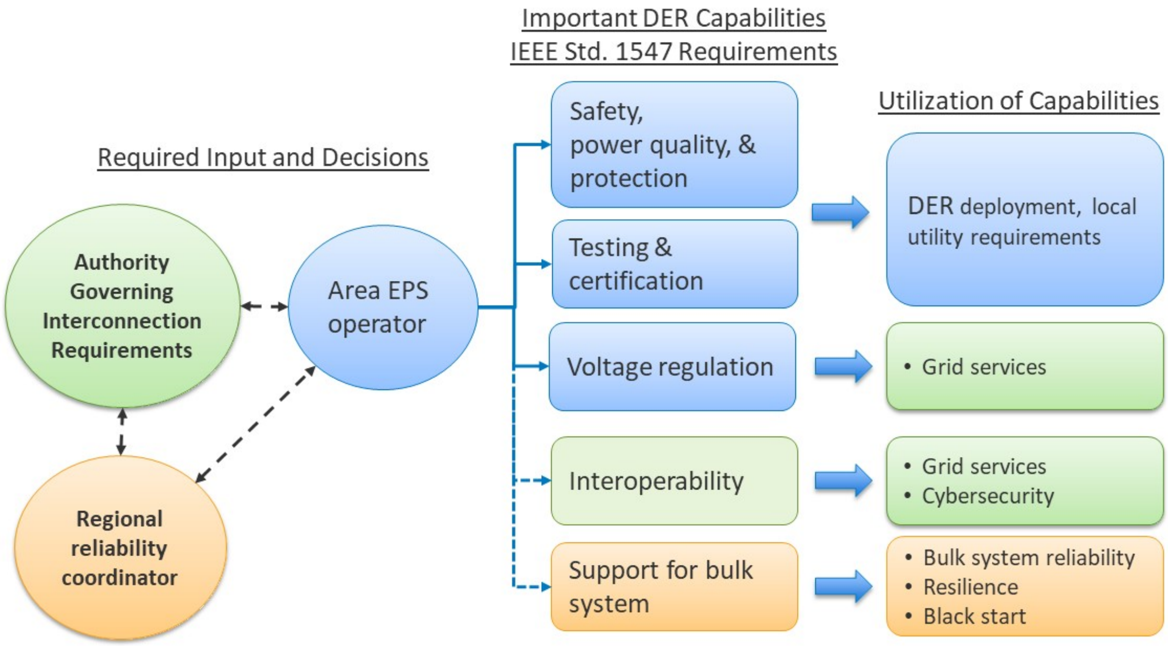


Figure 3. Context for interconnection technical requirements

Implementing certain capabilities such as voltage regulation and interoperability could have implications beyond the strict scope of IEEE Std 1547—for example, grid modernization policy goals and strategies, market strategies for enabling aggregated grid services from DERs, the integration of DER into DER management systems or advanced distribution management systems, communications with aggregators and customer-sited devices, and cybersecurity framework and posture. Because of this, the standard expects that decisions to enable and implement these technical capabilities shall have input not only from the area EPS operator but also the Authority Governing Interconnection Requirements. The Authority Governing Interconnection Requirements could choose to solicit input from a broader set of stakeholders via public workshops and meetings.

In the revised IEEE Std 1547 standard, DER capabilities for grid support of the bulk power system under abnormal voltage and frequency conditions are now mandatory. In most areas of the United States, enabling these capabilities has implications that extend well beyond the purview of the area EPS operator (e.g., bulk system reliability and resilience, black start), and for this reason, the standard expects coordinated discussion will take place between the area EPS operator, the Authority Governing Interconnection Requirements, and the relevant regional reliability coordinator(s). This context is illustrated in Figure 3. Note that in the case of Puerto Rico, PREPA has the role of both the area EPS operator and the regional reliability coordinator.

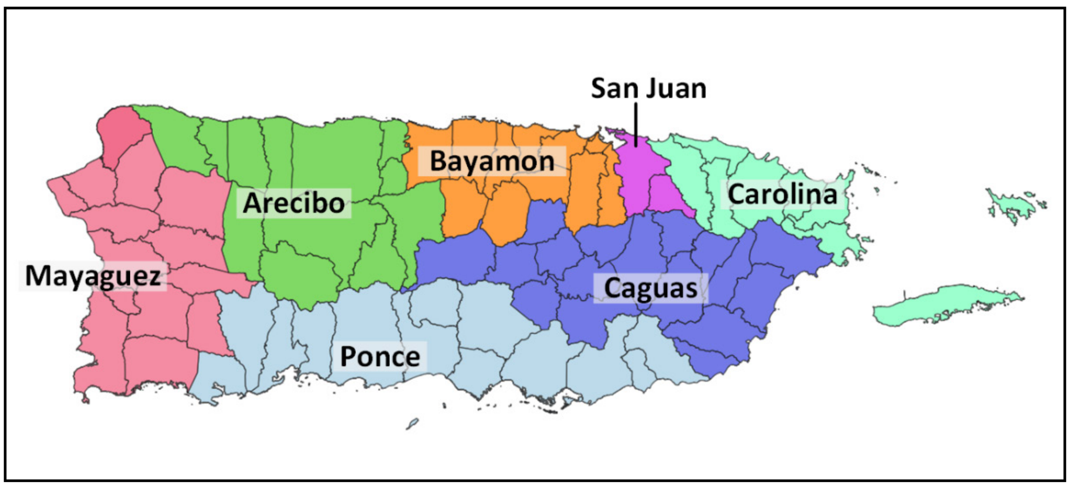
1 Background

This chapter provides reference material on Puerto Rico's current load and generation as well as distribution system infrastructure.

1.1 Electric System Overview

The electricity needs of the Commonwealth of Puerto Rico are served by PREPA. PREPA is the government-owned electric utility that is responsible for electric generation, transmission, and distribution infrastructure and operations. PREPA serves approximately 1.5 million customer accounts, representing a total population of roughly 3.2 million Puerto Ricans (PREPA 2019a).

PREPA divides Puerto Rico into seven administrative regions, as shown in Figure 4. All distributed generation interconnection applications are submitted to the Distribution Engineering Department of the administrative region where the distributed generation system is to be installed. If a supplementary study is not triggered, the regional office will process the interconnection request; otherwise, the interconnection application is sent to the Distribution System Planning and Research Department in San Juan. This department will notify the regional office of the results of the supplementary study. If upgrades to the distribution system are necessary and the client agrees to proceed with the interconnection process, the Distribution Engineering Department of the specific administrative region will notify the relevant districts under its jurisdiction to carry out the required feeder upgrades or adjustments.



Source data: Puerto Rico Government Open Data Portal. n.d., PREPA 2019c

Figure 4. PREPA administrative regions

Based on information collected at the U.S. Energy Information Administration (EIA), PREPA owns 80% of the generation capacity, 16% is served by independent power producers under power purchase agreements, and the remaining 4% capacity is from renewables power purchase agreements (PREPA 2019a). Most generators use petroleum fuels (Bunker C and Diesel, depending on the generating unit) as the fuel source.[2]

Residential customers account for 38% of the energy sales. Retail costs for electricity for residential customers are an average of 19.72 cents/kWh (EIA 2019a). As noted, this sector has a keen interest in developing increased resilience. According to conversations with solar installers and PREPA engineers at a workshop in April 2019, there has been a sharp increase in customer requests for distributed energy systems that couple PV generation with energy storage. It is currently unclear whether this sector has adequate representation in decisions affecting DER interconnection.

1.2 Electric Generation

To meet customer demand, PREPA's 2019 IRP recommends a generation fleet that includes 5,336 MW[3] of generation capacity, with 4,050 MW owned by PREPA. Electric demand has declined from its historical system peak of 3,685 MW in Fiscal Year 2006 to 3,159 MW in FY 2017 and 3,060 MW in August 2017.

According to the latest IRP, Puerto Rico's existing customer-owned distributed solar installed capacity is 130 MW (Siemens 2019a)[4]. Distributed generation in Puerto Rico includes distributed generation connected to the PREPA distribution system and customer-owned distributed generation connected to the transmission system. Both categories primarily comprise rooftop solar. Distributed generation is modeled in PREPA's IRP as "lumped" generation in each of eight[5] PREPA zones, reflecting distribution distributed generation and transmission distributed generation separately for each zone.

1.3 Distribution System Infrastructure

Puerto Rico's distribution system includes 31,485 miles of distribution lines and 334 substations. PREPA's distribution system comprises roughly 1,200 circuits. PREPA's distribution system is primarily overhead, with 6% of the circuit miles located underground. Substations fed by 38-kV lines account for two-thirds of PREPA's distribution capacity on the island. Most of PREPA's assets were installed more than 30 years ago (Puerto Rico Energy Resiliency Working Group 2017, 9, 24, 25).

[2] For Fiscal Year 2019, petroleum fueled 40% of Puerto Rico's total electricity generation, and natural gas accounted for 39%. Coal continued to fuel 18% of generation, whereas renewables supplied 2.3% (EIA 2020a).

[3] This reflects PREPA's 2019 IRP. As input to the IRP, and based on discussions with PREPA, Siemens concluded that 39 existing units were in "acceptable operating condition" to be included in the IRP. The combined capacity of these units is 5,010 MW. Note that h in footnote 16 indicates the *nominal* capacity to be 5,213 MW (Siemens 2019b).

[4] As of April 2020, there are approximately 216 MW (transmission and distribution interconnected DG systems). (personal communications, Tomas Velez, PREPA, May 2020).

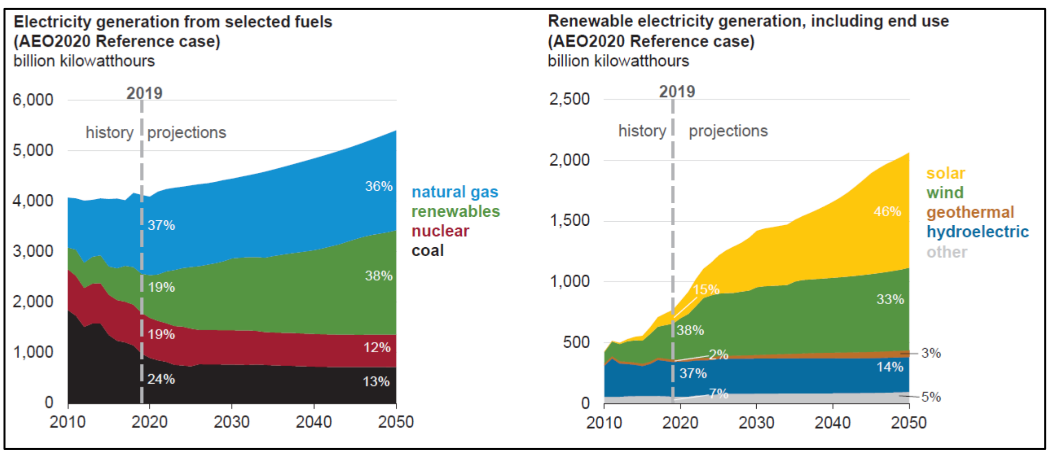
[5] In these tables from the IRP, PREPA divides the Ponce region into east and west: Ponce ES and Ponce OE; generally, this division is not noted when PREPA's regions are discussed.

2 Potential Changes and Technical Benefits at Higher DER Penetration Levels

The interconnection of DERs in Puerto Rico has evolved, especially since the increased implementation of solar energy systems. The changes in interconnection fall under both changes to interconnection processes and changes to interconnection technical requirements. In addition, major changes have taken place in the regulatory and policy arenas that affect DER interconnection.

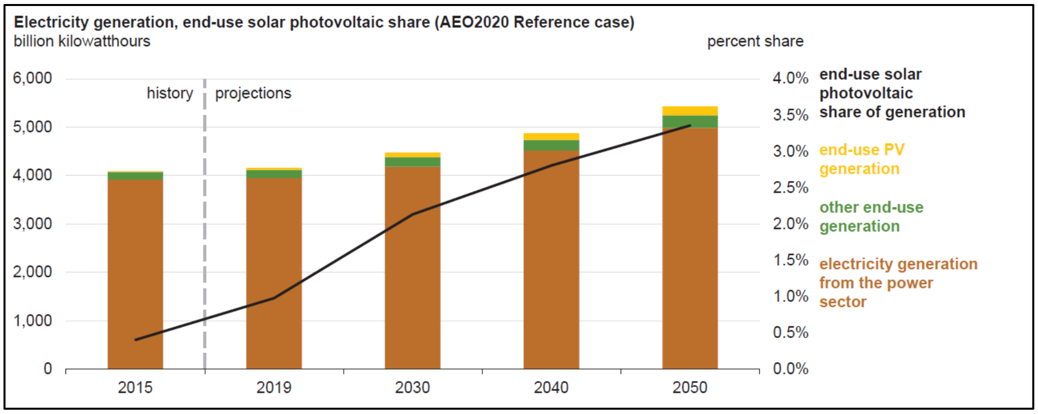
2.1 Changing Landscape for Renewables and Distributed Energy Resources

It is clear that the future EPS across the United States will contain more renewable energy systems. The EIA forecasts that the share of electricity generation from renewable sources will double by 2050, with 46% of that growth coming from solar energy, as shown in Figure 5 (EIA 2020b). The EIA projects that distributed generation will also increase, as shown in Figure 6.



Source: EIA 2020b

Figure 5. EIA generation projections



Source: EIA 2020

Figure 6. EIA projection: increasing distributed generation

Puerto Rico has had renewable energy targets for the past decade. Act No. 82 in July 19, 2010, created an RPS (P.R. Law 82). This law required load-serving entities to supply increasing shares of retail sales with qualified renewable and alternative sources starting at 12% in 2015, increasing to 15% in 2027, and 20% in 2035. Puerto Rico's renewable targets adopted in Act 17-2019 mandate 100% renewables by 2050.

The IRP filed by PREPA in 2019 contains a forecast in the growth of distributed PV. The 2019 IRP analyzes several future generation portfolios. The one depicted in Figure 7 and Figure 8 is *Scenario 4, Strategy 2, Baseload*.

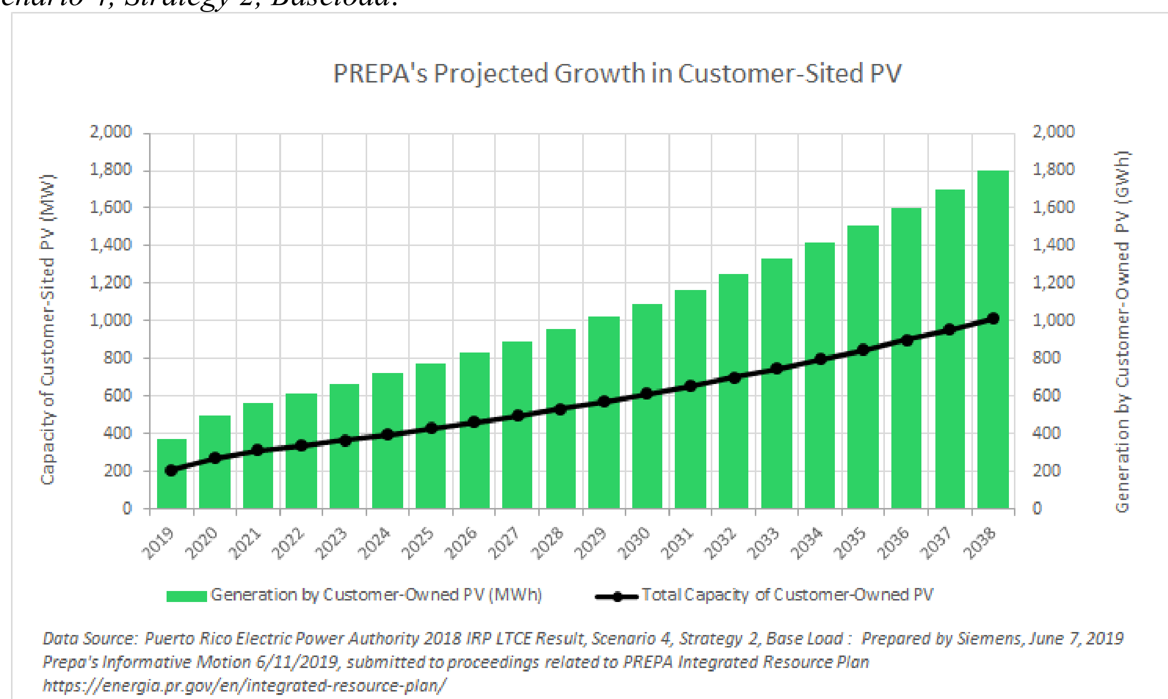


Figure 7. PREPA's projected growth of distributed PV

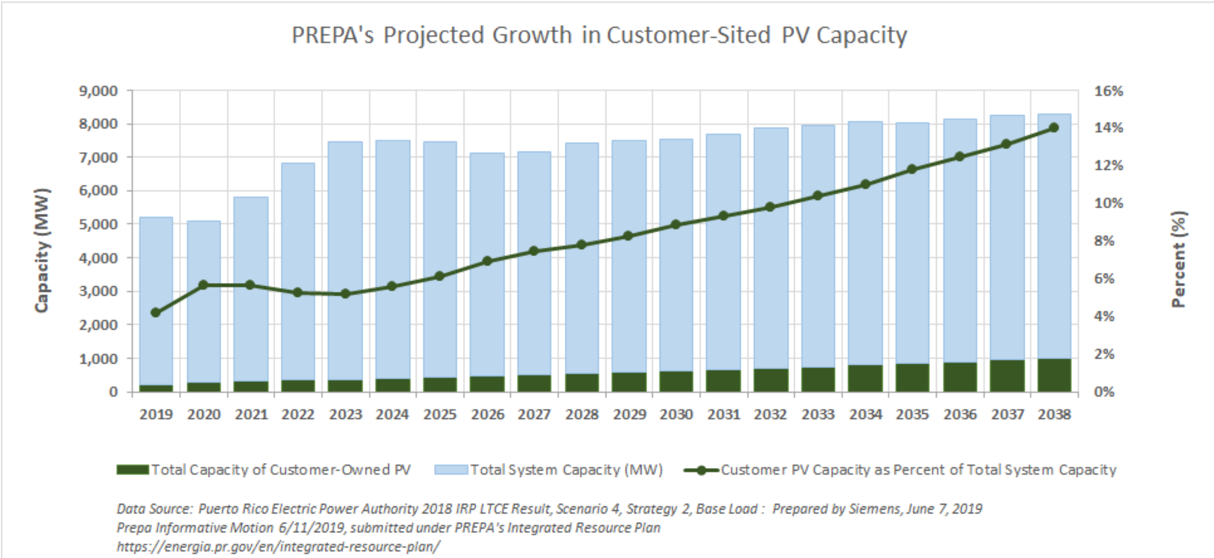
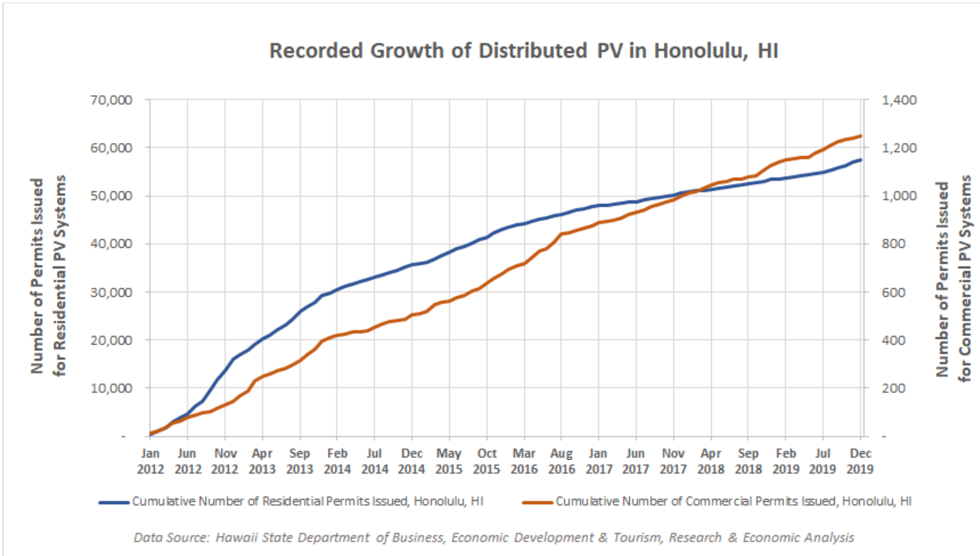


Figure 8. PREPA's Projected Growth in Customer-Sited PV Capacity

2.2 Further Considerations: Distributed Energy Resources as Part of an Overall Grid Modernization Strategy

Given the Act 17-2019 requirement to get to 100% renewables by 2050, it is expected that the trend for DERs will continue or increase. Note that experience from other regions suggests that energy policy and market conditions can have large impacts on the amount of DER installed capacity. Increases in DER can happen more quickly, relative to the traditional planning process of most electric utilities. For example, consider the growth of distributed PV in Hawaii. Figure 9 illustrates the growth in residential and commercial PV in Honolulu, Hawaii, from 2012 through 2019. Figure 9 shows the cumulative installed capacity of residential and commercial distributed PV systems in the Hawaiian Electric Companies service areas, which provide electricity for approximately 95% of Hawaii's population.



Source: State of Hawaii 2020

Figure 9. Growth of distributed PV in Honolulu, HI

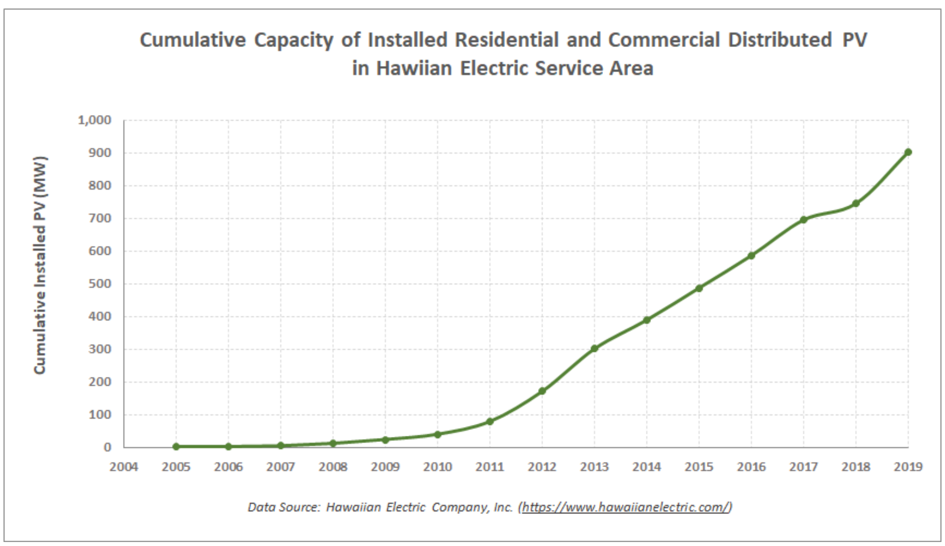


Figure 10. Cumulative capacity of residential and commercial PV in the Hawaiian Electric Companies' service areas

Ultimately, Hawaii recognized DERs as an integral part of not only the island's energy mix but also an interrelated part of Hawaii's grid modernization strategy. This is evidenced by Hawaiian Electric Companies' Power Supply Improvement Plan (PSIP)[6] of December 23, 2017, in which HECO described strategies for grid modernization, including improvements to grid infrastructure to increase DER hosting capacity. These strategies were considered near-term activities as part of the overall Grid Modernization Action Plan. The strategies included:

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[6] See Hawaiian Electric Companies' PSIPs Update Report: Book 1 or 4—Docket No. 2014-0183, https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A16L27B50409B58212.

- Activation of new advanced inverter functions based on the first phase of analysis and testing of seven high-priority advanced inverter functions deemed necessary to support the integration of DERs into Hawaii's electric grid. This recommendation was based on work in partnership with NREL[7] that showed results of performance testing several models of advanced inverters. The results were used to develop a common set of technical requirements ("Source Requirements Document") that would enable manufacturers to certify their equipment under the Underwriters Laboratory (UL) 1741 Supplement A test standards as required by Hawaii's Rule 14H Interconnection Rule.
- Updates to operational strategies to mitigate primary and secondary impacts of DER integration to increase distribution circuity hosting capacities, supported by a new round of study and analysis of the technical issues
- Development of methods to use inverter-based DERs for frequency support. This effort was supported by projects under the DOE Grid Modernization Laboratory Consortium, with participation from multiple DOE laboratories, including NREL and Sandia National Laboratories, as well as inverter manufacturers.
- Development of requirements for DER communications, monitoring, and reporting to improve situational awareness and to improve configurability and control of DER assets.
- Evaluation of voltage-reactive power (volt-volt ampere reactive [VAR]) optimization to improve distribution circuit hosting capacity. This included evaluation of other grid-interactive devices, such as Varentec's ENGO and GEMS products for reactive power compensation and Gridco's In-line Power Regulator (IPR) devices to provide real-time voltage regulation and monitoring.
- Traditional strategies for improving DER hosting capacities included upgrades and optimized settings for load tap changers, installations of voltage regulators, upgrades to distribution transformers, and conversion of secondary conductors from 4 kV to higher levels.
- Addition of fast frequency response contingency resources including demand response programs and supplemental fast frequency response reserve storage systems
- Addition of synchronous condensers to provide reactive power for voltage support and short-circuit capacity needed for correct operation of protective relaying schemes
- Additional research-and-development activities and pilot projects to improve voltage and frequency management, to improve situational awareness and visualization, and to improve overall DER integration.

In some states, the wish to encourage distributed energy, a "DG carve-out" or a credit multiplier is embedded into regulatory policy. The carve-out satisfies part of a larger RPS, and it requires a percentage of the overall renewable requirement to be furnished by a specific type of technology or technology application. A credit multiplier is another way to encourage (or discourage) a specific technology or application, and it can be set up to award more than one renewable energy certificate as an incentive for a specific technology or less than one Renewable Energy Certificate as a disincentive (Lips 2018).[8]

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[7] See *Hawaiian Electric Advanced Inverter Grid Support Function Laboratory Validation and Analysis* by Austin Nelson et al., https://www.nrel.gov/docs/fy17osti/67485.pdf.
[8] For a comparison of multipliers and carve-outs, see Lips (2018).

For example, the RPS in Arizona, the Renewable Energy Standard and Tariff mandates that regulated utilities must obtain renewable energy credits from distributed renewable energy resources for a percentage of the total renewable energy requirement (Arizona Corporation Commission 2006). The amount increased in 5% increments from 2007 through 2011, with a final goal of 30%. Arizona's RPS also contains several multipliers, such as a .5 multiplier for a distributed solar electric generator (Arizona Corporation Commission 2006). Across the United States, 22 states have similar types of provisions for requiring solar or distributed generation (Database of State Incentives for Renewables & Efficiency 2017).

Puerto Rico stakeholders might wish to review this construct to see whether it provides support for Puerto Rico's overall energy goals.

Analyses have shown that the value of solar decreases with increasing penetration (Mills and Wiser 2013), and a framework is needed in Puerto Rico to estimate the effective cost of resilience at increasing penetrations of solar. For example, suppose PREPA targets 50% solar energy and offers a feed-in-tariff (or net energy metering) of $0.25/kWh-solar. At 50% penetration, the avoided cost of solar could be only $0.10/kWh, resulting in a resilience premium of $0.15/kWh. A framework will help decision makers determine how much solar and energy storage is right for Puerto Rico. It could also provide the following:

- Context in the form of value-of-lost-load studies
- Context in the form of solar/battery costs and what feed-in-tariffs are necessary to encourage community leaders to install solar and battery costs
- Estimate of how resilience premiums could affect the average all-in rate for Puerto Rico (An all-in rate is the total revenue requirement divided by the total sales and is an average rate for all customers in $/kWh.)
- A framework for estimating the optimal mix of renewable energy should be provided by DERs and how much should be connected to the bulk grid.

Other jurisdictions have found it beneficial to conduct research and field pilot studies to gain firsthand knowledge and experience with regard to new DER capabilities, especially PV and energy storage. Puerto Rico stakeholders might find such activities informative. At the state level, many of these activities are developed and funded by a team dedicated to research-and-development activities to support energy policy. Examples of these are New York State Energy Research and Development Authority[9] and the California Energy Commission.[10] In Puerto Rico, this activity could be carried out by the DDEC.

[9] See https://www.nyserda.ny.gov/.
[10] See https://www.energy.ca.gov/.

3 Potential Updates to Technical Requirements

At the time that the current PREPA distributed generation regulations were adopted, advanced inverter options were not available, and IEEE Std 1547-2018 was not yet approved.

3.1 Reactive Power Capabilities

Modern PV and battery energy storage system inverters with reactive power capabilities can help manage overvoltage problems, which are commonly stated as a concern on distribution circuits with high penetrations of DERs. Inverters with a lagging power factor setting (i.e., absorbing reactive power) can mitigate noncompliant voltage rise and increase circuit hosting capacity.

PREPA does not specify reactive power capability requirements for distributed generators (PV or otherwise); however, these capabilities might be beneficial given the expected increase in DERs. PREPA's interconnection requirements should be reviewed to determine if these capabilities should be enabled and applied under the IEEE Std 1547 guidelines. Note that per the revised IEEE Std 1547, these capabilities are required for all DERs, and therefore the benefits can be realized without additional capital cost.

Table 1 compares the active voltage regulation requirements in IEEE Std 1547-2018 and in various jurisdictional rules, including PREPA.

Table 1. Active Voltage Regulation Requirements in IEEE Std 1547-2018 and Various Jurisdictions

DER Performance Categories for Normal Grid Conditions	IEEE Std 1547 Category A DER[a]	IEEE Std 1547 Category B DER[b]	PREPA[c]	Hawaii Rule 14[d]	Arizona Public Service[e]
Voltage regulation	Mandatory capability	Mandatory capability	Not permitted	Mandatory for inverter-based	Mandatory for inverter-based
Constant power factor mode	Required	Required	Not permitted	Required (deactivated)	Required
Constant reactive power mode ("reactive power priority")	Required	Required	Not permitted	Required	Required
Voltage-reactive power mode ("volt-VAR")	Required	Required	Not permitted	Required (activated)	Required
Active power-reactive power mode ("watt-VAR")	Not required	Required	Not permitted	Not required	Not required
Voltage-active power mode ("volt-watt")	Not required	Required	Not permitted	Required (activated by mutual consent)	Required

[a] Meets minimum performance capabilities needed for area EPS voltage regulation. Reasonably attainable by all state-of-the-art DER technologies

[b] Meets all requirements in Category A plus supplemental capabilities for high DER penetration, where the DER power output is subject to frequent large variations. Attainable by most smart inverters

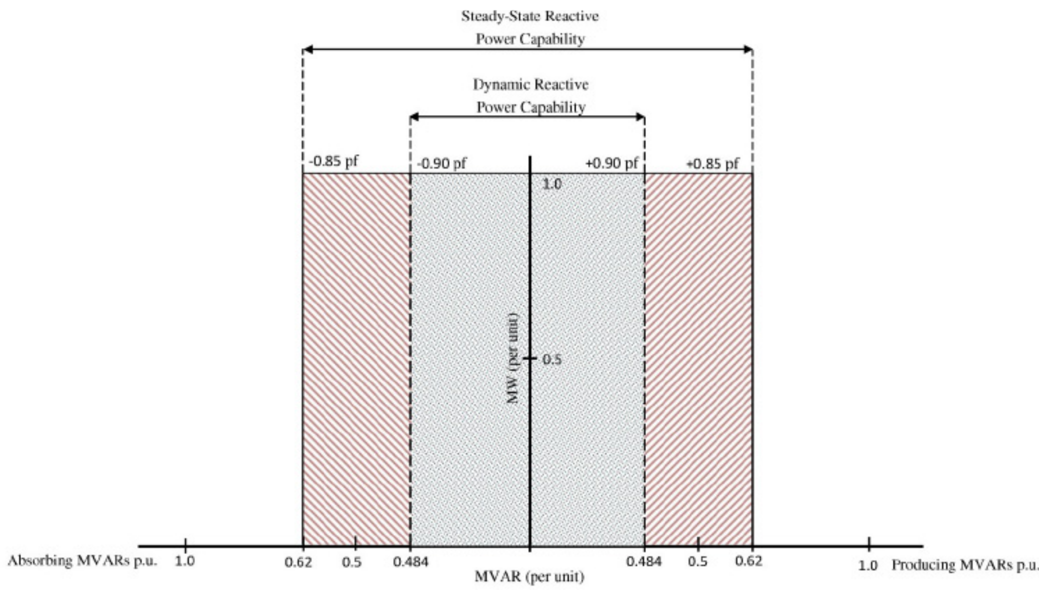
[c] Source: PREPA 2017

[d] Source: Hawaiian Electric 2020

[e] Source: Arizona Public Service Company 2019

3.1.1 Further Considerations

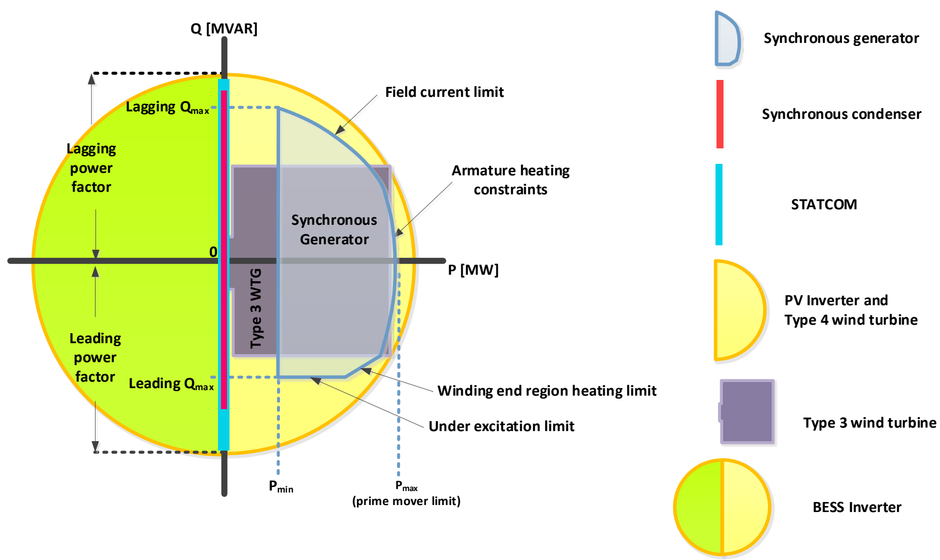
In Phase 1 of the multilab effort, NREL made recommendations for updating the minimum technical requirements for large-scale generators connected to PREPA's transmission system. This report noted that many modern PV and battery energy storage system inverters meet or exceed PREPA's current reactive power requirements shown in Figure 11 (Gevorgian and Baggu, n.d.).



Source: Gevorgian and Baggu n.d.

Figure 11. PREPA's reactive power requirements for large-scale generators

A diagram of reactive power capabilities of modern PV and battery energy storage system inverters compared to other devices with reactive power devices capabilities is shown in Figure 12.



Source: Gevorgian and Baggu n.d.

Figure 12. Reactive power capabilities among various devices

3.2 Response to Abnormal Voltage and Frequency

At lower penetration levels, the impact of DERs might not be significant on the bulk power system or transmission-distribution interface. As the DER penetration increases, however, issues related to transmission line loading, grid voltage, and system frequency during normal and disturbed operations might be a concern at the bulk system level; hence, suitable care must be taken to ensure that the impact is addressed appropriately in planning and operating assessments.

Regulators need to ensure that a collaborative effort is made with the utility (including transmission operation) and DER experts to identify the risks to the bulk power system, model them appropriately, and take suitable measures to mitigate them.

With the advent of high penetrations of DERs, the North American Electric Reliability Corporation prescribes that transmission planners and planning coordinators, in conjunction with their distribution planning/engineering team, should identify thresholds where DERs should be accounted in the power flow and dynamics cases. The thresholds should be based on either the individual or aggregate impact of DERs on the bulk power system.

PREPA's IRP, in support of the commonwealth's policy goals, anticipates more than 1,000 MW of distributed generation by 2038. PREPA's interconnection requirements specify that all generators greater than 1 MW be connected to the transmission or subtransmission system. Additional studies should be done to evaluate the benefits of connecting systems at the distribution level from 1 MW to 5 MW with DER voltage regulation enabled. Residential customers may install systems in size up to a maximum of 25 kW. DERs are expected to comply with IEEE Std 1547.

PREPA specifies that DER sized 500 kW or more must comply with abnormal voltage and frequency trip requirements. These values are to be programed into the DER or protective equipment. For reference, the voltage trip requirements are recreated here in Table 3, and the frequency trip requirements are recreated here in Table 4.[11]

At the DER level, PREPA does not specify any requirements for ride-through of abnormal voltage. PREPA should reconsider this considering the revised IEEE Std 1547 and best practices from other jurisdictions for managing the increase in distributed generation. Table 2 provides a comparison of ride-through requirements in IEEE Std 1547 to various jurisdictional rules, including PREPA.

[11] When this regulation was being amended (Regulation 8915), the values in the tables were decided considering IEEE Std 1547a-2014 (personal communications, Tomas Velez, PREPA, May 2020).

Table 2. Comparison of Ride-Through Requirements

DER Performance Categories for Abnormal Grid Conditions	IEEE Std 1547 Category I DER[a]	IEEE Std 1547 Category II DER[b]	IEEE Std 1547 Category III DER[c]	PREPA[d]	Hawaii Rule 14[e]	Arizona Public Service[f]
Ride-through of abnormal voltage and frequency	Mandatory capability	Mandatory capability	Mandatory capability	Not permitted	Mandatory for inverter-based	Mandatory for inverter-based
Voltage ride-through	Required	Required	Required	Not permitted	Required (activated)	Required
Frequency ride-through	Required	Required	Required	Not permitted	Required (activated)	Required
Rate-of-change-of-frequency (ROCOF) ride-through	Required (0.5 Hz/s)	Required (2.0 Hz/s)	Required (3.0 Hz/s)	Not permitted	Not required	Not required
Voltage phase angle change ride-through	Required	Required	Required	Not permitted	Not required	Not required
Frequency droop (frequency-power)	Optional for low frequency	Required	Required	Not permitted	Required (activated)	Required
Inertial response	Permitted	Permitted	Permitted	Not permitted	Not required	Not required
Dynamic voltage support	Permitted	Permitted	Permitted	Not permitted	Not required	Not required

[a] Meets essential bulk system needs, attainable by all state-of-the-art DER technologies

[b] Allows full coordination with all bulk system power system stability/ reliability needs (e.g., North American Electric Reliability Corporation). Coordinated with existing reliability standards to avoid tripping for a wider range of disturbances (than Category I)

[c] Designed for all bulk system needs and distribution system reliability/power quality needs. Coordinated with existing requirements for very high DER levels (e.g., California, Hawaii)

[d] Source: PREPA 2017

[e] Source: Hawaiian Electric 2020

[f] Source: Arizona Public Service Company 2019

3.2.1 Abnormal Voltage Trip Requirements

PREPA specifies DER must-trip requirements (disconnection times) for overvoltage (OV) and undervoltage (UV). A comparison of DER voltage trip requirements between PREPA and IEEE Std 1547-2018 is shown in Table 3.

PREPA's requirements are within the allowable ranges specified in IEEE Std 1547-2018 and follow settings for Category I DERs except for UV2, which allows a clearing time range that goes beyond Category I and Category II.

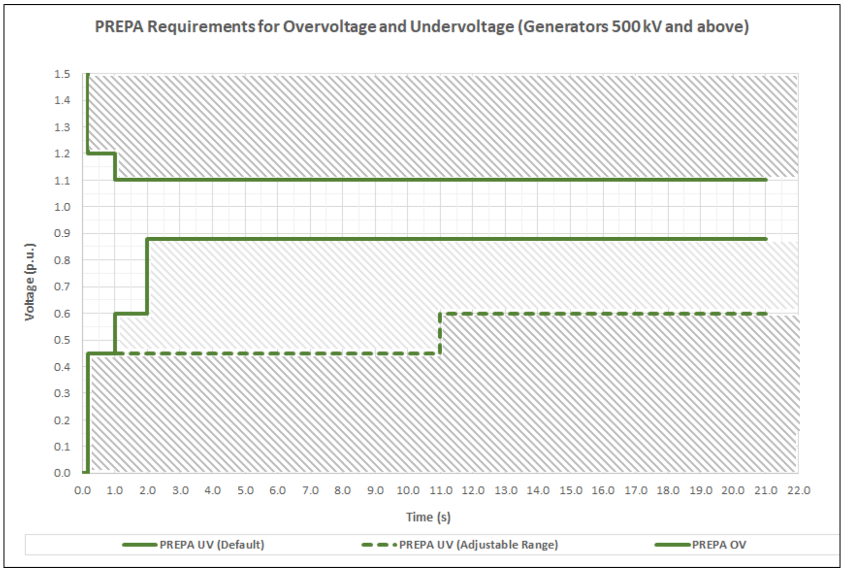
Table 3. Voltage Trip Settings Comparison between PREPA and IEEE Std 1547-2018

IEEE Std 1547-2018 Shall Trip Function	PREPA Requirements (>500 kW)		Category I DERs		Category II DERs		Category III DERs	
	Default and allowable range		Default and allowable range		Default and allowable range		Default and allowable range	
	Voltage (p.u. of nominal)	Clearing time (s)	Voltage (p.u. of nominal)	Clearing time (s)	Voltage (p.u. of nominal)	Clearing time (s)	Voltage (p.u. of nominal)	Clearing time (s)
OV2	V ≥ 1.20	0.16 (not adjustable)	1.20 (not adjustable)	0.16 (not adjustable)	Same as Category I		Same as Category I	
OV1	1.10 < V < 1.20	1 (1–13)	1.10 (1.10–1.20)	2.0 (1.0–13.0)	Same as Category I		Same as Category I	**13.0** (Same as Category I)
UV1	.60 ≤ V < .88	2 (2–21)	0.70 (0.0–0.88)	2.0 (2.0–21.0)	Same as Category I	**10.0** (Same as Category I)	**0.88** (0.0–0.88)	**21.0** (2.0–50.0)[a]
UV2	.45 ≤ V < .60	1 (1–11)	0.45 (0.0–0.50)	0.16 (0.16–2.0)	Same as Category I		**0.50** (0.0–0.50)	**2.0[a]** (0.16–21.0)[a]
	V < .45	0.16 (not adjustable)						

[a] The 2018 revision of IEEE Std 1547 specified ranges of allowable settings for clearing times for UV1 and UV2 of 21.0–50.0 and 2.0–21.0, respectively. In March 2020, an amendment to revise these settings was approved with the settings shown. See https://standards.ieee.org/standard/1547a-2020.html for details.

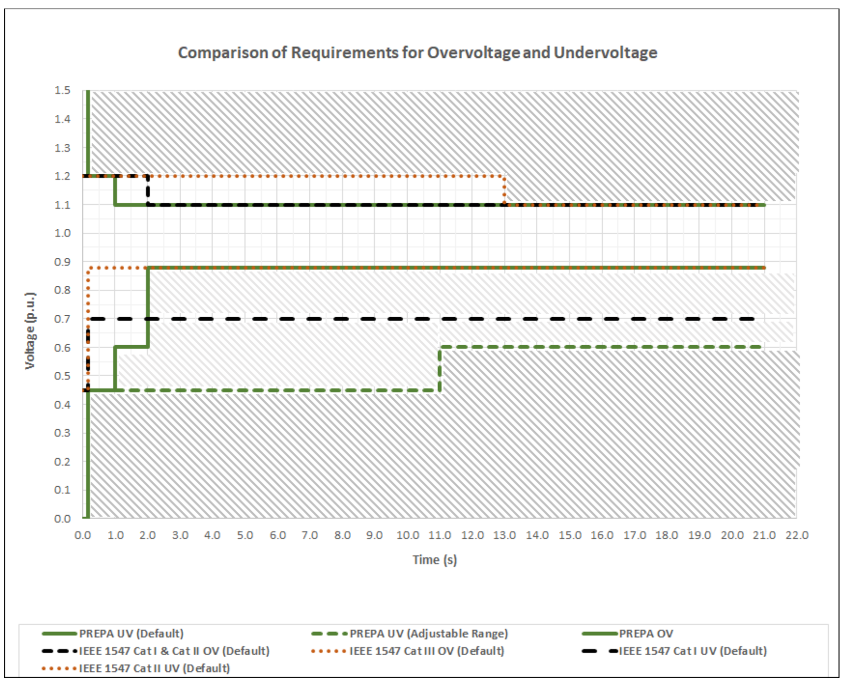
Sources: PREPA 2017, Table 3; IEEE 2018

A comparison of DER voltage trip requirements between PREPA and IEEE Std 1547-2018 is illustrated in Figure 12 and Figure 13.



Source: Based on PREPA 2017

Figure 13. PREPA requirements for overvoltage and undervoltage clearing times



Source: PREPA 2017; IEEE 2018

Figure 14. Comparison of trip requirements

3.2.2 Abnormal Voltage Ride-Through

PREPA does not specify requirements for ride-through of abnormal voltage at the distribution level; however, such requirements are specified for all generators connected to PREPA's transmission and subtransmission system. Similar ride-through requirements should be implemented for future DER interconnections following IEEE Std 1547-2018.

3.2.3 Abnormal Frequency Trip Requirements

PREPA specifies DER must-trip requirements (disconnection times) for overfrequency (OF) and underfrequency (UF). A comparison of DER frequency trip requirements between PREPA and IEEE Std 1547-2018 is shown in Table 4.

Table 4. Comparison of IEEE Std 1547 and PREPA Requirements for DER Response to Abnormal Frequency

Function	PREPA (>500 kW)		IEEE Std 1547 Default Settings (Ranges of Allowable Settings)	
	Frequency (Hz)	Disconnection Time (s)	Frequency (Hz)	Disconnection Time (s)
Low frequency 1 (UF2)	f < 57.5	10	56.5 (50.0–57.0)	0.16 (0.16–1000)
Low frequency 2 (UF1)	57.5 ≤ f < 59.2	300	58.5 (50.0–59.0)	300.0[a] (180.0–1000)
Over-frequency 1 (OF1)	60.5 < f ≤ 61.5	300	61.2 (61.0–66.0)	300.0 (180.0–1000)
Over-frequency 2 (OF2)	f > 61.5	10	62.0 (61.88–66.0)	0.16 (0.16–1000)

[a] Underfrequency disconnection time needs to be coordinated with underfrequency load-shedding programs and expected frequency restoration time.

Source: PREPA 2017; IEEE 2018

IEEE Std 1547-2018 specifies three categories of DER response to abnormal voltage and frequency conditions. These requirements apply to all DERs regardless of size.

3.2.4 Abnormal Frequency Ride-Through

PREPA does not specify requirements for ride-through of abnormal frequency at the distribution level; however, such requirements are specified for all generators connected to PREPA's transmission and subtransmission system. Similar ride-through requirements should be implemented for future DER interconnections following IEEE 1547-2018. A comparison of requirements between PREPA and IEEE Std 1547-2018 is shown in Figure 14.

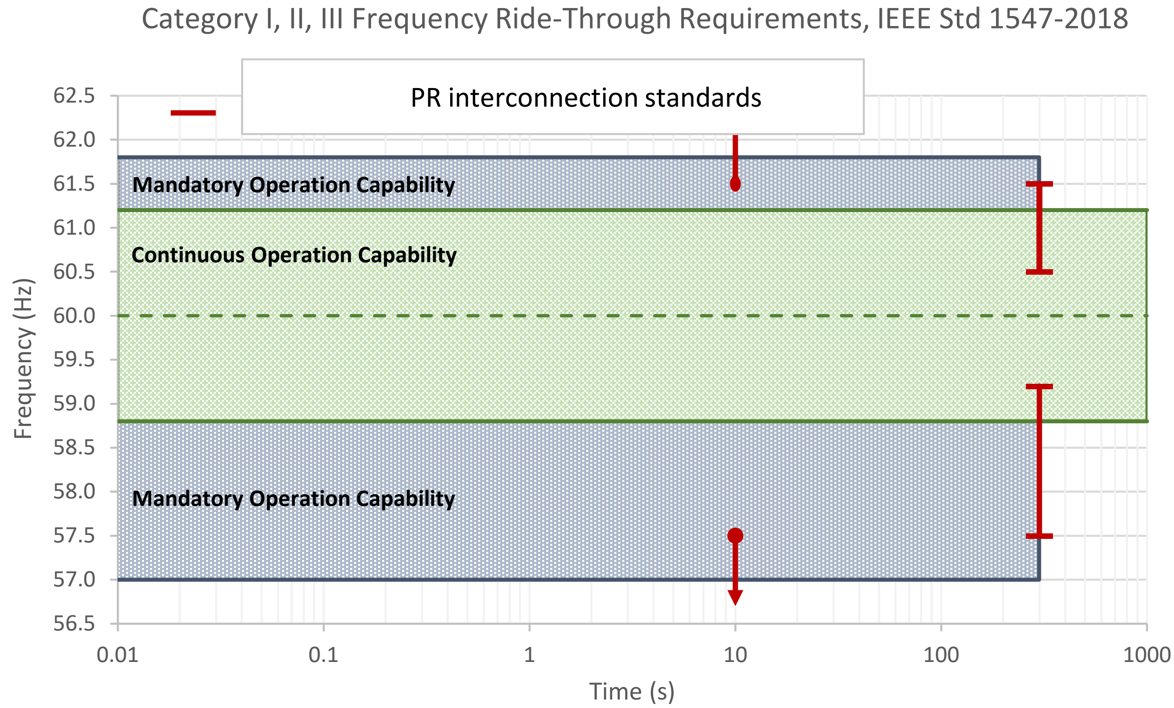
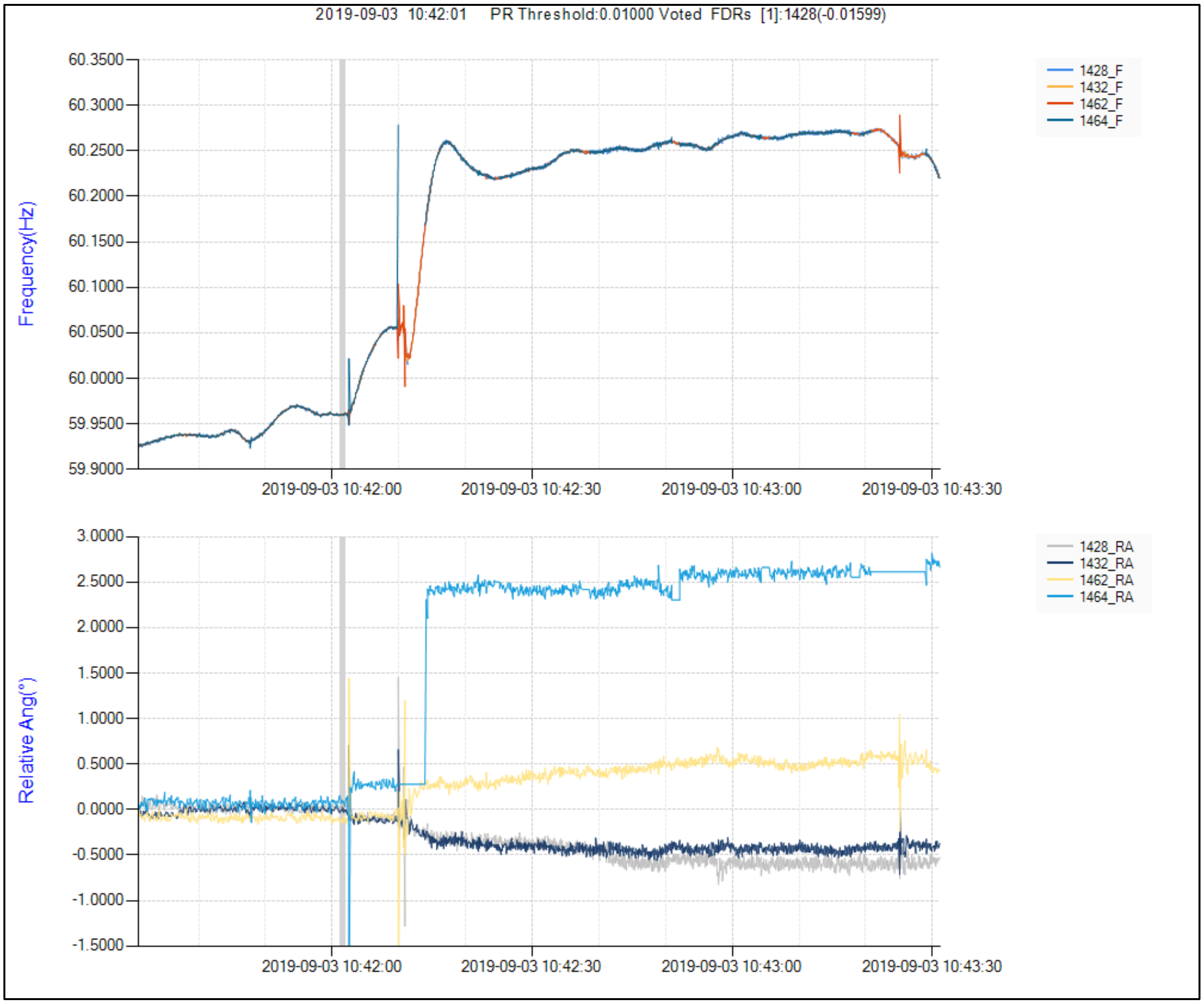


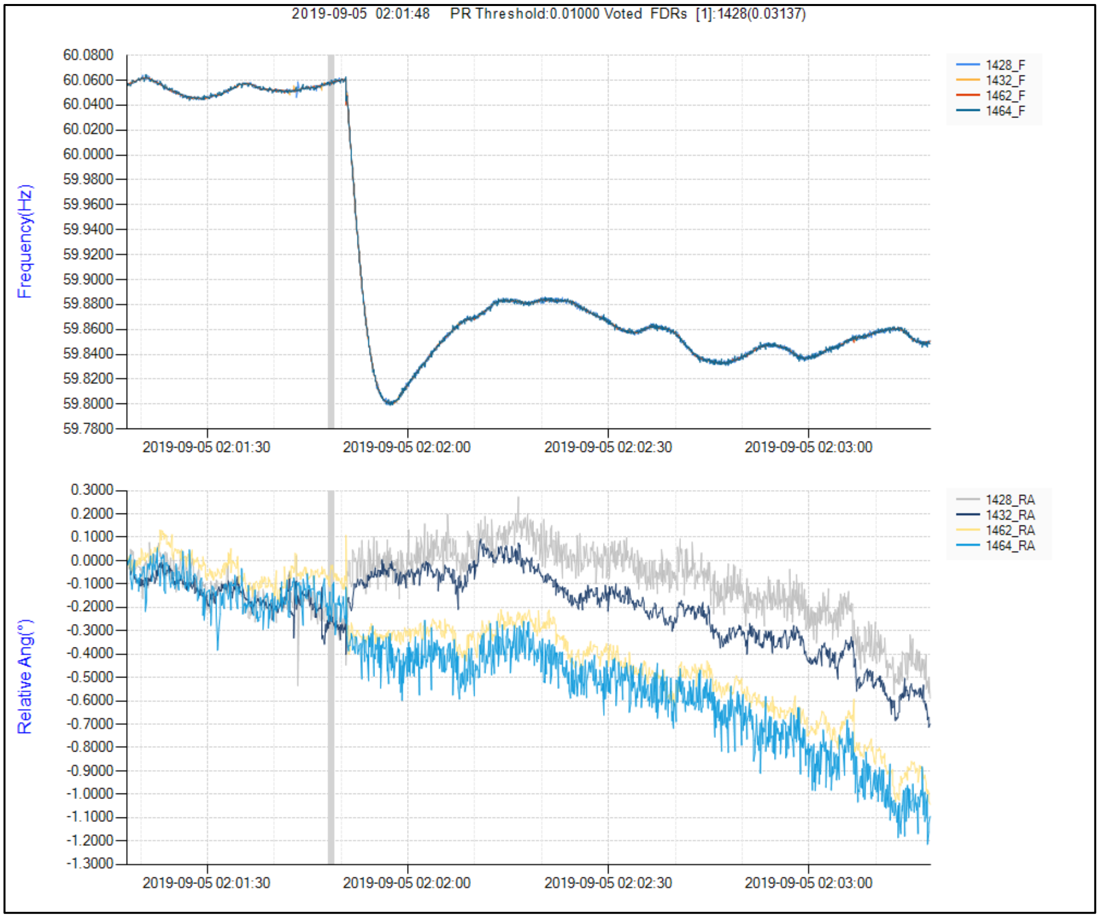
Figure 15. Comparison of frequency ride-through requirements

Under the DOE multilab project, the University of Tennessee installed frequency data recorders at various locations in Puerto Rico. Figure 15, Figure 16 and Figure 17 illustrate frequency disturbances at the distributed level.



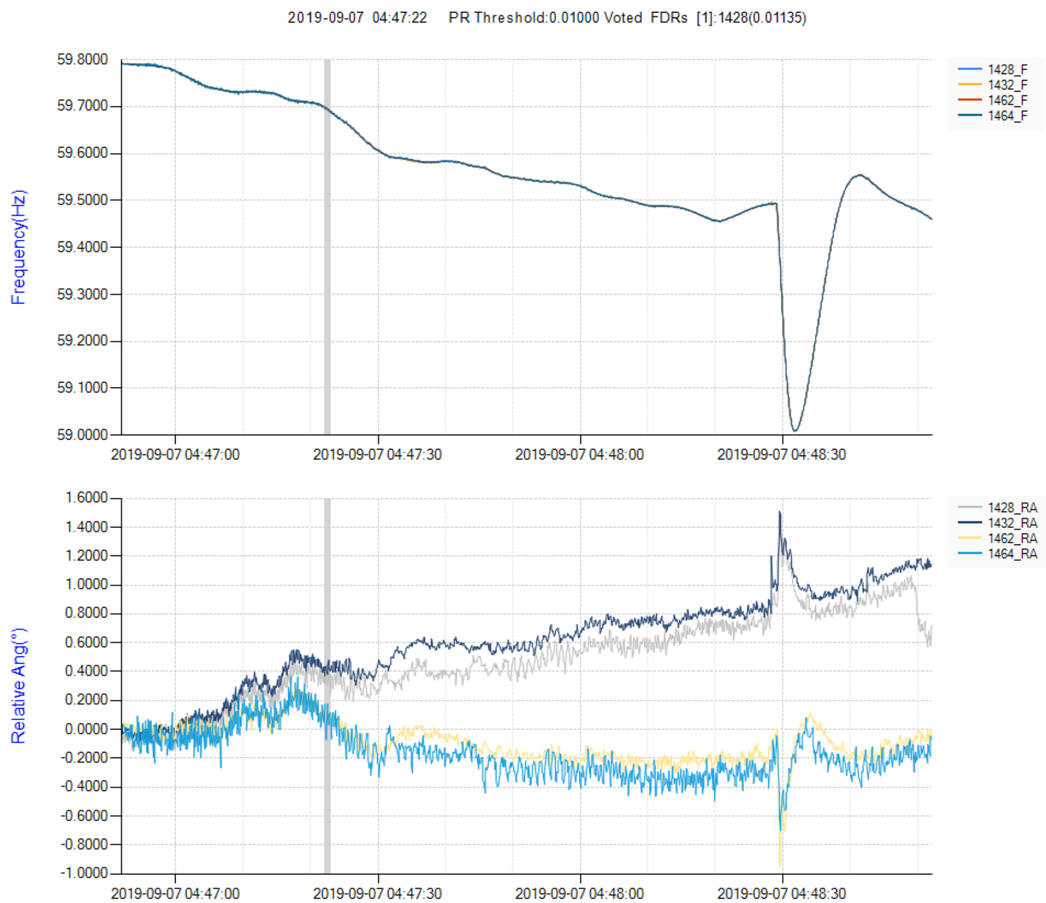
Source: Dr. Yilu Liu

Figure 16. Recorded data showing frequency disturbance (Example 1)



Source: Dr. Yilu Liu

Figure 17. Recorded data showing frequency disturbance (Example 2)



Source: Dr. Yilu Liu

Figure 18. Recorded data showing frequency disturbance (Example 3)

3.2.5 Further Considerations

- PREPA does not specify requirements for ride-through of abnormal frequency at the distribution level. This should be reviewed to determine whether requirements should be put in place, given the increase in distributed systems expected.
- Considerations for updating PREPA expedited process—updates to maximum distance of point of common coupling to feeder substation: Table 5 lists criteria for expedited review of systems between 200 kW and 1 MW. This might need to be reevaluated and revised given the expected increase in microgrids, as discussed.

Table 5. PREPA Feeder Length Criteria for DER Expedited Interconnections from 200 kW to 1 MW

Line-to-Line Voltage (KV)	Maximum Feeder Length from Substation to Point of Common Coupling
4.16	0.5
4.8	0.5
7.2	1.5
8.32	1.5
13.2	2.0

Source: PREPA 2017

3.3 Interoperability

A key addition to the overall implementation of the functional capabilities in IEEE Std 1547-2018 is interoperability (communications). Better interoperability will improve situational awareness, control capabilities, and customer participation. These features also allow the DER to have provisions for remote monitoring and control. Communications and information protocols were not addressed in the prior (2003) version of IEEE Std 1547 and were left for utilities and DER developers to negotiate based on system needs. This created challenges for the equipment suppliers, which traditionally used proprietary protocols in their equipment and had little guidance on required protocols, as well as for utilities that frequently use a combination of communications and information protocols.

IEEE Std 1547-2018 brings new requirements for communications protocols that must be available at the local DER communications interface. The standard sets required communications capabilities for the DERs at their interface with the area EPS communications network.

3.3.1 Further Consideration

- PREPA does not specify requirements for interoperability in its interconnection requirements. Requirements should be reviewed to determine whether new interoperability guidance is appropriate or required.
- Special note should be given to determining communications, monitoring, and control strategies for DERs in the context of grid services.
- Special note should be given to the types and scales of DERs that might require communications, monitoring, and control—for example, PV systems, battery-only or battery/PV, combined heat and power, microgrids, or minigrids. This should be evaluated under normal and abnormal conditions.
- In addition, special note should be given to long-term policy and market goals, such as customer participation, aggregation, community solar, and various stakeholders.
- Puerto Rico stakeholders might wish to review the *Common Smart Inverter Profile: IEEE 2030.5 Implementation Guide for Smart Inverters*[12] to determine whether it provides a suitable framework for interoperability considerations.

[12] See https://sunspec.org/wp-content/uploads/2018/03/CSIPImplementationGuidev2.003-02-2018-1.pdf.

3.4 Intentional Islands (Microgrids)

DOE defines a microgrid as "a group of interconnected loads and DERs within clearly defined electrical boundaries that act as a single controllable entity with respect to the grid" (Ton and Smith 2012). IEEE Std 1547-2018 uses the term *intentional island* to describe the same concept and defines an intentional island as a planned electrical island[13] that is capable of being energized by one or more local energy sources. Intentional islands have the capability to function both in grid-connected (parallel) mode and in islanded mode. Note that the terms *intentional island* and *microgrid* are often used interchangeably; however, specific standards might have varying definitions.

In Puerto Rico, use of intentional islands to improve local electric system resilience has been regulated at the distribution level via Regulation 9028 (PREB 2018). Using intentional islands for disaster recovery is being considered at the transmission level via the latest IRP from PREPA.

3.4.1 Microgrids at the Local Level

In May 2018, PREB published Regulation 9028, a set of rules intended to "promote and encourage the development of microgrid systems in Puerto Rico." The regulation is intended to be one of many long-term policies to help modernize the Puerto Rico electric system. In particular, this regulation encourages the development of local microgrids grouped into three classifications: (1) "Personal Microgrid," intended to serve the energy needs of a household; (2) "Cooperative Microgrid," intended to serve the needs of three or more cooperative members[14]; and (3) "Third-Party Microgrid," which is primarily developed to sell energy or other grid services to its customers or to PREPA.

IEEE Std 1547-2018 specifies technical requirements for intentional islands configured either as a facility island or an area EPS island. These configurations are illustrated in Figure 18.

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[13] "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"," (IEEE 2018).

[14] Regulation 9028 states that "For purposes of this Regulation, a Cooperative may, but need not be, organized or operated pursuant to Act 164-2009, as amended, known as the Puerto Rico General Corporations Act or Act 239-2004, as amended, known as the General Cooperative Associations Act" (PREPA 2018a). According to the regulation, a "Small Cooperative Microgrid" is one with a total generating capacity of 250 kW or less, and a "Large Cooperative Microgrid" is one with a total generating capacity of more than 250 kW.

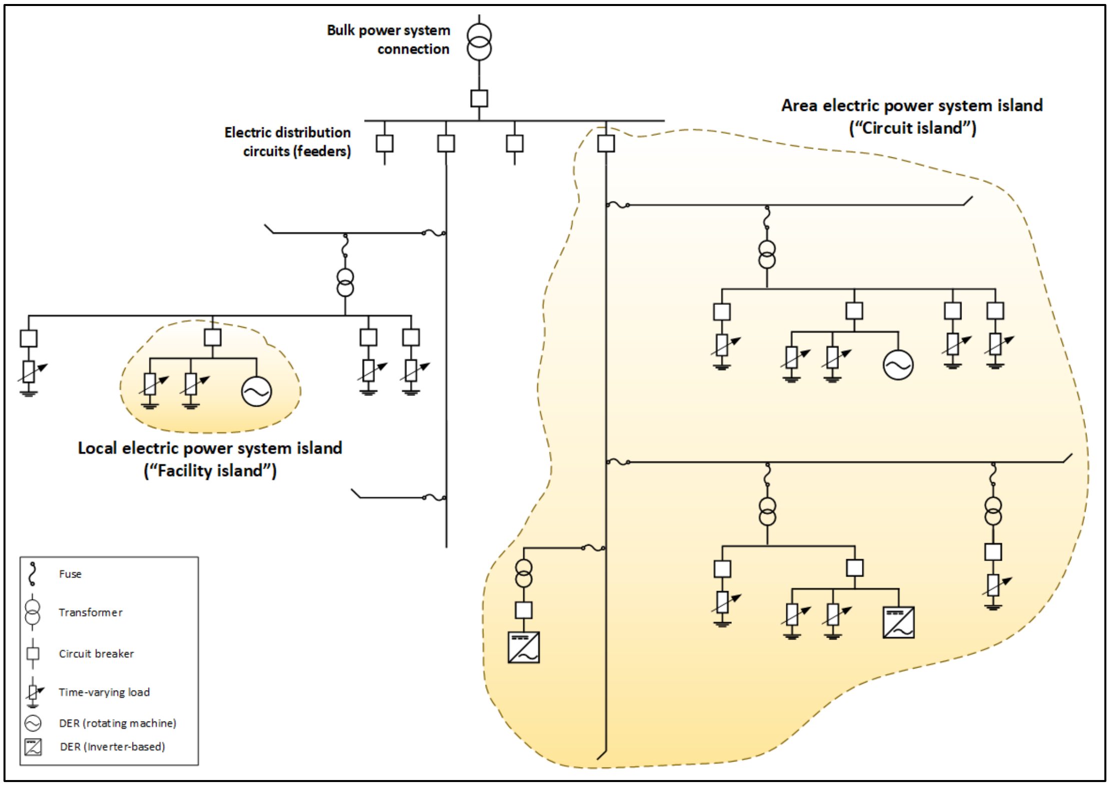


Figure 19. Two configurations of intentional islands

A "facility island" is typically installed to serve the needs of a single or a single set of customers. In such a case, the considerations for interconnection of the facility island are generally the same as for any other DER, with the addition of specific technical requirements for connection and disconnection from the electric system. The list of stakeholders in such an interaction are generally limited to the area EPS operator and the DER/intentional island operator and/or owner.

As pertains to Puerto Rico, the term *personal microgrid* is analogous to the term *facility island*.

In Regulation 9028, cooperative microgrids and third-party microgrids are intended to serve the needs of many customers; however, it is unclear whether such microgrids are expected to include portions of the area EPS owned by PREPA.

3.4.1.1 Microgrids in the 2019 Integrated Resource Plan

In addition to the minigrids discussed in the following, up to 48 smaller electrical islands (microgrids) are proposed. The proposed microgrids are centered around various substations located in areas PREPA has determined could take additional time to restore. The microgrids are planned to include roughly 236 MW of synchronous generation and 189 MW of combined PV and battery energy storage. Note that all generators proposed in the microgrids would be distributed generators. A summary of the microgrids, loads, and generation is shown in Table 6.

Table 6. Summary of Proposed Intentional Islands

Minigrid Region	No. of Proposed Micro-grids	Total Night Peak Load (MW)[a]	Minigrid Connected Load (MW)	Microgrid Connected Load (MW)	Proposed Microgrid Synchronous Generation (MW)	Planned and Proposed Microgrid PV+ Battery Energy Storage System (MW)
Arecibo	12	234.2	168.7	63.4	56	21.6
Caguas	6	306.7	271.7	40.7	36	8.1
Carolina	2	310.8	296.6	8.6	(Under request for proposal)	(Under request for proposal)
Cayey	5	101.1	59.9	41.2	41	20
Mayaguez North	2	163.5	139.2	32.8	23	10.2
Mayaguez South	9	161.7	140.2	22.2	18	6.9
Ponce	5	332.3	285.7	40.1	25	25.5
San Juan-Bayamon	7	1050.5	961.6	89.2	28	97.1
Totals[b]	48	2660.8	2322.6	338.2	235.6	189.4[c]

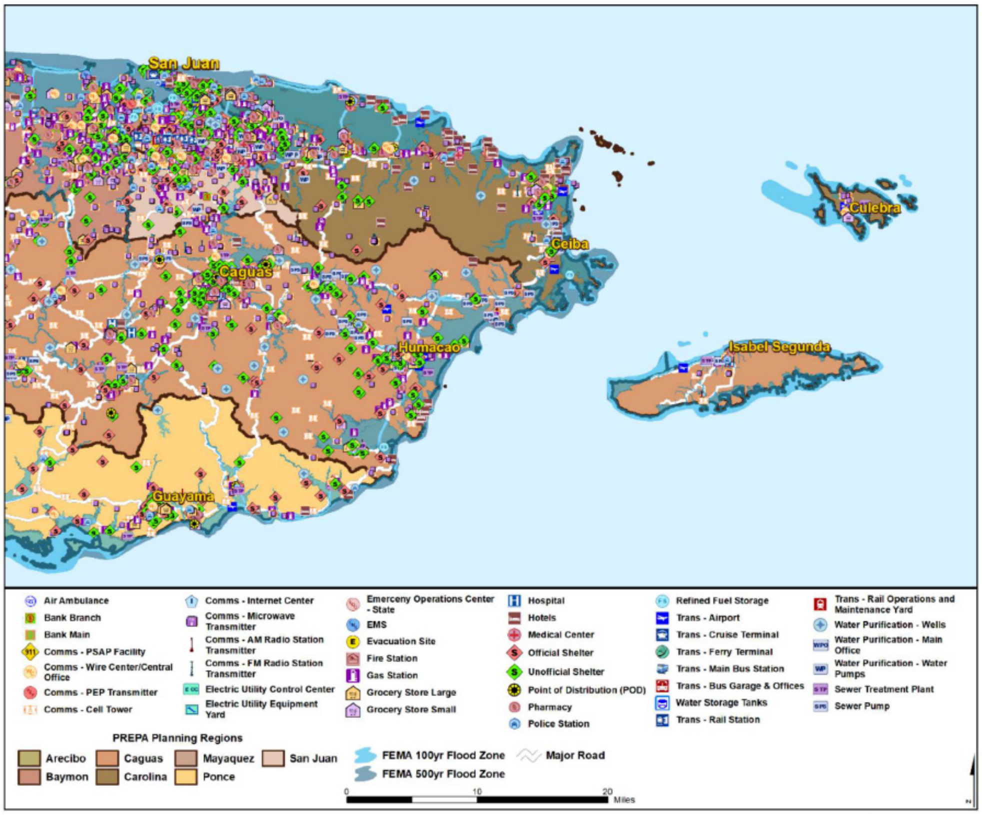
[a] Total load includes “Critical,” “Priority,” and “Balance of the Loads” as specified in PREPA (2019b). The IRP uses 2019 for loading conditions; however, it notes that this level is appropriate to plan for future years also.

[b] Note that differences in total might exist in this table from source tables. The referenced document itself differs between tables and text.

[c] This total includes 124.8 MW of planned PV + battery energy storage system and 64.6 of additional needed to supply “balance load” (Siemens 2019a, Exhibits 2-2, 2.4, 2.5).

3.4.1.2 Previous Research Findings

Sandia National Laboratories conducted research to determine improved resilience by using microgrids in Puerto Rico. Findings were published in September 2018. Using their Resilient Node Cluster Analysis Tool (ReNCAT) tool, Sandia mapped 6,643 individual infrastructure assets for their analysis. An example is shown in Figure 19.



Source: Jeffers et al. 2018

Figure 20. Sandia map of critical infrastructure in Eastern Puerto

Sandia's approach was to assign a number to the level of "community service" that certain types of institutions provided. Institutions that provided a higher, more important level of service received a higher numerical score (Jeffers et al. 2018). For example, to furnish the community service of communications, high-scoring institutions are cell towers, wire centers, and Internet service providers. Low-scoring infrastructure include microwave towers.

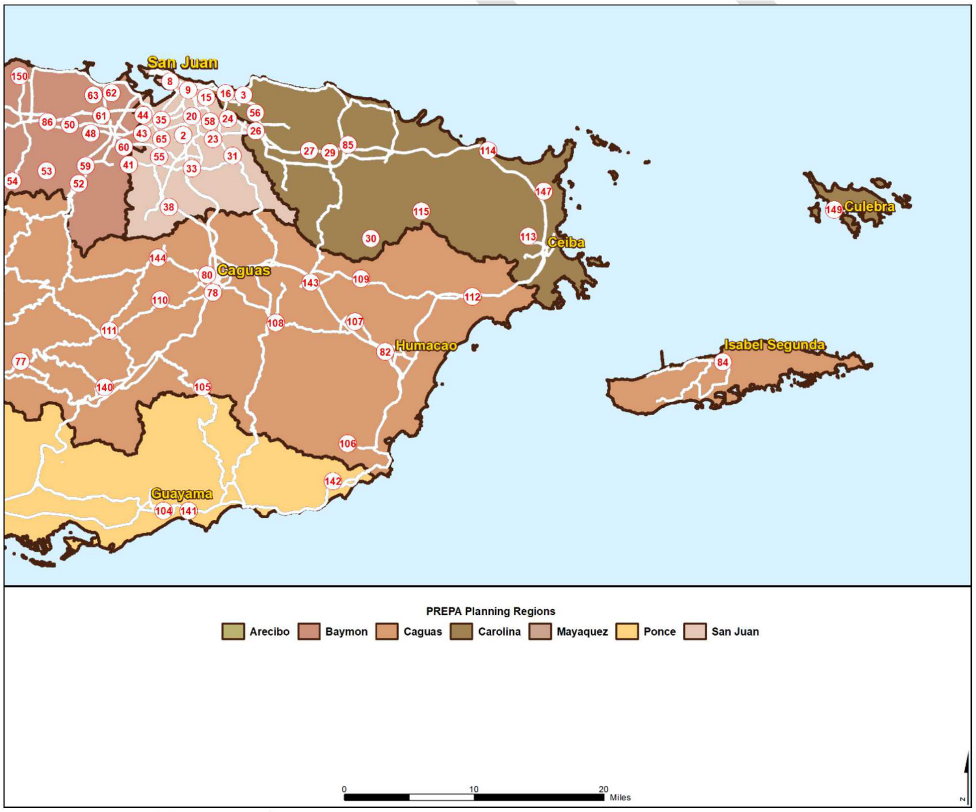
Table 7. Community Service and Infrastructure

Community Service	Highly Contributing Infrastructure Sector	Medium Contributing Infrastructure Sector
Communications	Cell towers, wire centers, Internet	
Emergency logistics	Local emergency operations center	AM radio station transmitters, FM radio station transmitters
Evacuation	Evacuation sites, airports	Wire centers, rail stations, bus main stations, cruise terminals
Finance	Bank mains	Bank branches
Food	Food points of distribution, large grocery stores, airports	Small grocery stores
Fuel	Gas stations, fuel storage	
Medical services	Hospitals, emergency medical services	Air ambulances, medical centers
Medications	Pharmacies	Hospitals
Restoration	Electric utility control center, electric utility equipment yard	Airports
Safety	Fire stations, public safety answering point	Emergency medical services
Security	Police stations, public safety answering point	
Shelter	Official shelters, hotels	Unofficial shelters
Transportation	Rail stations, bus main stations, airports	Rail operations and maintenance, bus garages, ferry terminals
Waste management	Sewer treatment plants	Sewer pumps
Water	Point of distribution, water main office and repair yard	Large grocery stores, water purification, water pumps, water storage tanks

Source: Jeffers et al. 2018

Sandia developed a resilience metric to determine the "burden on members of the community to satisfy their basic needs." This concept considers the effort needed to satisfy a community member's basic need (termed "community service" in Table 7) as well as the community member's ability to fulfill this need. Sandia compared this burden to a scenario with and without microgrids (Jeffers et al. 2018). Sandia also developed a "proxy metric" used to indicate the fraction of services that have power and can operate in islanded mode after a disruption.

Sandia noted that "Over small areas, for example 50 square miles, microgrids are highly effective at providing resilient infrastructure services to a population" (Jeffers et al. 2018). Sandia identified 159 locations with strong potential for microgrid application and calculated the potential cost to build these microgrids. Figure 20 shows an example for the eastern part of Puerto Rico (the numbered white circles represent microgrids).



Source: Jeffers et al. 2018

Figure 21. Sandia's map of potential microgrid locations in eastern Puerto Rico

The relative improvement to the decreasing burden with microgrids is shown in Figure 21, which illustrates that increased community resilience can be achieved with the use of microgrids.

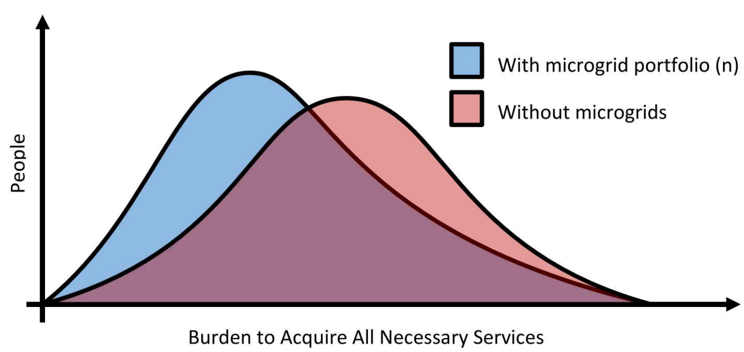


Figure 22. Sandia's community resilience metric with and without microgrids

3.4.2 Minigrids: Intentional Islands at the Transmission Level

The latest IRP from PREPA (Revision 2, submitted June 7, 2019) describes PREPA's proposal to invest in the ability to operate its grid in independently functioning sections, referred to as "minigrids" to improve the overall electrical system resilience. The design goal of the minigrids is to "ensure continued supply to critical loads (those loads most necessary for the safety and health) and provide timely recovery of the priority loads (those required to regain normalcy and restart the economy) and balance the loads within the MiniGrid" (PREPA 2019c). The IRP also recommends smaller microgrids for specific regions that might take longer to recover fully after a major disruptive event. To serve critical and priority loads in the minigrids, the IRP recommends adding 1,380 MW of PV, 920 MW of battery energy storage, and up to 414 MW of small (23-MW each) gas turbines.

An appendix to the IRP provides additional detail on the minigrid concept and defines that minigrids "are regions of the system that are interconnected with the rest of the EPS via transmission lines that could take more than a month to recover after a major event, and should be able to operate largely independently, with minimum disruption for the extended period of time that would take to recover full interconnection" (PREPA 2019b).

Minigrids proposed in the IRP correspond largely to PREPA's administrative regions, as shown in Figure 22.

Source data: Puerto Rico Government Open Data Portal n.d.; PREPA 2019

Figure 23. PREPA's minigrid concept proposed in 2019 IRP

PREPA describes the strategy for managing load in these minigrids in the IRP and breaks up the load into three classifications:

- **Critical loads:** Loads corresponding to facilities that provide key services needed during or immediately after an extreme event such as "hospitals, airports, seaports, police stations, fire stations, storm water pumps, critical water supply/treatment, AAA facilities, shelters /town centers and certain communication facilities"
- **Priority loads:** Loads needed to "restore normalcy," such as "shopping centers and commercial establishments, gas stations, industries, (and) higher density residential areas". Priority loads are expected to be fully restored within 10 days after an event.
- **Balance of the loads**: The remainder of the loads in the minigrid that are not critical or priority loads. Full restoration of these could take 10 or more days.

Minigrid-connected load totals 2323.6 MW (PREPA 2019b).

3.4.3 Further Considerations

In review of the work cited, this team notes the benefit of such analysis to improve the resilience of the infrastructure.

Puerto Rico Regulation 9028 also incentivizes microgrid development at a more granular level. The regulation is intended to improve resilience directly at the end-user level. To date, this aspect has not been fully studied; therefore, this team notes that additional benefit could be gained through a valuation of solar battery systems in rural Puerto Rico to quantify the cost, resilience benefits, and burden for customers trying to find basic services (shelter, lighting, communications) during natural disasters. These types of microgrids could be classified as personal, cooperative, or third-party microgrids under Regulation 9028. In addition, DERs in these microgrids could be based on individual or community solar projects. Further, although Regulation 9028 describes important policy and market rules associated with microgrids in Puerto Rico, technical requirements are lacking and should be addressed in the conventional interconnection rule and reflect functional capabilities included in IEEE Std 1547.

Leveraging the previous work from Sandia (i.e., ReNCAT) and the Pacific Northwest National Laboratory that identified microgrid locations for critical infrastructure, additional community center locations could be added that might serve only a few people per location but in mass could benefit more rural Puerto Ricans. A key benefit of this approach is that energy storage systems might be more accessible to rural Puerto Ricans and that overall many distributed independent energy storage systems might be more resilient than interconnected minigrids with exposed transmission and distribution infrastructure.

- To increase value, it could be assumed that many, if not most, of the microgrids will function in parallel mode most of the time. Puerto Rico stakeholders should consider communications and control strategies for the numerous systems. A common protocol and an application profile for the implementation of monitoring and control of DERs, including microgrids, might be beneficial. An example is the *Common Smart Inverter Profile*.
- To enable broader participation from individuals and to spur market engagement, Puerto Rico stakeholders should consider exploring a regulatory and technical framework for peer-to-peer energy exchanges. This could be of benefit under many grid conditions: normal, emergency, and recovery.

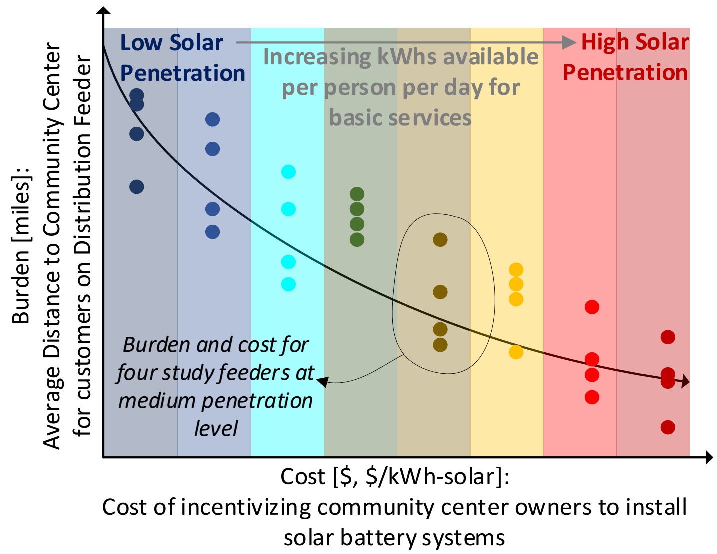


Figure 24. Notional example of decreased burden (travel distance) with solar/storage at individual level

To compare the cost of microgrids with the cost of distributed energy storage systems, the analysis could include a value-of-solar study that quantifies the avoided cost of solar at varying penetrations throughout the island. Because of the high cost of electricity on the island, incentives encouraging community center owners to provide shelter during natural disasters (e.g., a feed-in-tariff or net energy metering) will be relatively low. Energy storage systems will also not require additional distribution network infrastructure.

Additional analysis is needed to ensure that any proposed solar battery scenarios do not cause additional costs, such as reconductoring to mitigate voltage violations. These steps will include recommended placement of solar battery systems and low-cost smart inverter options to mitigate voltage violations.

Figure 24 is a notional graph of the anticipated results. It is a modification of work from Sandia from their report on the *Analysis of Microgrid Locations Benefitting Community Resilience for Puerto Rico*. The horizontal axis shows the cost associated with increasing penetrations of battery energy systems. The cost is found by calculating the difference between the avoided cost of energy storage systems and the incentive paid to customers to install solar battery systems. The vertical axis is the distance traveled (also referred to as the "burden") for Puerto Ricans to use the services at a community center. In this notional graph, returns diminish as cost increases because the value of solar decreases with higher penetrations. The shaded regions show the amount of solar associated with different costs. The analysis would quantify the kind of services available on average at the community center. For example, at low penetrations, only cell phone charging might be available. At higher penetrations, lighting, cooking, hot water, and entertainment might also be an option. Additional work is needed to refine this analysis—for example, a revision could include a study with incentives.

3.5 Summary of Recommendations for Updating DER Technical Requirements

As discussed, DER capabilities have improved, and in areas with high shares of DERs—especially PV or other inverter-based generation and storage—jurisdictions have found it prudent to review and revise technical requirements to take advantage of the new capabilities as enabled by the most recent IEEE Std 1547 interconnection standards. Key recommendations are summarized in Table 8.

Table 8. Summary of Recommendations for Updating DER Technical Standards

Category	Gap/Issue	Opportunity/Solution	Responsible Entity
Studies and pilots	Lack of firsthand knowledge and experience with inverter-based DER capabilities	Conduct studies and pilots designed to improve DER integration	PREB, PREPA, DDEC
DER value	Unclear value from DERs	Puerto Rico stakeholders might want to consider developing a framework for estimating the optimal mix of renewable energy that should be provided by DERs and how much should be connected to the bulk grid.	PREB, DDEC
DER interconnection	Need for updated technical requirements	PREPA does not specify the utilization of reactive power capability requirements for distributed generators (PV or otherwise); however, these capabilities could be beneficial given the expected increase in DERs. The interconnection requirements should be reviewed to determine if these capabilities should be enabled and to what extent.	PREB, PREPA
DER interconnection	Need for updated technical requirements	At the DER level, PREPA does not specify any requirements for ride-through of abnormal voltage. PREPA might want to reconsider this in light of the expected increase in distributed generation.	PREB, PREPA
DER interconnection	Need for updated technical requirements	PREPA does not specify requirements for interoperability in its interconnection requirements. Requirements should be reviewed to determine whether new interoperability guidance is appropriate or required.	PREB, PREPA
Microgrids	Need for additional study	Puerto Rico stakeholders might want to consider planning, coordination, communications, and control strategies for the numerous islanded systems expected.	PREB, PREPA, DDEC, Puerto Rico academic entities
Peer-to-peer energy exchange, microgrids	Need for additional study	Puerto Rico stakeholders should consider development of peer-to-peer energy mechanisms/markets, either for traditional DERs or as potential for opportunity/solution of enhanced incentive for microgrid development.	PREB, PREPA

4 Potential Revisions to Streamline the Interconnection Process

Law 133-2016 effectively strengthens the established law on interconnection and net metering (P.R. Law 133), as do Act 120-2018 (P.R. Law 120) and Act 17-2019, but at times they also inadvertently restrain flexibility. One example of this restraint is the reference in Law 133 to the Federal Energy Regulatory Commission Small Generator Interconnection Procedures (SGIP)/Small Generator Interconnection Agreement (SGIA), which are not up to date with state-of-the-art technology and current industry standards (e.g., IEEE Std 1547-2018) and might not reflect the challenges and opportunities in island grids. With respect to safety and reliability issues (such as voltage and frequency ride-through and anti-islanding protection), regulators should consider that the SGIP/SGIA were developed before most current solar facilities in the United States had been installed. Although these Federal Energy Regulatory Commission documents often serve as the basis for interconnection engineering screens and process, SGIP/SGIA do not specify the technical interconnection requirements.

Based on a preliminary analysis of the interconnection process, critical bottlenecks were identified in each phase and were discussed in detail with potential scope for review and revision.

The Puerto Rico interconnection process is codified by law (Act No. 57-2014) and is also stated by PREPA's interconnection regulation PREPA 8915 (PREPA 2017).

PREPA's interconnection process and technical requirements are implemented at both the central and regional level. In each of the seven regions, PREPA maintains a regional engineering department that is responsible for implementing the interconnection process (and enforcing the technical requirements). All interconnection requests that can follow the expedited process are managed at the regional level. Interconnection requests that are nonexpedited are referred to PREPA's Distribution System Planning and Research Department in San Juan.[15]

An English translation of PREPA's interconnection requirements could not be located. A full, professional translation was considered cost-prohibitive; therefore, the NREL team developed a translation first through electronic means, and then NREL personnel with Spanish-speaking skills reviewed and conducted an edit of the electronic copy. This is included in this report as Appendix A.

The high-level interconnection process is described in a flowchart published by PREPA. The NREL team also translated this flowchart into English. The flowchart is based on the 2007 version of the interconnection requirements, and a revised version corresponding to the latest regulations (February 6, 2017) could not be located. The NREL team therefore developed a revised flowchart based on the latest regulations. This is shown in Figure 24 and was shared with

[15] Described in the interconnection process and confirmed with the regional office in Mayaguez.[16] Personal communications, Tomas Velez, PREPA, May 2020.

stakeholders in Puerto Rico for review and comment. The revised flowchart is also attached as Appendix B.

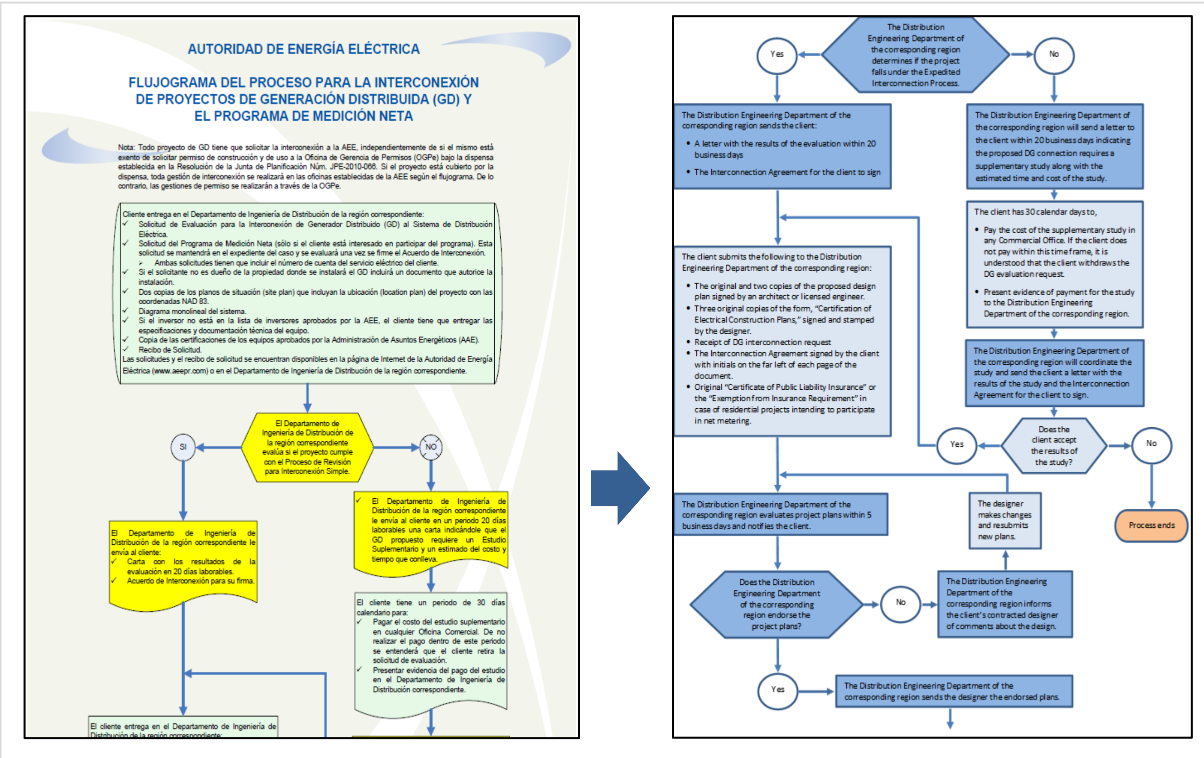


Figure 25. Interconnection process flowcharts

To facilitate analysis and discussion, an audit diagram technique was implemented for the numbering schema, and each process step was numbered for reference. At every decision block, steps with a positive decision outflow were numbered in whole numbers, whereas steps corresponding to a negative decision outflow were tracked through progressive levels of decimal digits. The audit diagram approach of numerical labeling as applied to the process flowchart diagram can actively be used to support performance management. This schema is particularly useful for performance managers and quality auditors in the identification and elimination of bottlenecks because it facilitates the identification of procedure steps that hold the largest in-process procedure queues (backlog).

4.1 Process Analysis for Distributed Energy Resource Interconnection

To visualize the interconnection process and identify critical bottlenecks, detailed process maps and activity flowcharts were developed by NREL. The primary objective of this task was to identify process steps that result in inefficiencies in the current process and that can be optimized or eliminated to augment increased penetration levels of DERs in Puerto Rico's electric grid. The entire process was subdivided into five major phases to facilitate phase-wise analysis of activities ranging from project inception through its termination, whereby the system interconnects with the grid at the identified point of interconnection. The latest copy of the PREPA interconnection procedure and a process flowchart summarizing a prior version of the PREPA interconnection process were used as the primary resources to develop the visualizations. The available flowchart was translated and updated to match a current version of the interconnection procedure. Figure 25 provides a brief overview of the major phases in the current interconnection procedure along with a high-level summary of the activities and process steps that constitute each phase. The figure references the flowchart developed for the interconnection process (Appendix B) and should be used as a supplement to the detailed flowchart. Activities in the process have been clustered into corresponding segments. Also included is a time estimate for each phase to distinguish between the expedited and standard interconnection procedures.

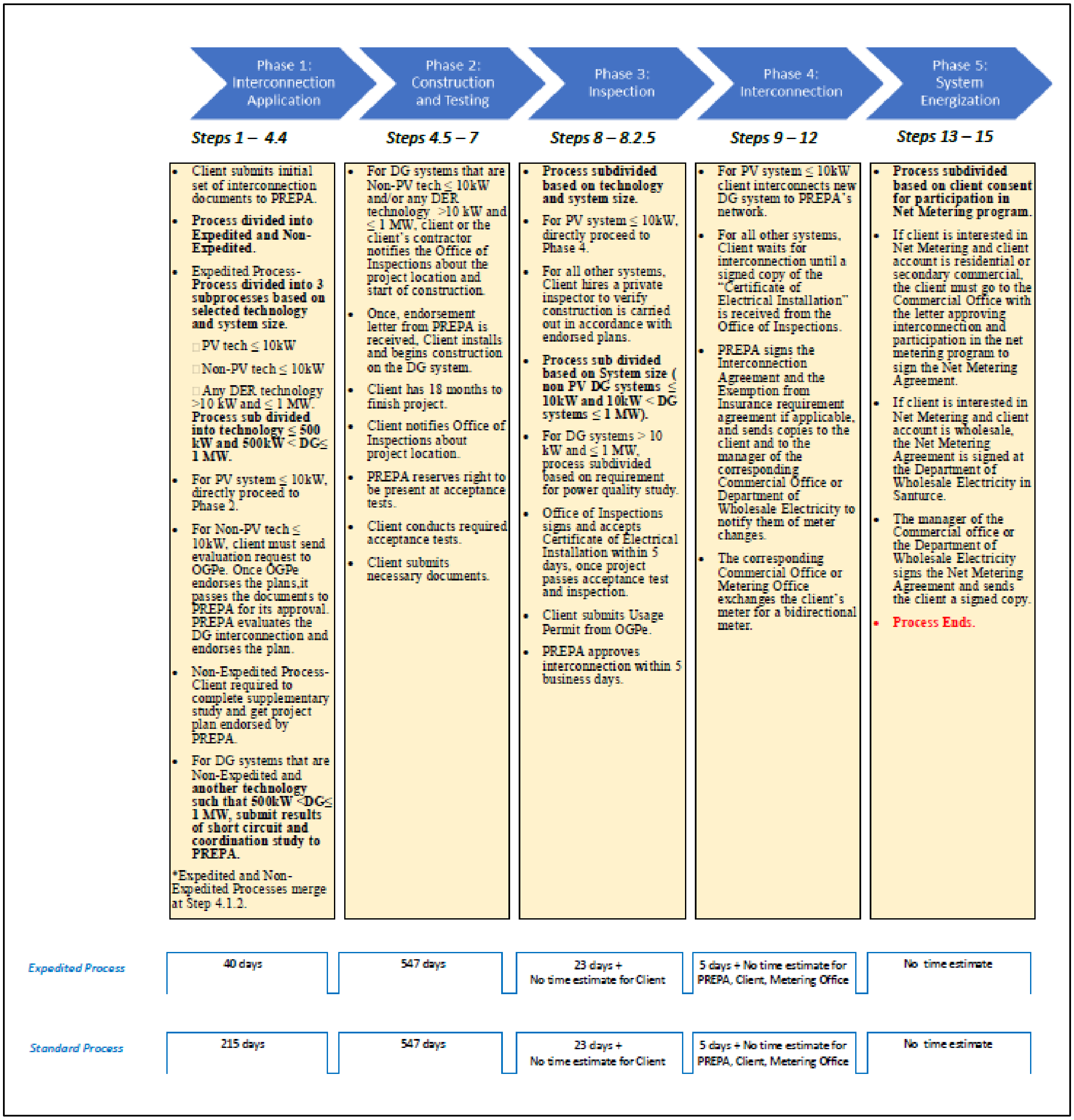


Figure 26. Overview of the DER interconnection process

The time periods at the bottom of the graph in Figure 26. For example, in Phase 2 the client is allowed up to 18 months to complete construction; however, a small residential distributed generation system might be completed in only a few days.

PREPA reserves the space for a DG interconnection based on the timelines stated in the regulation. For example, the regulation states that the Endorsement letter is valid for 12 months; so, as part of our DG integration analysis, PREPA reserves the space for that customer for at least the time period indicated. If the customer, after receiving the Endorsement letter and within the one-year period, starts the installation of the DG system, then PREPA reserves the space for this customer for an additional 18 months, as stated in the regulation. If the time period expires, and the customer does not interconnect the system, only then can PREPA remove the interconnection request from our analysis.[16] This significantly effects hosting capacity analysis.

4.2 Process Mapping

The functional flowchart developed as part of the analysis was extended into a set of process maps for easy visualization of each step, categorized primarily by the actor responsible for undertaking the action (entities involved in the process flow, such as the client and the Distribution Engineering Department) and the time constraint for each activity.

Systems engineering principles were incorporated to analyze the interconnection process through the development of activity diagrams (process maps) for the interconnection process.

Defining process boundaries at the point of exchange or handoff of responsibility is called "swim-lane" diagramming. Swim lanes can serve to clarify process ownership and responsibilities, duplication of efforts, and potentially locate bottlenecks and process delays. Swim lanes can allow the process analyst to identify limited or no-value-added exchanges or duplications of effort, which are opportunities to streamline processes.

A swim-lane structure in the process maps was used to guide quality inspectors and process improvement managers in the easy differentiation of responsibilities and handoffs in the process. The process was further subdivided into the expedited process flow and the standard process flow based on the requirement for conducting supplementary studies. Appendix B shows the detailed process maps (swim-lane diagrams) for the DER interconnection process.

A primary objective of developing the process maps is to identify the value-added and non-value-added activities in a process. Identifying and eliminating bottlenecks is a critical aspect of process analysis and is critical to increasing process capacity (throughput) while reducing time and cost. Symptoms or consequences of bottlenecks include process "starvation" and activity "blocking." Starvation occurs when a downstream activity is idle with no inputs to process because of upstream delays (bottlenecks). Blocking or congestion occurs when an activity becomes idle because the next activity is not ready to take it. Although buffers or queues can reduce these issues, taking inventory between activities might simply compensate for an inefficient bottleneck without improving the overall production of the process.

Analyzing timelines, work-in-process inventories (i.e., queues), and handoffs can reveal opportunities for improvement, including identifying process bottlenecks. Likewise, high-value but under-resourced tasks can be identified and highlighted for resource allocation (i.e., adding staff).

An evaluation of the queue size or work-in-process buffer volumes can also point to resource imbalances. If these factors are variable or changing, it might be effective to introduce flexibility by outsourcing certain activities. Evaluating the process flow diagram interconnections—that is, the arrows between steps—as inputs and outputs can allow the process owner and analyst to evaluate rework. If downstream processes are rejecting or otherwise returning material (such as

[16] Personal communications, Tomas Velez, PREPA, May 2020.

interconnection application forms), downstream requirements or specifications might be unclear or an opportunity for better instruction might exist.

4.3 Considerations for Potential Improvement by Interconnection Phase

4.3.1 Phase 1: Interconnection Application

The interconnection phase details the activities required for project commencement. Depending on the need to conduct a supplementary study (determined by PREPA), the activities are subdivided into two major process flows: expedited interconnection process and standard interconnection process. The expedited process is further subdivided into three categories based on the system size and type of technology used for the DER interconnection process.

An initial assessment of the interconnection application process was helpful in identifying areas for process improvement. Per the current process, the client is provided the option to submit an interconnection application in any of the three entities[17]: PREPA, OGPe, and the autonomous municipality. In hindsight, this might have been allowed to avoid inconvenience, but it inadvertently leads to ambiguity for the client, especially in cases where the online portal is not functional.

Another potential area for process improvement involves differentiating process activities into either the expedited or standard process.

Further redundancies were identified in the expedited and standard processes and are briefly discussed in the following sections.

4.3.1.1 Considerations for Improving the Expedited Process

DER systems that use PV technology and have system sizes of 10 kW or less are allowed to directly proceed to the construction and testing phase; however, the process induces lag times for systems that fall within the other two brackets, e.g., non-PV systems with sizes less than or equal to 10 kW and DER systems that use PV or non-PV technology but have system sizes greater than 10 kW and less than or equal to 1 MW.

These lags could be attributed to the following factors:

- Solicitation of a subset of documents already requested at the start of the application process
- Lack of a simple process interface for clients to comprehend the requirements and process (as set forth by the Joint Regulation for the Procurement, Evaluation, Selection, Negotiation and Award of Contracts for the Purchase of Energy and for the Procurement, Evaluation, Selection, Negotiation and Award Process for the Modernization of the Generation Fleet [PREB 2016])

[17] The *Reglamento Conjunto de Permisos*, a commonwealth integrated permits document, establishes which entities must accept interconnection requests.

- The requirement for endorsement of the distributed generation interconnection evaluation request from the OGPe prior to endorsement from PREPA.

4.3.1.2 Considerations for Improving the Standard Process

Because the expedited and standard processes merge at Step 4.1.2. of the interconnection process, the factors inducing lag times in the expedited process are also prevalent in the standard process. It was also noted that the process terminates abruptly if the client does not accept the results of the supplementary study. This opens the possibility of inducing a review process akin to Step 2.2, where the client can discuss and clarify the results of the evaluation before deciding to opt out of the interconnection process as a result of limited comprehension of the results generated from conducting the supplementary study.

The average difference in expected time between the two processes is currently 175 days (based on provided time constraints for activities in the PREPA interconnection flowchart). With further time delays and up-front costs carried on to the standard process because of the aforementioned factors, the client can be deterred from interconnecting their systems with the grid.

4.3.2 Phase 2: Construction and Testing

The construction and testing phase clusters activities that relate to system installation and acceptance testing. Based on an initial assessment of the requirements for commencing project construction and installation, it has been identified that there is inherent ambiguity in appropriately determining required permits and agencies involved in issuing endorsements for project installation. Another potential inquiry is directed at the provided option of submitting required permits and information through paperwork if the online portal is unavailable. This warrants additional information on the average downtime of the website hosting the submission portal and PREPA's ability to track associated paperwork for each unique project and user account in different formats.

4.3.3 Phase 3: Inspection

Once the project installation is complete, the client proceeds to the inspection stage for the DER system. The process is subdivided again into three process streams based on a combination of the system size (1-MW threshold with DERs ≤10 kW or DERs >10 kW) and type of system technology used (PV or non-PV). Distributed generation systems that use PV technology and have system sizes less than or equal to 10 kW can directly proceed to Phase 4. For all other distributed generation systems that do not satisfy this condition, the client is responsible for hiring a private inspector to verify that the construction is carried out in accordance with the endorsed project plans.

For systems less than or equal to 10 kW with a technology other than PV generation, the client submits the results of the preliminary inspection to the Office of Inspections for further review. Additionally, the client is required to procure and submit a usage permit from OGPe. These process delays and additional cost burdens result in a redundant loop that can deter the client from pursuing the project. A potential recommendation would be to eliminate the requirement for a usage permit for DER systems that use PV as the generation technology. This recommendation is supported by a detailed study on the integrated permit system in Puerto Rico, which was conducted by the U.S. Environmental Protection Agency in collaboration with NREL, Puerto Rico's DDEC, and the Environmental Quality Board of the Government of Puerto Rico. Once the client submits the required permits and certificates, the total cycle time for interconnection approval is efficiently constrained to 15 business days.

The third classification categorizes DER systems with sizes greater than 10 kW that require a power quality study. Although the interconnection document details the technical conditions required for a power quality study, it does not specify whether the client or the distribution provider is responsible for determining the need for a power quality study. Further, it does not explicitly inform the client of the estimated cost of conducting such a study. This opens the possibility of projects that get disconnected post system installation and sit idle in the interconnection queue longer, causing cost and time penalties for the client and PREPA.

To garner deeper insights and develop recommendations on the feasibility of the requirements for this review, the process was compared with the interconnection procedure elaborated in California Rule 21. It was found that power quality and voltage studies were included as part of supplemental studies for projects that qualified under the fast-track review. The distribution provider was tasked with determining the need for a power quality study and informing the applicant of the details for the study. To promote process transparency, the need for conducting a supplemental study and the associated costs were communicated to the client at the start of the interconnection application procedure. Additionally, projects that cleared the initial screens could bypass the supplemental study process and interconnect their systems with the distribution provider's network. This comparison opens the scope for process improvement to make it more transparent and keep the client abreast of the process requirements at all stages of the interconnection process.

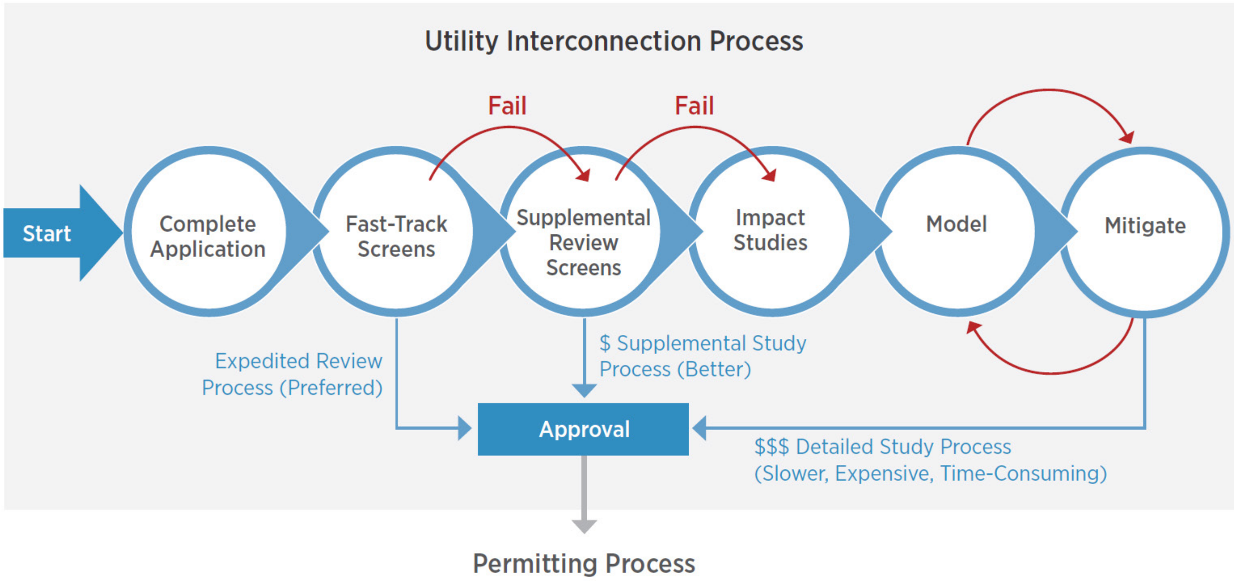
4.3.4 Phase 4: Interconnection

The activities in the penultimate stage of the interconnection process are clustered under Phase 4. For DER systems that use PV technology and are less than or equal to 10 kW, the client can directly proceed to system interconnection after submitting the certificate of installation. Based on the interconnection document provided by PREPA, there is ambiguity in determining whether the client is required to wait for endorsement of the certificate from PREPA's Office of Inspections and the regional Distribution Engineering Department.

For all other DER systems, the client is required to wait for the interconnection approval from PREPA's Distribution Engineering Department. The process phase terminates with the corresponding commercial office or metering office exchanging the client's meter for a bidirectional meter. Although this flows logically in sequence with the process for systems that are non-PV (≤10 kW) and any technology (>10 kW), this seems redundant for systems that are PV-based with system sizes ≤10 kW and are already interconnected with the network. (See flowchart, Appendix B, steps 8.1, 8.3, and 8.4 for non-PV systems sized ≤10 kW).

Another potential problem with analyzing bottlenecks in this phase is associated with the lack of specific time constraints imposed on activities conducted by the client, PREPA, and the metering office.

In a 2017 white paper developed under the Islands Energy Transitions Initiative (DOE 2017), the typical utility interconnection process is discussed. The process is illustrated in Figure 26.

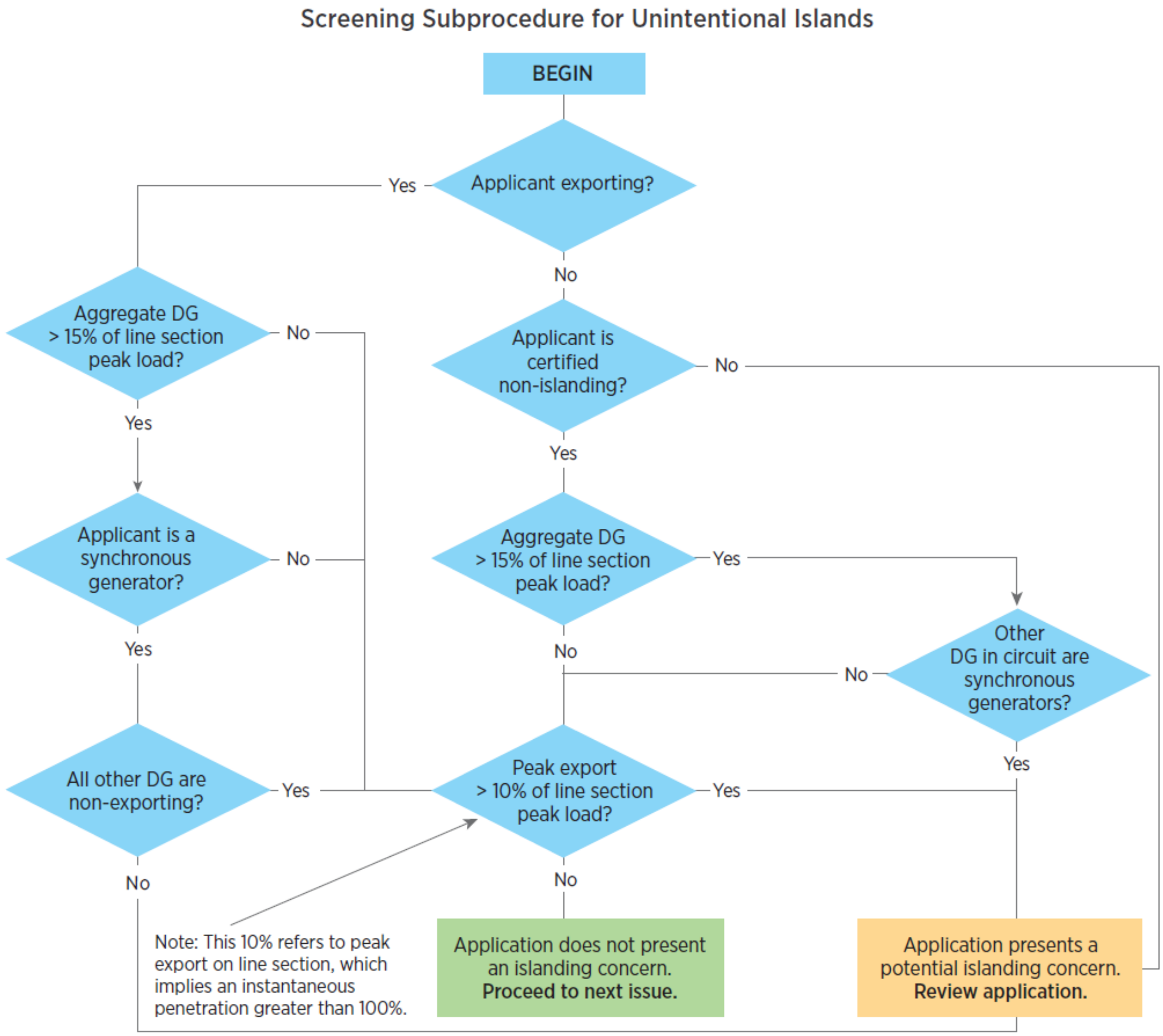


Source: DOE 2017

Figure 27. Example of typical utility interconnection process

As discussed in the white paper, best practices for updating interconnection screens include updating screens away from the 15% capacity penetration screen toward more appropriate and accurate capacity penetration metrics, such as the utilization of minimum daytime load as the first supplemental review screen. To pass this screen, the aggregate generating capacity on the line segment should be less than 100% of the line's historical minimum load. The team noted that though better than the 15% capacity penetration screen, even more accurate results could be obtained with new metrics that evaluate the conditions that could cause unintentional islands and voltage regulation issues (DOE 2017).

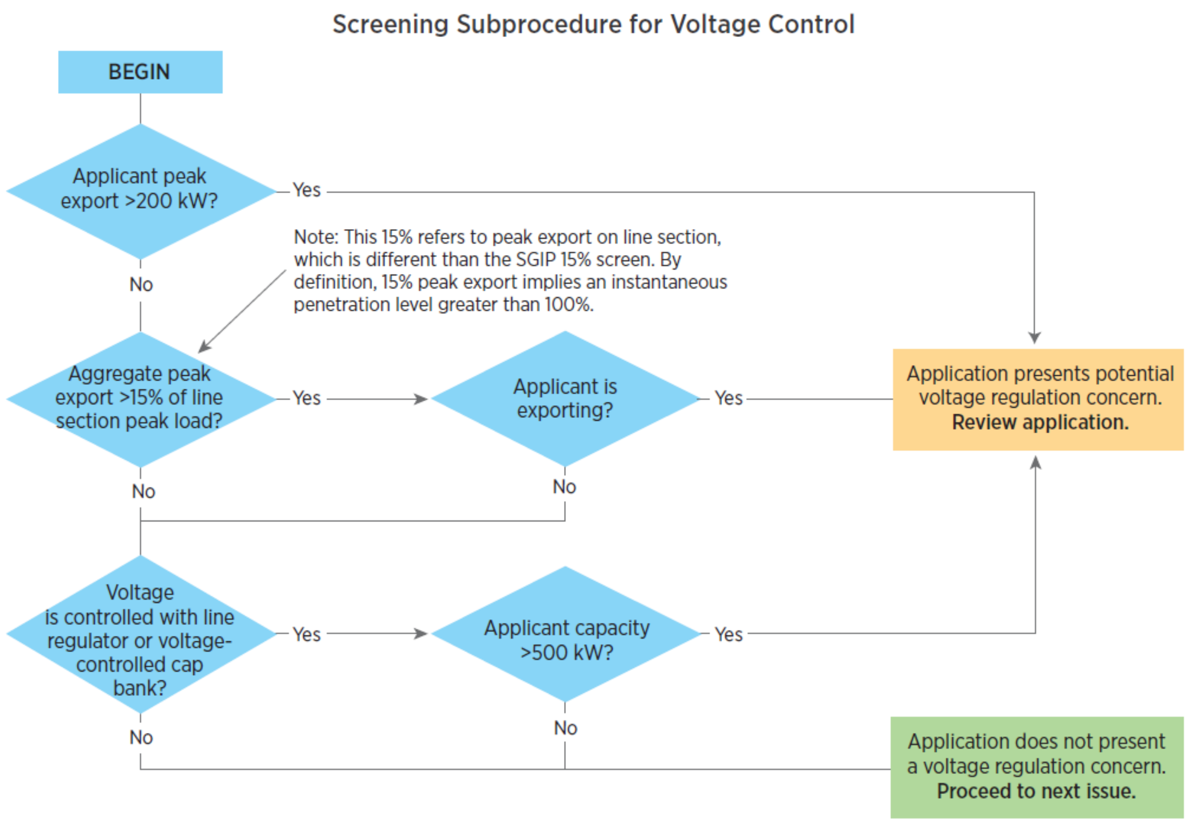
A revised screening subprocedure was recommended for evaluating the risk for unintentional islanding. This is illustrated in Figure 27.



Source: DOE 2017

Figure 28. New screening subprocedure for determining the risk of unintentional islanding

A new screen for determining the risk for voltage regulation concerns was also proposed, as shown in Figure 28.



Source: DOE 2017

Figure 29. New screening subprocedure for determining risk of voltage regulation concerns

Another recommendation made in the report specifically for inverter-based generators is the utilization of built-in features for the detection of and response to unintentional islanding and the utilization of voltage regulation capabilities to manage voltage concerns.

Additional mitigation strategies mentioned in the white paper are to develop hosting capacity maps and to make the distribution system more robust.

4.3.5 Phase 5: System Energization

The final stage of the process involves differentiating clients by their willingness to participate in the net metering process. Clients who want to participate in the process are categorized into residential, secondary commercial, and wholesale accounts and rerouted to either the commercial office or the department of wholesale electricity, depending on account type. Acknowledgment and official signature of the net metering agreement by the corresponding entity mark the end of the interconnection process. A review of the activities in this stage revealed redundancies, such as the need for physically delivering documents to the corresponding offices given that the commercial office already holds copies of the interconnection agreement provided by the client in Phase 4 (Flowchart Step 11) of the interconnection process. Although the client could sign the documents online, a potential recommendation for this phase involves automating this step by providing the client an option to also submit the net metering agreement through the online portal[18]. Additionally, the process activities in this phase currently lack a time constraint, resulting in uncertainties and inefficiencies.

4.3.6 Additional Considerations for Process Improvement

In addition to the mentioned recommendations, the following industry best practices have been identified for incorporation into the current process:

- **Use of online interconnection applications for PV developers and utility customers.** PREPA provides an online "portal" for the interconnection application, yet interviews with stakeholders identified issues with access, reliability, and accuracy. From analyzing the current process, it was not clear how the portal was used. An assessment of the portal is recommended, including reporting, notifications, access rights, cybersecurity, and integration with other PREPA systems (e.g., geographic information system).
- **Online tracking of PV application for both utility workers and DER stakeholders.** Based on interviews with PREPA engineers and DER stakeholders, the portal affords PREPA staff the facility to track applications, but this feature is not available to the public at this time.
- **Use of the latest revision of national standards to ensure power quality and safety (UL 1741 and IEEE Std 1547).** The adoption and implementation of consensus-based national standards specify equipment performance characteristics and reduce total overall cost by minimizing customization. In addition, certification standards such as UL 1741 ensure that installed DERs conform to safety and technical functional performance requirements.
- **Need for implementation profile.** IEEE Std 1547-2018 specifies three communications protocols that meet interoperability requirements in the standard. Based on lessons from the implementation of interoperability requirements in California under Rule 21, an implementation profile such as the *Common Smart Inverter Profile* is important and needed guidance for both utility and DER operators.
- **Tracking all DER systems on a geographic information system.** Analysis of existing and new interconnection agreements is improved through tracking in a geographic information system. This should include timely updates to systems with PV that are attached to the correct area in the distribution system and with significant detail on the size and type of technology. This information can supplement field measurements to support modeling and simulation. Distributed generation interconnection information is included in PREPA's geographic information system; however, adequate resources should be dedicated to ensuring timely maintenance and updates.

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[18] After discussion with PREPA, it was learned that the client can sign the agreement electronically through the portal (this agreement includes the interconnection of the DG system and the participation in the Net Metering Program). The online portal also provides the availability for the customer to sign the agreement electronically. But, since the approval of Act 17-2019 changed the interconnection process for the DG systems with capacities up to 25 kW, these customers can submit the documents in paper at PREPA offices, so that the interconnection process can be competed in 30 days, as stated in the Law (as of June 2020, the portal is in the reconfiguration process so that, for DG systems up to 25 kW, it can adequately handle these interconnection requests with the "modified process", as stated in Law 17-2019). (personal communications, Tomas Velez, PREPA, May 2020).

- **Proactive application of value stream analysis tools to identify and minimize inefficiencies.** As Puerto Rico updates the current interconnection rule, proactively applying the tools described in this section could preemptively identify process bottlenecks and value/non-value-added steps in the new DER interconnection standard for the commonwealth. This analysis should build on the process maps and audit diagrams developed here and extend their functionality through value stream analysis. Value stream analysis captures the flow of work, material, and information, and it identifies key (sub)process metrics.
- **Education and training.** Based on interviews, stakeholders believe there is a large education gap in Puerto Rico on the topic of advanced inverter functionality, information on the status of technological developments, and what that might mean for power systems operation. Stakeholders would also like more information on the microgrid requirements component of IEEE Std 1547-2018. NREL has curated a list of publicly available educational resources to aid stakeholders with DER interconnection. The resources include introductory presentations and white papers written by industry practitioners as well as more topic-specific DOE technical reports focusing on requirements in IEEE Std 1547-2018. NREL is continuously adding new material related to the adoption and implementation of the standard. The resource site is located at https://www.nrel.gov/grid/ieee-standard-1547/.

4.3.7 Recent Efforts to Update Interconnection Rules

As of this writing, recent efforts to update interconnection rules are limited to a few states. Only six states revised their DER interconnection standards in the past 2 years. New York, North Carolina, and Minnesota recently revised their interconnection standards to respond to changing process and technical requirements. Other states are also initiating updates. One main reason for these updates is that an important technical standard, IEEE Std 1547-2018, was updated in April 2018.

The New York Public Service Commission updated its *Standard Interconnection Requirement* in October 2018, only a few months after the release of IEEE Std 1547-2018. The update focuses on standards for interconnecting energy storage systems up to 5 MW AC. These standards apply to new hybrid projects, stand-alone projects, the addition of energy storage to an existing distributed generation facility, and to changing the operating mode of an existing facility. The requirements "are intended to be consistent with those contained in the most current version of IEEE Std 1547" (New York State Department Public Service Commission 2019).

Similarly, the North Carolina Utilities Commission issued an order in June 2019 revising its interconnection standard to include provisions for adding energy storage at existing PV sites and to include an expedited interconnection study for certain small biomass-energy facilities. Further, the North Carolina Utilities Commission ordered that the regulated utilities will commence stakeholder meetings in 2020 on the adoption and integration of IEEE Std 1547-2018 into the North Carolina interconnection standards and will report to the commission in August 2020.

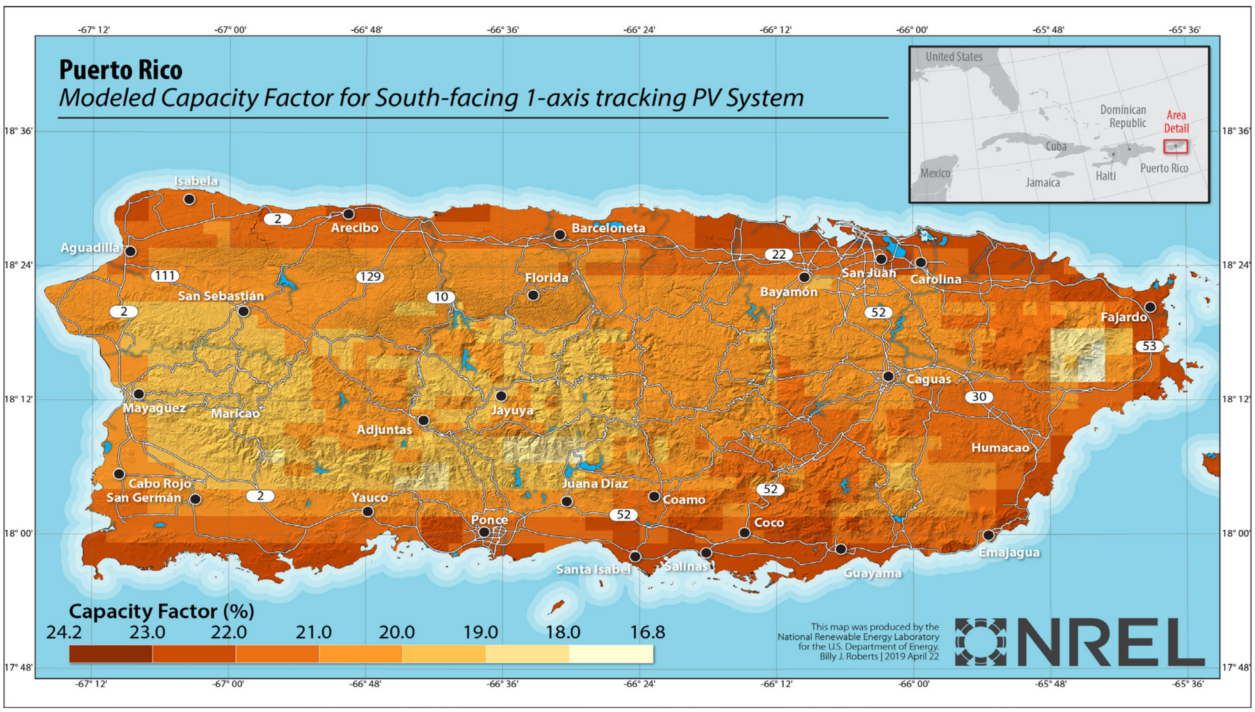
Although Minnesota initiated an update to its statewide interconnection standards in 2017, the final 2019 rule is one of the first in the United States to incorporate the latest updates to IEEE Std 1547-2018. One of the earliest tasks was convening a set of stakeholders under the Distributed Generation Workgroup, including input from the Midcontinent Independent System

Operator as the regional reliability coordinator. The update was addressed in two phases. The topics discussed in Phase 1 included the pre-application report, application requirements, interconnection queue process, application process paths (simplified, fast track, and study), key terms and definitions, the transmission provider's role, engineering screens for initial and supplemental review, study processes, dispute resolution, testing, and the interconnection agreement. Phase II discussion items included the application of specific technical capabilities, including those enabled under IEEE Std 1547-2018. These included the DER normal and abnormal performance categories, discussion on Midcontinent Independent System Operator bulk power system reliability considerations, reactive power and voltage/power control, equipment protection requirements, energy storage, power control limits, interoperability, and cybersecurity (Rosier 2018). The final *State of Minnesota Distributed Energy Resource Interconnection* Process , effective June 2019, contains sections on (1) applying for interconnection; (2) a simplified interconnection process; (3) a fast-track process; (4) the study process; and (5) provisions that apply to all interconnection applications, including specific requirements for inverter-based DERs. The final *State of Minnesota Technical Interconnection and Interoperability Requirements*, effective July 1, 2020, are based on IEEE Std 1547-2018 and contain sections corresponding to each clause in the standard. Both documents and more information can be found at https://mn.gov/puc/energy/distributed-energy/interconnection/.

5 Potential for Increasing the Physical Resilience of Distributed Energy Resources

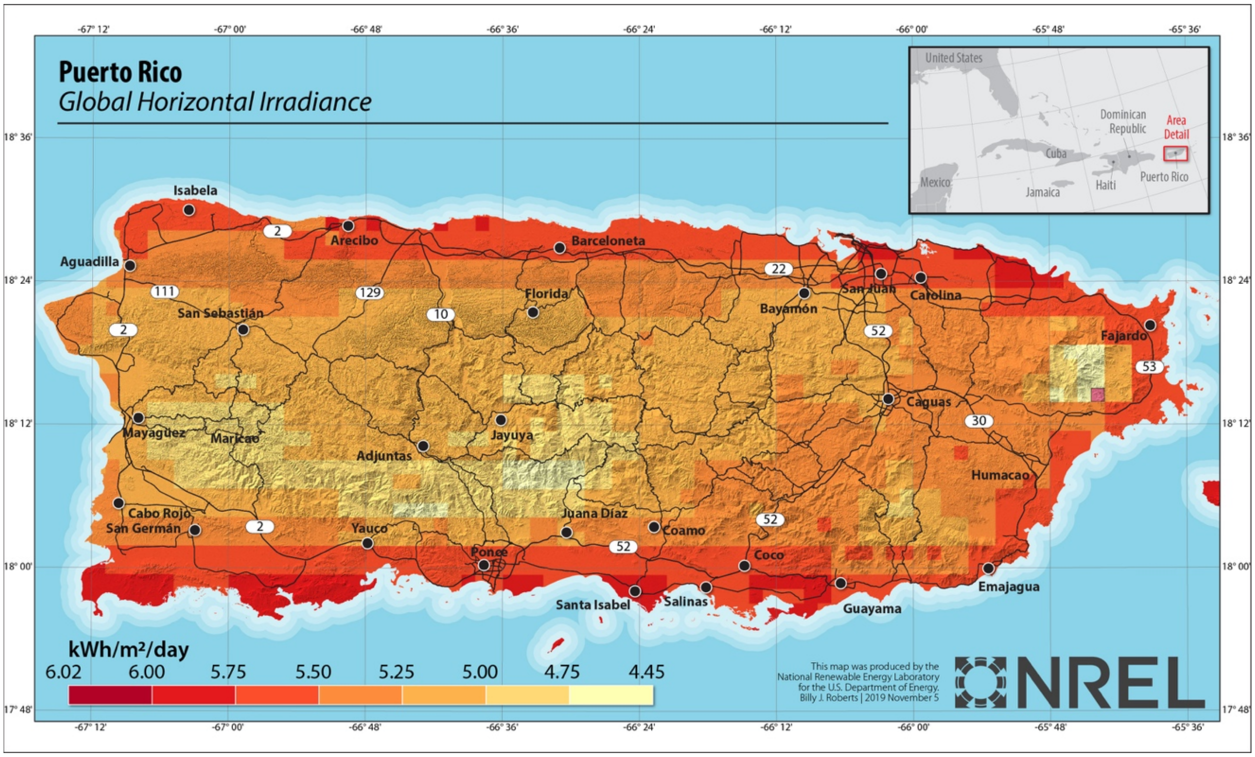
On-site energy generation can be a resilience strategy, if designed appropriately. Using technologies such as PV to provide power to a site during a large-scale grid outage can be an effective solution for enhancing resilience. Resilience in this context is typically measured by the ability of a system or organization to reduce the impacts of threats and vulnerabilities.

Puerto Rico, for example, has a valuable solar resource, making PV a viable renewable energy technology for on-site energy generation. See Figure 30 and Figure 31. Systems designed to be more resilient should include well-designed (e.g., consider wind-loading standards) PV panels with secure racking systems, backup energy storage (e.g., battery systems), and islanding controls—and related policy—to disconnect from the grid and operate in a safe and independent mode. Solar water heating systems can also be used to supply hot water to building occupants when the grid system is down. Both technologies can reduce operational costs during typical conditions while providing on-site generation (or offset, in the case of solar water heating) during disruptive events.



Source: Grue et al. 2021

Figure 30. Multiyear mean capacity factors



Source: Grue et al. 2021

Figure 31. Annual average global horizontal irradiance for Puerto Rico

The FEMA *Mitigation Assessment Team Report* found that most PV systems installed prior to Hurricane María were permitted—a requirement for interconnection with the grid system; however, codes only require systems costing more than $6,000 to be permitted, and most solar water heaters fall below this threshold, and therefore they typically do not require inspection upon installation. This lack of inspection or permitting process creates a network of installations of unknown quality and construction—thus increasing overall system risk during a major weather or geologic event (FEMA 2018). The *Mitigation Assessment Team Report* also found that there is a lack of guidance for designing and siting solar technologies, apart from the interconnection of PV. As noted, "this lack of guidance is especially noteworthy given that local permitting does not review or inspect PV panels or solar heating system installations" (FEMA 2018). Two major challenges with PV during Hurricane María included panels being struck by wind-borne debris (e.g., an antennae or tower falling over and crushing PV panels); and racking and through-bolting not being installed properly, which caused the panels to loosen under dynamic wind loads and separate from the racking system—and become wind-borne debris. See Figure 32 for example destruction of PV system. Note that in post-storm conditions, the ability to generate power from on-site generation is tied to both the robustness of the technology and the policy that allows or disallows operation in islanded mode.

There are many benefits to incorporating safe on-site generation systems. During future storms, resilient on-site solar and storage would allow occupants to shelter in place. If rooftop systems are designed and installed safely and securely, and if they are paired with energy storage systems and inverters that can island from the larger grid, the impacts related to widespread power outages can be minimized. On-site energy generation and storage, along with strategically placed microgrids on the grid system, have the potential to reduce the impact on Puerto Rico's residents and reduce economic losses as well.

Appropriate siting and design must be included in the design features if PV systems are to provide power in post-storm scenarios. FEMA noted that "the performance of PV power systems varied depending on the type of anchoring system and the type of clamping system connecting the PV panels to the aluminum frame" (FEMA 2018). The 2018 Puerto Rico building codes mandate that "wind loads on every building or structure shall be determined in accordance with Chapters 26 to 31 of ASCE 7" (Puerto Rico Permits Management Office 2018). This document incorporates many standards for building codes in the United States, and the American Society of Civil Engineers (ASCE) publication on "*Minimum Design Loads and Associated Criteria for Buildings and Other Structures* (ASCE 2016) describes the means for determining dead, live, soil, flood, tsunami, snow, rain, atmospheric ice, earthquake, and wind loads and their combinations for general structural design (ASCE 2016). The inclusion of ASCE 7-16 is a significant step forward in enhancing the safe siting of rooftop PV and thermal systems because it includes guidance for wind loading on building-mounted arrays (ASCE 2016). There is no current ASCE design standard for ground-mounted PV; however, there are standards in other countries (e.g., Japan and Taiwan) that might be useful examples for resilience.[19]

To maximize the survivability of systems under disaster conditions, roof-mounted and ground-mounted solar technologies can be designed to static wind-loading conditions as well as dynamic wind-loading conditions, especially in Puerto Rico, where hurricane-related winds are more prevalent. The codes could be reviewed, potentially by the Office of Inspections, to determine whether these standards are currently required and to provide the tools for designers and installers to verify that installation techniques are adequate, and the workforce should be trained on safe installation practices and verification during commissioning of the system.

Figure 32. PV system damaged by Hurricane Irma, U.S. Virgin Islands. Note the missing panels in the top left. *Photo by Michael Ingram, NREL*

Studies were conducted following Hurricane María to determine the points of failure in PV systems. In reviews conducted by NREL, Lawrence Berkeley National Laboratory, and the Rocky Mountain Institute, there were six technological categories of failure:

1. PV module frame and laminate

[19] Testing in Taiwan's research institute, ITRI, uses dynamic wind-loading test criteria of 5,000 Pa for 200 cycles to simulate the strongest possible typhoon, which is more than Level 17 on the Beaufort scale. With less than 0.29% power degradation, a Japanese test module has been shown to survive in wind speeds faster than 220 km/h (130m/h) when mounted on an equally secure mounting system.

2. Module connection hardware
3. Structural racking member
4. Structural racking connections
5. Racking foundations
6. Electrical balance of systems.[20]

Each category is summarized in the following subsections as lessons learned for resilient siting considerations.

5.1 Photovoltaic Module Frame and Laminate

PV frame and laminate failures following Hurricane María were all related to the panel itself tearing out of the frame or to impact damage from flying debris (see Figure 32 for an example of frame damage). To limit the failure of the frame and panels, project developers should ensure that the system design meets wind-loading and pressure specifications. UL 1703 (UL 2002) is the standard for flat-plate PV modules and panels and includes information on static loads. System designers should ensure that modules and panels meet static load requirements specific to each deployment site—that is, each location for the possible deployment of PV should be assessed for local topography and wind conditions before choosing the equipment type. Because the standard accounts for only static loading, it might be useful to incorporate topography and dynamic wind loading into a model of a planned solar array. This option might not be viable in all cases because of financial or timing constraints.

[20] For the full report on failure modes and solutions for ground-mounted PV, see *Solar Under Storm: Select Best Practices for Resilient Ground-Mount PV systems with Solar Exposure* (Burgess and Goodman 2018), https://rmi.org/wp-content/uploads/2018/06/Islands_SolarUnderStorm_Report_digitalJune122018.pdf.

Figure 33. PV module torn from racking, lying facedown, shows laminate failure. ***Photo by Eliza Hotchkiss, NREL***

Minimizing debris can increase system survivability. This includes regular maintenance of vegetation at or near the site as well as removal of any small equipment that is not firmly secured. Additionally, pre-hurricane preparations could include the removal of any objects of concern that might become airborne during storm conditions. Siting PV systems outside of areas of impact can also be useful. In hurricane-prone areas, additional siting considerations related to flying debris can be integrated into initial planning at system introduction.

5.2 Photovoltaic Module Connection Hardware

Another mode of failure observed after Hurricane María involves the hardware that attaches the PV modules to the racking. Hardware failure occurs through loosening of bolts, rotation of clamps, and a subsequent cascading failure of hardware. Loosening of bolts can occur in any location with rapid pressure or temperature swings or because of vibrations in the system. Specifying bolt-locking hardware could be included in specifications for installations. Additionally, pre-hurricane preparation could include torque checks; however, this is labor intensive and will require diligent maintenance and verification processes. The Puerto Rico Office of Permits Inspection and Management or offices of emergency management could facilitate this process.

Hardware failure in Hurricane María was noted to be caused by undersized racking systems compared to load (Robinson, Walker, and Fu 2018). Similar to PV model frames, hardware should be specified based on the local conditions expected at each PV array site. Note also that large ground-mounted arrays might have varying conditions across the site based on topography. Hardware should be sized based on maximum expected load on the array.

Failure of one hardware connection can, in some cases, cause cascading failures that result in the loss of multiple panels (see Figure 33 for an example of hardware failure).

Source: Robinson, Walker, and Fu 2018

Figure 34. Examples of failure of clamp (top left of photo) causing attached modules to overturn

In Puerto Rico, this was particularly true of T-clamps that rotated with the loss of one clamp and subsequently allowed the loss of multiple modules. The studies following the hurricane recommended that modules be through-bolted, rather than T-clamped, to mitigate this vulnerability (Robinson, Walker, and Fu 2018; Burgess and Goodman 2018). Alternatively, clamps that do not rotate and allow the freeing of modules subsequent to single failure could be employed.

5.3 Structural Racking Member

Structural racking members were another common point of failure of PV arrays during Hurricane María. These failures largely resulted from inadequate materials and design for appropriate wind loads. ASCE 7-16 details wind loads for structural design. This code was designed for buildings but could also be employed for any ground structure, such as a utility-scale PV array. Additionally, PV arrays should be analyzed for their interference with airflow. It was noted that some solar power plants experienced dynamic (mechanical) excitation when natural frequencies matched vortex-shedding frequencies. Modeling these mechanical frequencies for each solar power plant should reduce racking failures associated with dynamic amplification.[21]

Finally, solar arrays built on tracking systems had a high rate of failure because of torsion on the torque tubes. Dynamic wind modeling of each tracking array in hurricane zones could be considered—if tracking must be employed at all at the latitude. The high failure rates of tracking arrays might necessitate the use of fixed-tilt solar arrays in areas that have a high likelihood of category 4 and 5 hurricanes. An analysis could also be conducted to determine whether tracking systems are, in fact, cost-effective in hurricane-prone regions. Typically, tracking systems are used to track the sun's progress across the sky from dawn to dusk to allow panels to absorb as much solar energy as possible. In locations such as the Caribbean, which are close to the equator, the tilt angle of the panels is less severe than in northern locations, such as Alaska. This means

[21] More information is available from the Solar Energy Industries Association; see www.seia.org/sites/default/files/Cain%20and%20Banks%20Utility%20Scale%20Wind%20Presentation%202015%20SEAOC%20Convention.pdf.

that the tilt angle in Puerto Rico could be close to 0°, minimizing the need for tracking and maximizing efficiency.

5.4 Structural Racking Connections

Similar to the module mounting bolts, structural racking bolts loosened during Hurricane María. Connections should include specifications for bolt-locking mechanisms to prevent this from occurring. Other modes of failure included shearing of bolts and self-tapping screws. In both cases, hardware specifications should be updated based on the (1) expected wind-loading conditions, (2) 25–30-year life span of the array (or replaced at specified intervals), and (3) expected vibration during storm events. Preventing shear of the connections will aid in survivability of the entire solar power plant by also reducing airborne debris during a major storm.

Source: Robinson, Walker, and Fu (2018)

Figure 35. Examples of hardware failure

5.5 Racking Foundations

Racking foundations of solar arrays failed during Hurricane María for several reasons, including foundational structure failure, overturning of foundation posts, erosion, and corrosion. Instances of foundation structural failure might be reduced only through site-specific geotechnical studies and mitigation. Geotechnical studies should be performed on foundations for utility-scale arrays located in hurricane zones to reduce the risk of failure. Researching the geologic conditions prior to system design will be useful to ensure more stable system design. Overturning foundation posts might be mitigated through reducing the angle of panels, thus reducing the momentum on the system. Erosion at or near foundations should be reduced through standard hydrologic/runoff modeling and subsequent drainage planning. Site-specific drainage plans should be created based on local topography and site conditions. Finally, corrosion could be addressed through additional galvanization of components. This might be cost-prohibitive, so galvanization could be limited to the most critical components.

5.6 Electrical Balance of Systems

Finally, additional failures were caused through losses of the electrical balance of systems, including wiring, inverters, and combiner boxes. Wire pullout could be mitigated by specifying torque at points of coupling. Additionally, pre-hurricane preparation should include checks for appropriate torque on connections. Wires should also be regularly checked for sheathing condition and sagging. In both cases, these conditions caused failure during Hurricane María. Finally, combiner boxes and inverters should be fully weather-sealed according to the National Electrical Manufacturers Association (NEMA) 4 standards against significant rain events and should be properly secured (NEMA 2019).[22] Pre-hurricane preparation should include checks of weather seals and locking mechanisms to prevent water intrusion.

5.7 Distributed Energy Resource Roof-Mounted Design and Best Practices

Roof-mounted DERs must consider the loads on both the PV array and the rooftop. As the *New York Solar Guidebook for Local Government* notes, "Solar electric contractors are responsible for ensuring that their installations do not jeopardize the structural integrity of the buildings upon which they are mounted. Due to their large surface areas, PV arrays can catch updrafts and create significant amounts of uplift during windy conditions" (NY-Sun 2019). As such, rooftop systems should be assessed for location-specific wind loads. In the case of Puerto Rico, Category 5 hurricane winds should be assumed possible. Some states, however, such as California, note that certain regions have unusual wind patterns and adjust regional wind load requirements accordingly (State of California 2019). Wind loading on rooftop systems depend on the topography of the roof as well as the array design. Modules located high above the roof surface, at the ridge of the roof, or overhanging the roof tend to be subject to greater wind forces. The prevailing direction of wind could also be considered in siting roof-mounted arrays to minimize loads. The permitting process might require review of these loads under the authority having jurisdiction inspection.[23, 24, 25]

The number and dispersed nature of roof-mounted systems makes prestorm system preparation by qualified personnel particularly challenging. As such, constructing roof-mounted systems with more robust racking, bolting, and modules could aid in survivability without increasing maintenance checks. For example, systems installed with wedge-lock hardware, rather than split washers and nylon nuts, tend to perform better under vibration conditions associated with hurricanes (DOE 2018). Systems might also be powered down to ensure that damage from possible water infiltration is kept to a minimum. Systems should be allowed time to dry after major storms. Optimally, system components would be cleaned and tested by a qualified installer in a post-storm environment; however, the nature of small DERs might make this infeasible.

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[22] NEMA enclosure rating minimally 4, 4X or equivalent, recommended; 6 or 6P might be specified for certain facilities. NEMA 4/4X enclosures are "watertight"; NEMA 6/6P are capable of withstanding submergence.

[23] An example checklist, from the New York State Energy Research and Development Authority, can be found at https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Communities-and-Local-Governments/Solar-Guidebook-for-Local-Governments.

[24] An example of solar array checks, including wind uplift, from the Los Angeles area can be found at http://dpw.lacounty.gov/bsd/lib/fp/Small%20Residential%20Rooftop%20Solar%20Energy%20Systems/BCM%206807%20Article%201%20-%20Expedited%20Permitting%20Process%20for%20Small%20Residential%20Rooftop%20Solar%20Energy%20Systems%20COMPLETE%20POLICY%2004-04-16.pdf.

[25] California expedites solar permitting that meets structural criteria; see page 70 of the *California Solar Permitting Guidebook*: https://energycenter.org/sites/default/files/docs/nav/policy/research-and-reports/California_Solar_Permitting_Guidebook_2015.pdf.

5.8 Distributed Energy Resource Ground-Mounted Design and Best Practices

Similar to roof-mounted systems, ground-mounted arrays should be designed for maximum expected wind conditions. The ground topography has greater influence on ground-mounted systems and should be evaluated on a site-by-site basis. Modules in hurricane-prone areas should replace clamping with through-bolting to minimize module loss. These fasteners should be approved for use in coastal areas where corrosion is expected. Other site considerations include design of appropriate water drainage and avoidance of low-lying or flood-prone areas. It has been noted that perimeter fences can be designed to calm winds and reduce damage to solar arrays. These fences might also aid in reducing debris impacts to the array during a storm.

Ground-mounted arrays might have dedicated operation-and-maintenance staff that make pre-storm preparations more feasible. Pre-storm checks should include balance-of-system checks to ensure that connections are appropriately torqued, the site is cleaned of potential debris that could damage the system, and the system is powered down to minimize damage. Post-storm maintenance should include drying components, testing for faults, and replacing damaged equipment (DOE 2018).

5.9 Outreach and Workshop Summary

After assessing the baseline for building codes and on-site energy generation, next steps are provided for consideration by government organizations in Puerto Rico. The opportunities summarized in this section were presented in a DOE-sponsored workshop in San Juan on June 19, 2019. Thirty-two participants attended the session, representing federal entities (U.S. Department of Energy, National Renewable Energy Laboratory, U.S. Department of Housing and Urban Development, Federal Emergency Management Agency), Puerto Rican government entities (Polytechnic University of Puerto Rico, University of Puerto Rico, Puerto Rico Planning Board, Puerto Rico Energy Bureau, Puerto Rico Public Housing Administration, Department of Economic Development and Commerce, Vivienda, and Puerto Rico Electric Power Authority), and private-sector participants (Accurate Solutions; Blue Planet Energy; CSM; DexGrid; EcoÉlectrica, Interstate Renewable Energy Council; Konsol, LLC, Martinal; and Solartek LLC). Feedback on the implementation and gaps associated with opportunities was provided in the June workshop. This section summarizes the recommendations, gaps, and potential next steps. Note that feedback on building energy will be provided in a second, related report. Table 9 highlights the opportunities presented in Puerto Rico in June 2019.

5.10 Summary of Distributed Energy Resource Storm-Hardening Recommendations

A summary of the preliminary recommendations for enhancing resilience through codes and standards in Puerto Rico is provided for consideration.

Table 9. Summary of DER Storm-Hardening Recommendations

Category	Gap/Issues	Opportunity/Solutions
On-site energy generation	Lack of codes for resilient siting of solar arrays, including wind-loading requirements, racking specifications, and site modeling (for large arrays only)	Review solar installation requirements to ensure that roof-mounted and ground-mounted solar technologies are designed to static wind-loading conditions as well as dynamic wind-loading conditions (DDEC).
	Site inspections lack detailed verification of bolting torque, appropriately protected balance of systems, and limited potential debris	Field verification could be conducted on large systems to ensure safe installation practices.
	Site characteristics might increase vulnerabilities during storm events—particularly after significant rainfall or flooding	Consider conducting geotechnical studies on utility-scale array foundations located in hurricane zones.
Outreach	Workforce engagement noted confusion over site requirements, potential codes, and best practices	Workforce development strategies could enhance implementation and build knowledge of secure PV installation and building code designs and enforcement (Asociacón de Contratistas y Consultores de Energía Renovable [ACONER], the Association of Contractors and Consultants of Renewable Energy of Puerto Rico).
	Lack of adequate outreach and education	Create a communications plan to share information about resilience programs.
Emergency preparedness	Potential improvement	Checklists for pre-hurricane preparation could be developed to secure and prepare solar arrays for coming storms. These checklists would include items such as removal of potential debris, checks to ensure adequate weather sealing on combiner boxes and inverters, and torque checks for all connections and bolts.

Roof-mounted, small ground-mounted, and utility-scale solar technologies could be designed to static wind-loading conditions as well as dynamic wind-loading conditions. A review of the codes could determine whether these standards are currently being required and provide the tools for designers and installers to verify that installation techniques are adequate, and the workforce should be trained on safe installation practices and verification during commissioning of the system. Field verification could be conducted on every large ground-mounted system to ensure safe installation practices.

Geotechnical studies could be performed on foundations for utility-scale arrays located in hurricane zones. Minimally, researching the geologic conditions prior to system design will help ensure more stable system design. Further, site-specific drainage plans should be created based on local topography and site conditions. Soil stability should be studied under a variety of conditions. Multiple workshop participants noted that Hurricane Irma left soils saturated prior to Hurricane María landfall, contributing to overall instability in foundations.

Incorporating microgrids to lessen the stability burden of the broader grid system and enhance remote-area resilience could be a strategy to consider. Current analysis being conducted at Sandia National Laboratories and at the Massachusetts Institute of Technology Lincoln Laboratory seeks to prioritize microgrid locations based on social services provided in local areas.

Engagement with Puerto Rico agencies on the strategies for resilience might prove useful. Ultimately, implementing new resilience codes will rely on support from numerous stakeholders. The public must be made aware of the new codes—as well as the need for them. The public should also be consulted on customer fees related to enforcing codes. Codes should be made easily accessible to the public in both Spanish and English, and summary codes might also be made available for general consumption.

Workforce development and training is likely needed. Agencies such as the permitting office, OGPe, PREPA, and local jurisdictions having authority will likely need to be trained on resilience standards and how to ensure that structures are compliant. Multiple workshop participants noted that checklists relating to pre-hurricane preparations for solar arrays would be particularly useful.

6 Stakeholder Comments During On-Site Workshops

NREL conducted two workshops in Puerto Rico on improving distributed generation interconnection and interoperability through performance standards, focusing on the updated IEEE Std 1547-2018. A workshop was held in San Juan on April 23, 2019, for 13 participants, and another was held in Ponce on April 26, 2019, for 30 participants. NREL also met with a variety of stakeholders between April 22–26, 2019, to discuss the recent release of Law 17-2019 and general stakeholder experience with the distributed generation interconnection process in Puerto Rico. NREL met with representatives from ACONER, Solar and Energy Storage Association, PREPA, PREB, EcoEléctrica, and the University of Puerto Rico at Mayagüez, along with individual developers.

Key stakeholder comments on topics related to distributed generation interconnection and the Puerto Rico energy and policy landscape are presented as follows:

- **Act 17**: Stakeholders are hopeful that the new law will accelerate renewable energy deployment in Puerto Rico, particularly at the distribution level. Timelines for penetration targets are viewed as overly optimistic, but stakeholders are happy with the removal of various barriers to interconnection that previously limited the growth of distributed generation.
- **Enforcement of RPS targets**: Enforcement is viewed as a potential problem because Puerto Rico had established RPS targets before Act 17-2019, but penetration levels remained extremely low. Stakeholders hope that PREB will act as a strong regulating authority.
- **Delays in the interconnection process**: The most common stakeholder complaint is the length of time it takes for a response during each step of the interconnection process. Multi-month delays are very common, with many completed systems waiting up to 6 months to energize.
- **Online portal for interconnection applications**: All interconnection requests are processed through PREPA's online portal, which was created to streamline and expedite the interconnection process; however, technical website issues have been preventing applications from moving forward. Developers would like the option of submitting documents manually when the website is down and suggest that PREPA adopt best practices from other utility regions with similar online application processes to improve the portal.
- **Lack of uniformity across the seven PREPA regions**: Depending on where the distributed generation system is installed, the regional PREPA office might have different requirements and timelines and request different types of documents during the interconnection process. Clients say they would benefit from a standardized approach and coordination among regions.
- **Equipment requirements for interconnection**: Stakeholders believe that PREPA has been too aggressive in adopting some technical requirements from other states with much higher renewable generation penetration levels. They believe that the timeline for enabling advanced functionality should be tied to the level of distributed generation penetration and that new standards should be phased in more slowly to give developers enough time to adapt to the changes. Many stakeholders feel that the existing frequency

and voltage ride-through and rapid shutdown requirements were adopted too early, serving only to increase costs and cause delays.

- **Grid modernization**: Stakeholders view Puerto Rico's power system as technologically lagging compared to the rest of the United States, especially at the distribution level. Further, a lack of historical data makes any modeling and analysis effort difficult. Stakeholders hope that the planned privatization of PREPA will advance Puerto Rico's power system by bringing automation, smart meters, remote sensing, and distribution supervisory control and data acquisition systems.
- **IRP**: Stakeholders see the IRP as an important milestone to establish Puerto Rico's current baseline and to release external funds for progress moving forward; however, stakeholders are wary of the results of the studies conducted for the IRP. Many feel that only a limited range of options were explored and that the inputs and assumptions to the modeling efforts limited the possible outcomes of the study. Further, stakeholders feel that the IRP did not reflect the actual maintenance conditions of PREPA's assets or consider advanced inverter functionality.
- **Quality of installations**: After Hurricane María, many external entities are interested in working on energy issues in Puerto Rico. Stakeholders are worried about the lack of coordination between groups and the lack of a vetting process that might result in lower quality installations for the island in the long run.
- **Supply chain issues and available workforce**: Stakeholders point out that equipment takes a long time to arrive in Puerto Rico, often lagging developments in the rest of the United States. They are worried about what this might mean for the rapid installation rates called for by Law 17-2019. They believe that Puerto Rico will need to attract talent from the mainland to meet its renewable energy goals.
- **Role of gas generation**: Stakeholders see gas as a transitional technology and worry about initial overinvestment in the gas infrastructure.
- **Role of utility-scale PV**: Stakeholders are weary that many utility-scale projects will be developed initially without proper coordination because of the pressures of meeting targets in Law 17-2019. Some stakeholders believe that Puerto Rico is not big enough to handle a lot of utility-scale PV systems and that these will cause grid saturation and limit opportunities for distributed generation. Stakeholders believe that projects at different scales are needed to maintain grid stability and that the environmental impact of large-scale systems should be considered.
- **Battery storage**: There have been high levels of interest to pair PV systems with battery energy storage for resilience benefits after Hurricane María. Stakeholders are concerned that costs for such systems are still prohibitively high for most Puerto Rican income levels and that existing policies (e.g., net energy metering) do not provide incentives for battery owners to operate. Stakeholders suggest access to ancillary services markets or the creation of reactive power tariffs as ways to improve the economics of storage systems.
- **Education**: Stakeholders believe there is a large education gap in Puerto Rico on the topic of advanced inverter functionality. They would like more information on the status of technological developments and what that might mean for power systems operation. Stakeholders would also like more information on the microgrid requirements component of IEEE Std 1547-2018.

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Appendix A. Interconnection Requirements Summary

Appendix A contains a summary of interconnection requirements specified in the Puerto Rico Electric Power Authority (PREPA) Technical Requirements for Interconnecting Distributed Variable Generation (Document 8915,[26] published February 6, 2017). The document was translated from the original Spanish into English by National Renewable Energy Laboratory staff.

[26] Reglamento para interconectar generadores con el sistema de distribución eléctrica de la autoridad de energía eléctrica y participar en los programas de medición neta, PREPA, February 6, 2017

This appendix contains a summary of interconnection requirements specified in the Puerto Rico Electric Power Authority (PREPA) Technical Requirements for Interconnecting Distributed Variable Generation (Document 8915[1], published February 6, 2017). The document was translated from the original Spanish into English by NREL staff.

1. Interconnection regulations for connecting to the distribution network only apply to distributed generation (DG) with a maximum installed capacity of 1 MW-AC or less and projects that are interested in participating in the **basic, aggregate or shared net metering programs.** All DG with a capacity greater than 1 MW must be interconnected to PREPA's transmission or sub-transmission system, at nominal voltages of 115 kV and 38 kV respectively. For a residential customer, the maximum capacity of the DG to be installed is further limited to 25 kW-AC.
2. For projects with synchronous generators, induction generators, or wind turbines, whose protection and control and interconnection equipment are not certified under IEEE Std 1547 and UL 1741, additional evaluation by (OEPPE) and certification through (OGPe) will be required.
3. The interconnection of DG in parallel with the electrical distribution system of PREPA does not grant the client the right to use the client's system for the distribution or sale of energy to other PREPA clients, except for the participants in the shared net metering program, under which energy can be distributed between several customers.
4. If an agreement cannot be reached between the relevant parties within the non-extendable 120-day period, starting from the filing of the interconnection and net metering request to PREPA, except in cases that require supplementary studies for which this term will be extended to 180 days, or in cases where PREPA must disconnect the DG for technical or safety reasons, or in cases where there are disputes over billing or accreditation, PREPA will have jurisdiction over settling all such issues (Law 57-2014).
5. PREPA will create and maintain an updated electronic registration system or database with an inventory of DG systems that are interconnected to the grid. This database will include, for each DG system interconnected, the personal information of the account holder, the location and technical information of the DG system and a description of the electrical infrastructure to which the DG is interconnected. In accordance with the policy of public transparency, PREPA will publish a version of this database on its website with the personal information of the customers deleted.

[1] Reglamento para interconectar generadores con el sistema de distribución eléctrica de la autoridad de energía eléctrica y participar en los programas de medición neta, PREPA, Feb 6 2017

The Expedited Process for Interconnecting DG to the Distribution System

1. The expedited evaluation process is available to customers who intend to interconnect an inverter-based DG system with a capacity of 1 MW or less.
2. There are three options within the Expedited Process: two for systems with a capacity of 10 kW or less and one for those with a capacity of greater than 10 kW up to 1 MW.
3. For the proposed DG project to be evaluated through an expedited process, it must comply with the criteria detailed in Article D (metering) of the interconnection document. If the inverter is not on the list of inverters approved by PREPA for interconnecting to its electrical distribution system, the customer must submit the manufacturer's manual so that PREPA can evaluate and approve the equipment before starting the evaluation of the project through the corresponding expedited process. If the DG system does not meet any other of the criteria, the evaluation of the project will follow the non-expedited process.
4. PREPA maintains a list of feeders that require supplementary study on its website. This list includes the feeders that exceed 15% of their annual peak demand and the areas to which they distribute energy. Any DG project that proposes to connect to a feeder on this list must follow the non-expedited process.
5. The DG system must comply with the following criteria in order to be evaluated under the expedited process:

   The inverter must be certified by OGPe and approved by PREPA. If the inverter is not pre-approved by PREPA, the customer must submit the manufacturer's manual so that PREPA can evaluate whether it is appropriate for interconnecting with the distribution system and add it to the list of approved inverters.

   For single-phase DG, inverter-based technology with an AC capacity of 25 kW or less must be used.

   Three-phase DG with an AC capacity of 200 kW or less are eligible to be evaluated through this process.

   Three-phase DG with a capacity greater than 200 kW up to 1 MW can only be evaluated through this process if it is interconnected using overhead cables of 266 kcmil type ACSR or greater, or underground cables of 500 kcmil type XLPE or greater, from the substation to the point of delivery. Additionally, the length of the feeder must comply with the distance requirements by voltage level as listed in Table 1:

Table 1. Additional criteria for the expedited evaluation process for DG with a capacity of greater than 200 kW up to 1 MW

Line-to-line voltage (kV)	Maximum feeder length from the substation to the point of delivery (mi)
4.16	0.5
4.8	0.5
7.2	1.5
8.32	1.5
13.2	2.0

The aggregate capacity of all DG interconnected to a transformer, including any proposed DG projects, must be less than or equal to the capacity of the transformer.

The maximum aggregated generation capacity to be interconnected on the secondary side of a single-phase transformer or a bank of transformers that supplies more than one customer, must be less than or equal to the capacity of the transformer.

For transformer banks with an open delta connection, the maximum aggregated generation capacity cannot exceed the effective capacity of the transformer, or 87.5% of the nominal capacity.

The aggregate capacity of all DG interconnected in one feeder, including any proposed DG projects, cannot exceed 15% of the annual peak demand of the feeder. This peak demand will be determined at the output of the substation feeder and shall correspond to the maximum demand recorded on the feeder during the twelve months preceding the date on which the evaluation request was received.

The sum of the short-circuit current contributions from all the DG connected to a feeder, including any proposed DG projects, cannot exceed 10% of the maximum short-circuit current limit on the primary side of the feeder.

The DG of the client, in conjunction with the other DG systems interconnected in the feeder, cannot cause any protective equipment or DG of another customer to exceed 87.5% of its capacity to interrupt a short circuit. This includes, among others, substation switches, fuses in the feeder and automatic reclosers.

If the DG of the client is connected to the secondary side of a distribution transformer at 120/240 V that serves more than one client, the DG cannot cause an imbalance greater than 20%.

The installation of the proposed DG system cannot require PREPA to construct new infrastructure.

Expedited Process – DG with a capacity of 10kW or less
A. "Plug and Play" (Expedited Process as ordered by the Commission)

1. This process is only available to customers interested in interconnecting a **rooftop solar photovoltaic system** with a capacity of up to 10 kW on residential and commercial premises, exclusively with equipment and components certified by the OEPPE and found on the lists of solar PV equipment and components available on the website of the Energy Commission of Puerto Rico.

2. Evaluating the project for interconnection:
   2.1. The client must complete and electronically send the evaluation request form to interconnect inverter-based generators with a capacity of 10kW or less to the Distribution Engineering Department of the corresponding region, the OGPe, or the applicable Autonomous Municipality with Hierarchies from I to V.
   2.2. The document must be accompanied by
      - A $100 payment
      - Confirmation of Customer Orientation on the DG Interconnection Process Established by PREPA (form)
      - Evidence that the equipment and components used for interconnection are on PREC's lists and have OGPe certifications, as approved by the OEPPE
      - Illustrative diagram of the DG installation until the point of delivery (POD), including all the components of the proposed DG system, signed and stamped by a licensed engineer
      - Application receipt
      - Statement from the property owner if the client is not the owner of the property where the DG will be installed (form)
   2.3. PREPA will verify the information in the evaluation request and reply with an official receipt of receiving the application within five business days. The date of this receipt will determine the order in which applications are assessed.
   2.4. PREPA will send to the client a letter of endorsement or refusal of the project in no more than ten business days from the date on which all required documents are received. If the customer is interested in participating in one of the net metering programs, this letter will be sent to the customer in less than fifteen business days.
   2.5. Any new project that consists of multiple units, each with one or more DG units and with individual electric service, will be considered for evaluation purposes as a single project (e.g. the development of a project with multiple residential units each with its own DG). The evaluation takes into consideration the characteristics of each individual DG and the overall performance of all the DGs that are part of the project. The associated costs of the study, if any, are the responsibility of the client.
   2.6. The letter of endorsement is valid for one year during which the client must start the construction process. Once started, the client has 18 months to finish the project. If the project cannot be completed a new evaluation request must be submitted.
3. Electrical construction and interconnection test:
   3.1. Construction may begin when PREPA sends a letter endorsing the project.
   3.2. The client or the authorized contractor must notify the Office of Inspections of the region where the DG is installed the date of the acceptance tests at least 10 days in advance of the tests. PREPA reserves the right to attend the tests. PREPA's absence from tests that followed proper notification procedures cannot be the reason for PREPA to ask them to be repeated or in any way delay the operation of the DG system in question.
   3.3. The client or an authorized representative conducts the acceptance tests.
4. Interconnection approval:
   4.1. The client or authorized contractor must electronically submit the following:
      - Certificate of DG System Tests for Interconnection to PREPA's Distribution System

- Evidence that the inverter is able to fulfill the disconnection time requirements for the identified range of voltages and frequencies
- Evidence that the DG installer is certified by the appropriate government agency.
- Evidence of the certification of installation of a PV system from OGPe or a receipt showing the request of OGPe certification.
- Signed Exemption from the General Public Liability Insurance Policy form
- Signed Interconnection Agreement

4.2. The client must submit the Certification of Electrical Installation to the Office of Inspections of the region where the DG is interconnected, guaranteeing the installation followed the specifications in the diagrams and documents previously submitted when requesting interconnection. It must further guarantee the completed construction follows NEC, NESC, applicable laws, regulations, manuals, and technical communication from PREPA and other agencies or government entities. This document must be certified by a licensed electrical engineer or a licensed electrician. If this document is electronically submitted, PREPA will send an electronic receipt to the client or authorized contractor. If submitted in person, the Office of Inspections will sign the Certification of Electrical Installation and return it to the client in no more than 5 business days.

4.3. Once the Certification of Electrical Installation mentioned previously is submitted, the client may interconnect the DG system to PREPA's network.

4.4. In cases where the client has not submitted the OGPe certification for a PV installation, this must be submitted as soon as it is received.

4.5. Once all the previous requirements have been met, it will constitute a formal acceptance of all the terms and conditions between PREPA and the client.

B. Expedited Process for DG Requiring Permission from OGPe or the Autonomous Municipality with Hierarchies from I to V

1. This process is available to customers who are interested in interconnecting an inverter-based system with a capacity of up to 10 kW, **regardless of the energy source** it uses or its location within the client's premises.
2. The client submits the evaluation request to OGPe. Once OGPe evaluates and endorses the plans for DG interconnection, they will refer to PREPA to continue the process. Once PREPA endorses the plans, the client can begin construction.
3. DG that are inverter-based and have a capacity of less than 300 kW are exempt from the General Public Liability Insurance Policy.
4. The client is responsible for hiring a private inspector to verify construction is carried out in accordance with the endorsed plans before operating the DG in parallel with PREPA's electrical distribution system. The private inspector must also certify the Certification of Inspection of Electrical Construction Work.

C. Expedited Process for DG with a Capacity Greater than 10 kW, up to 1 MW

1. The client must complete and electronically send the evaluation request form to the Distribution Engineering Department of the corresponding region, the OGPe, or the applicable Autonomous Municipality with Hierarchies from I to V.

The application should be accompanied by an application fee, the Confirmation of Customer Orientation on the DG Interconnection Process Established by PREPA (form), site plans, illustrative diagrams showing the DG installation up to the point of delivery, OGPe certificates for equipment approved by OEPPE, application receipt, and a notary certified statement from the property owner authorizing the DG installation if the client is not the property owner.

2. Customers with a DG installation with a capacity of 500 kW or more must provide a short-circuit and coordination study with all protection settings and other required information.

The Non-Expedited Process

The non-expedited process is available for any system that does not meet the criteria for the expedited process and/or uses technology that is not inverter-based. These projects require a supplementary study to determine if it is necessary to make improvements to the PREPA's distribution system or changes to the design of the DG system to allow for a secure and reliable DG interconnection.

1. PREPA notifies the client or an authorized representative of the need for a supplemental study and the estimated cost and time involved in the study. The client must accept the supplementary study and associated costs and submit any additional documentation requested within 20 days of being notified or it is understood the client has withdrawn the request.
2. The supplemental study may include a **power flow study, a short-circuit study, a stability assessment study, grounding design verification, and an assessment of the quality of the electrical signal.** The customer can check the status of the supplementary study online.
3. The time it takes to complete the assessment shall be less than or equal to 180 days.

Technical Requirements

Article A – Certificate indicating approval of equipment use

1. By law, all equipment that forms part of a generation system based on renewable energy sources have to be approved by the OEPPE, including but not limited to, photovoltaic modules, wind turbines, synchronous generators, induction generators, inverters and control systems.

- The OEPPE must certify the invertors and control systems that interconnect renewable energy sources with the electrical network comply with the IEEE 1547, UL 1741 and other applicable standards. The list of the equipment and components certified by the OEPPE are available at http://energia.pr.gov.

2. PREPA allows the use of equipment with inverter technology, generators, relays and other devices that meet the applicable standards and codes. These must be evaluated and approved by PREPA.

- PREPA has a list of approved inverters and control systems that is periodically updated. If an inverter or a proposed control system is not on that list, the client must send the manufacturer's manual of the proposed equipment for evaluation in addition to the certification issued by the OGPe showing that it is approved by the OEPPE.

3. If the equipment has not been previously evaluated and approved by PREPA, PREPA may request that the manufacturer, distributor or owner send, a digital file in PDF format, documents certifying the inverter complies with the following:

- Certified by a nationally recognized testing laboratory. This ensures the equipment meets the acceptance criteria for the tests required in the IEEE 1547 or UL 1741 standards, as applicable, for equipment operating continuously in parallel with the electrical system.
- Complies with the permitted harmonic content distortion limits, according to the IEEE 519 and other applicable standards.
- Complies with the voltage flicker limits, according to the IEEE 1453 and other applicable standards.
- Complies with other applicable PREPA regulations. When there are conflicts with other standards, PREPA regulations take precedence.
- Equipment has the ability to operate continuously in parallel (grid-tied) with PREPA's electrical distribution system.
- Equipment has the ability to adjust in the areas of frequency, voltage and operation time.

Article B – Protection & Control

1. Customer's DG must comply with the applicable standards, including but not limited to, the **IEEE 1547, IEEE 519 and IEEE/ANSI C37.90 (Standard for Relays and Relay Systems Associated with Electric Power Apparatus).** In the case of equipment with inverter technology, they must be certified according to the standard **UL 1741.**
2. For DG with capacity of 500 kW or more, PREPA requires that the customer installs a protection relay with microprocessor technology. The scheduled settings for this relay must ensure compliance with applicable standards and requirements, including the IEEE 1547 series of standards. The design of the circuit associated with the relay must include at least the following:
    - Brand, model and characteristics of the protection relay
    - Input connections and outputs from the relay
    - Connections of the current and voltage transformers associated with the protection relay. This equipment must comply with the **ANSI/IEEE C 57.13 standard (Standard Requirements for Instrument Transformers).**
    - Classification and turns ratio of current transformers (CT - current transformer), which must be classified for use in protection systems
    - Turns ratio of voltage transformers (VT - voltage transformer)
    - Voltages on the primary and secondary side of the transformer, maximum and minimum capacity, configuration of the connection of the windings on the primary and secondary side of the transformer and impedance (including the capacity at which it was measured) of the interconnection transformer
    - Rating and speed of the fuse that protects the high voltage side of the interconnection transformer.
    - Use of a dedicated switch that disconnects the DG from electrical disturbances
    - Operating voltage source for the relay, which will ensure activation of this device during electrical disturbances

3. Customers with a DG capacity of 500 kW or more must electronically submit a short-circuit study and another coordination study with all the programmed protection settings including the logical equations of control and the inputs and outputs of the relay.
4. The minimum functions required for protection for the interconnection of DG systems with a capacity of 500 kW or more, which include synchronous generators, induction generators, or wind turbines, with PREPA's electrical distribution system are listed on page 48 of the interconnection document.
5. The minimum functions required for protection for the interconnection of DG systems with a capacity of 500 kW or more, which include technologies with inverters, with PREPA's electrical distribution system are listed on page 48 of the interconnection document.
6. For DG with a capacity of less than 500 kW, PREPA accepts the protection functions integrated in the inverters provided that PREPA has approved of them before and they provide the minimum protection functions required for overvoltage, undervoltage, over frequency, under frequency, and short circuit current.
7. The protection and control system of the DG must be able to detect electrical disturbances that occur on PREPA's electrical system. The DG must disconnect from the distribution circuit as soon as an electrical disturbance occurs, before the first reclosing operation of the circuit protection. Once disconnected from PREPA's distribution system, the DG measures the voltage and the frequency of PREPA's system at the point of interconnection. The DG reconnects once the voltage and frequency remain at suitable levels for at least five minutes. The inverter must be programmed to disconnect the DG system according to the criteria in Tables 2 and 3.
8. The DG must not energize a de-energized circuit. If an electric island situation arises, the DG must be disconnected from PREPA's system in less than two seconds.
9. By order of the Energy Commission, PREPA does not require the installation of an external manual switch for inverter-based DG systems with a capacity of up to 300 kW. However, according to the NEC, all DG installations are required to provide a means of disconnection on the AC voltage side of the inverter. In the case of DG systems with a capacity of greater than 300 kW, an external manual switch is required.

Table 2. Disconnection by voltage variations in the distribution system *

Required programming in the DG		
Voltage Range (% nominal voltage)	**Disconnect time (s)**	**Adjustable disconnect time to a value in seconds of:**
V < 45	0.16	0.16
45 ≤ V < 60	1	11
60 ≤ V < 88	2	21
110 < V < 120	1	13
V ≥ 120	0.16	0.16
* Note: These values must be programmed in the inverter or the protective equipment prior to the testing process of the DG. PREPA may require other disconnection times or voltage ranges as set out in the current IEEE 1547 standard.		

Table 3. Disconnection by frequency variations in the distribution system *

Required programming in the DG		
Function	**Frequency (Hz)**	**Time to Disconnect (s)**
Under Frequency 1	f < 57.5	10
Under Frequency 2	57.5 ≤ f < 59.2	300
Over frequency 1	60.5 < f ≤ 61.5	300
Over frequency 2	f > 61.5	10
* Note: These values must be programmed in the inverter or the protective equipment before the DG test process. PREPA may require other disconnection times or frequency ranges as set in the current IEEE 1547 standard.		

Article C – Power Quality

1. The DG must meet the electrical signal quality requirements specified in IEEE 519, IEEE 1453, IEEE 1159, IEEE 1547, UL 1741 and other applicable standards.
2. The DG interconnection must not cause any power quality degradation, examples include but are not limited to, voltage imbalance and regulation, harmonic distortion, flicker, voltage sags, interruptions, ferroresonance, and transient phenomena.
3. If the DG uses PREPA's system to start, it may not cause voltage drops on the primary side of the interconnection greater than 3%.
4. PREPA can specify the configuration of the windings on the primary and secondary side of a three-phase interconnection transformer to ensure the DG does not degrade power quality.

5. The client is responsible for making the necessary modifications and paying for the cost of the modification to mitigate any problems with power quality.
6. In cases where the DG system includes an induction generator, the client is responsible for providing reactive power compensation at startup to control abrupt voltage changes and avoid discontinuities.
7. The client must make sure voltage and current injections with harmonics do not increase the thermal heating in transformers or reactors. They must also not cause failures, overloading, equipment malfunctions, resonant voltages or other issues to PREPA's network. They must also not interfere with telecommunication or signals systems/circuits.
8. For synchronous generators, induction generators, or wind turbines whose protection and control systems have equipment or devices that are not certified under IEEE1547 or UL1741, the client is responsible for carrying out the power quality studies (harmonic distortion, voltage imbalance, voltage flicker, etc.) at the point of interconnection of the DG and the point of delivery of energy to PREPA. During the process of inspecting the project, the client must submit reports of these studies, certifying the DG complies with IEEE1547, IEEE519 and other applicable standards from the electrical industry.
9. For DG with capacity from 500 kW to 1 MW, PREPA may require reliability studies.

Article D – Metering

The DG interconnects with the distribution system through PREPA's metering equipment on the client's installations. The existing meter must be reconfigured or replaced to allow bidirectional flows and historical load profiles. PREPA will replace or reconfigure the meter within 20 business days from the date of the endorsement letter. PREPA is responsible for maintaining all meters, CTs, and VTs, reserving the right to modify metering requirements based on future operational needs.

The minimum required characteristics of the meter that PREPA installs for customers who interconnect DG with PREPA's electrical distribution system are as follows:

- For customers connected to the secondary distribution voltage level:
    - Be fully electronic (solid state electronic meter)
    - Have bi-directional measurements with separate readings of energy received and energy delivered
    - Have memory capacity to record consumption at one-hour intervals with a minimum of two channels of memory, kWh delivered and kWh received
    - Be able to communicate through PREPA's remote metering system
- For customers connected to the primary distribution voltage level:
    - Energized through CT and VT with a precision rating for metering (metering accuracy class)
    - Be fully electronic (solid state electronic meter)
    - Have four quadrant metering capabilities, measuring real and reactive power, received and delivered
    - Have memory capacity to record a minimum of sixty days of consumption in fifteen-minute intervals, with a minimum of seven memory channels: kWh delivered, kVARh delivered, kWh received, kVARh received, and squared volts hour for the three phases

- Be able to communicate through PREPA's remote metering system

Net Metering Programs

Clients requesting to interconnect a renewable energy-based DG system have the option of participating in one of three net metering programs: Basic Net Metering, Aggregate Net Metering, and Shared Net Metering. Request to participate in net metering is submitted with the application for DG interconnection.

- **Basic Net Metering Program**
  - DG units must have a maximum installed capacity of 25 kW-AC for residential customers and 1 MW for commercial, governmental, industrial, agricultural customers, educational institutions, and medical facilities
- **Aggregate Net Metering Program**
  - The aggregate net metering program is only for government entities and non-profit university institutions.
  - For clients with service at the distribution voltage, the maximum installed capacity of the DG is limited to 1 MW-AC.
  - All service agreements accepted into this program must be included under the same account.
  - All of the properties must have electricity service at the same voltage level according to the client's tariff, which may be secondary or primary distribution.
  - All of the client's properties that will receive energy credits must be in the same location as the installed DG system or where there are interconnections to the same electrical line at a distance of no more than 2 miles from the DG installation.
  - The agreement for interconnecting a DG system and participating in this program will be effective 30 days after the first tariff revision comes into effect (established in Law 57).
- **Shared Net Metering Program**
  - The shared net metering program applies exclusively to residential and commercial customers with voltage service at the primary or secondary distribution level, and who are under a horizontal property regime (e.g. residential, commercial or mixed-use condominiums). This program also applies to public housing managed through the Department of Housing.
  - The properties of the clients receiving the energy credits must be located where the DG system is installed.
  - All properties must be receiving electricity service at the same voltage level and from the same point of delivery in PREPA's network as where the DG is interconnected. The point of delivery can be the interconnection transformer in secondary distribution systems or a private substation in primary distribution systems.
  - In residential cases, the maximum capacity of the DG system is 25kW for each participating client or up to the capacity of the interconnection transformer for a maximum of 1 MW.
  - In commercial or mixed-use cases, the maximum capacity of the DG system is equal to the capacity of the interconnection transformer up to a maximum of 1 MW.

- The owner of the DG system must sign an agreement for interconnecting to PREPA's distribution and the net metering agreement. All other participating clients who are not the owner of the DG system must sign the agreement for participating in the shared net metering program.
- The agreement for interconnecting a DG system and participating in this program will be effective 30 days after the first tariff revision comes into effect (established in Law 57).

Energy Compensation for Customers Participating in a Net Metering Program

1. Energy compensation begins at the start of the first billing period after the installation or configuration of the meter.
2. For every billing period, PREPA measures the amount of energy consumed and exported by the client.
3. If during the billing period, PREPA supplies the customer with more energy than the customer exports, the customer will be charged for his net consumption.
4. If during the billing period, the customer exports more energy than PREPA supplies, the customer will be charged the minimum fee corresponding to the rate tariff. The minimum fee is the amount PREPA charges a customer who does not consume electricity during a billing period. **PREPA will credit the customer for excess energy during the billing period up to a maximum daily value of 300 kWh for residential customers and 10 MWh for commercial clients.** The energy export credit will be applied to the client's invoice at the next billing period.
5. Any energy export credit the client accumulates during the previous year that has not been used by the end of the billing period in June of each year, will be credited in the following ways:
    a. PREPA will use the largest of the following quantities: **10₵/kWh** or the amount that results from subtracting the price that PREPA charges its clients, converted into cents per kilowatt hour, the charge for adjustment, for the purchase of energy and fuel.
    b. **PREPA will buy 75% of the surplus from the client and credit 25% to the electricity bill of the Department of Education.**
6. For clients participating in the Aggregate Net Metering Program, in addition to the provisions above, the following applies:
    a. Properties located in the same place - The maximum amount of energy to be credited to all service agreements within the location where the DG is located is equal to 100% of the consumption of the properties at the location. This energy is first credited to the service agreement associated with the DG installation and the excess is equitably credited among the rest of the service agreements in the same account.
    b. Properties located in different places - The maximum amount of energy to be credited to all service agreements is equal to 120% of the consumption of the properties at the location where the DG is located. Of this 120%, 100% will be credited towards the properties where the DG is located and the remaining 20% will be equitably credited to the service agreements in the other locations that are in the same account.

7. For customers participating in the Shared Net Metering, in addition to provisions 1-5 above, 100% of the energy produced by the DG system will be equitably credited among all the participants of this program.

Appendix B. Interconnection Flowcharts and Process Maps

As of this writing, the most current publicly available interconnection process flowchart is a pre-Hurricane Maria vintage; yet when PREPA updated its written rule (2017), an updated process flowchart was not published. To analyze the prevailing procedure, the National Renewable Energy Laboratory updated the older flowchart to the current rule and developed swim-lane charts to analyze responsibility handoffs. Note that during final review of this report, the project team learned that PREPA has prepared a revised set of simplified flowcharts that correspond with the updated rule. The revised flowcharts have been presented to internal and external audiences but not been published yet. These are attached as Appendix C to this report.

As of this writing, the most current interconnection process flowchart is a pre-Hurricane Maria vintage. Yet, when PREPA updated its written rule (2017), an updated process flowchart was not included.

To analyze the prevailing procedure, the National Renewable Energy Laboratory translated this older flowchart into English and updated it to the current rule. This diagram was shared with stakeholders in Puerto Rico for review and comment.

Interconnection Flowchart

To facilitate analysis and discussion, an audit diagram technique was implemented, and each process step was numbered for reference. At every decision block, steps with a positive decision outflow were numbered in whole numbers, whereas steps corresponding to a negative decision (i.e. “No”) outflow were tracked through progressive levels of decimal digits.

The audit diagram approach of numerical labeling may be used to support performance management. This schema is particularly useful for performance managers and quality auditors in the identification and elimination of bottlenecks because it facilitates the identification of procedure steps that hold the largest in-process procedure queues (i.e. backlog).

To further promote analysis and process management, NREL organized the flowchart into five distinct phases which are detailed in the main body of the report (see section 5.1 Process Analysis for Distributed Energy Resource Interconnection) and summarized in the figure below.

Figure 1. Overview of the DER interconnection process


Phases of DER Interconnection Process
Phase 1- Interconnection Application
1
The client sends the following documents to the Distribution Engineering Department of the region where the DG system is to be installed, the OGPe, or the applicable Autonomous Municipality with Hierarchies from I to V:
• Forms: "Evaluation Request for Interconnecting Generators to the Electrical Distribution System," "Confirmation of Client Orientation over the Established PREPA Process for the Interconnection of DG," and "Affidavit of the Property Owner(s)" (to authorize the DG installation if the client does not own the property where the DG system will be installed; this document must be notarized)
• Application fee
• Evidence the equipment and components used for interconnection are on PREB's pre-approved list of equipment with OGPe certification, or direct OGPe certificates showing the equipment is approved by the OEPPE
• Illustrative diagram of the DG installation until the point of delivery, including all the components of the proposed DG system, signed and stamped by a licensed engineer
• Site plans, with project locations in Lambert state plane coordinates, if the proposed system size is greater than 10kW or not inverter-based
• Manufacturer's manual of the interconnection equipment if the system is not inverter-based
• Application receipt (if the portal is unavailable)
These documents are submitted through the online portal. If the portal is unavailable, the client can complete the PDF forms found on PREPA's website.
2
The Distribution Engineering Department verifies the information in the interconnection request: Does the project fall under the Expedited Interconnection Process?
Yes
No
3
PREPA sends the client an official receipt of the interconnection request within 5 business days. The date of this receipt determines the order in which requests are evaluated.
PREPA also sends the client a letter with the results of the evaluation within 10 business days (15 if the client is interested in participating in net metering). This letter of project endorsement is valid for one year, during which the client must start the construction process or a new interconnection request must be submitted.
2.1
PREPA sends the client an official receipt of the interconnection request within 5 business days. The date of this receipt determines the order in which requests are evaluated.
PREPA sends a letter to the client indicating the proposed DG connection requires a supplementary study along with the estimated cost and time of the study within 10 business days.
All supplementary studies are conducted in San Juan and may include a power flow, short circuit, and stability study, grounding design verification, and power quality assessment.
4
Is the proposed system rooftop PV ≤ 10kW?
No
4.1
Is the proposed system another technology ≤ 10kW?
No
4.1.1.
Is the proposed System > 10 kW and ≤ 1 MW?
No
Process ends
Yes
Yes
Yes
2.2
The client has 20 calendar days to,
• Pay the cost of the supplementary study. If the client does not pay within this time frame, it is understood that the client withdraws the DG evaluation request.
• Submit any additional requested information.
• Request a meeting to discuss and clarify the preliminary results of the evaluation and the analyses required for the supplementary study.
2.3
Does the client agree to proceed with the study?
Yes
No
Process ends
4.1.2
The client submits the following to the Distribution Engineering Department of the region where the DG system is to be installed, for plan endorsement:
• Evidence that the client has the right to install DG on the property if the client is not the property owner (if this documentation has not been presented earlier in the process)
• Electrical installation plans digitally signed by the designer on each page
• The "Certification of Electrical Installation Plans" form digitally signed by the designer
• Evidence the designer is a licensed engineer
• Diagrams showing the proposed protection and control scheme following the protection and control requirements established in the interconnection regulations document
The designer must guarantee project plans are in accordance with NEC, NESC, and laws, regulations, manuals, standards, and technical communications approved by PREPA.
2.4
PREPA begins the study as soon as payment is received. The goal of the study is to determine the impact of the DG system on the distribution network, and identify any necessary improvements to the DG system design or the client's/PREPA's other electrical installations to minimize or eliminate the impact of the DG system.
2.5
The client can check the progress of the supplementary study via the online portal.
2.6
PREPA sends the client a letter with the results and recommendations of the study to sign within 180 days. If the supplementary study reveals that changes to PREPA's distribution system equipment or to the design of the DG system are necessary, the client must make and pay for the required changes. Supplementary study results are valid for one year.
2.7
Does the client accept the results of the study?
Yes
No
4.1.3
The Distribution Engineering Department of the corresponding region evaluates the project plans within 5 business days and notifies the client.
4.1.4.2
The designer makes changes and resubmits new plans.
4.1.4
Does the Distribution Engineering Department of the corresponding region endorse the project plans?
No
4.1.4.1
The Distribution Engineering Department of the corresponding region informs the client's contracted designer of comments about the design.
4.2
The client or an authorized representative must follow the process established in the Joint Regulations document with the OGPe.
4.1.5
The endorsed project plans are valid for 2 years.
4.3
Once the OGPe receives the evaluation request and endorses the DG interconnection plans, it will pass the documents on to PREPA for additional evaluation.
4.1.6
Is the proposed system ≤ 500 kW?
No
4.1.6.1
The client must electronically submit a short circuit study plan and a coordination study plan with all the protection settings as detailed in the interconnection regulations document.
4.1.6.2
PREPA evaluates and approves the short circuit and coordination study plans within 10 business days and notifies the client to perform the tests.
4.4
PREPA evaluates the DG interconnection and endorses the design plans in accordance with the technical requirements in the interconnection regulations document within the timelines established in the Joint Regulations document with the OGPe.
Yes
4.1.6.3
The client performs the tests on the relays at the approved settings and submits the results electronically, digitally signed by a licensed electrical engineer.
4.1.6.4
PREPA schedules an inspection of the DG system within five business days of approving the results of the relay tests.
Phase 2- Construction and Testing
4.5
The client or the client's contractor must electronically notify the Office of Inspections of the region where the DG system is to be installed, the start of construction. If the portal is unavailable, the appropriate form can be found on PREPA's website.
5
The client (or an authorized representative):
• Installs the DG system. Construction may begin as soon as the endorsement letter from PREPA and permits and endorsements from other agencies, if applicable, are received. Once started, the client has 18 months to finish the project or a new evaluation request must be submitted.
• Notifies the Office of Inspections of the region where the DG system is installed at least 10 business days before conducting acceptance tests. If the portal is unavailable, the appropriate form for notification can be found on PREPA's website.
6
PREPA reserves the right to be present at the acceptance tests. However, PREPA's absence, if given sufficient notice, cannot cause PREPA to ask for the tests be repeated or otherwise interrupt, delay or stop the operation of the DG system.
7
The client (or an authorized representative):
• Conducts the required acceptance tests specified in the interconnection regulations document.
• Submits the following documents electronically:
○ "Certification of Tests for Distributed Generation Systems Interconnecting to PREPA's Electrical Distribution System." This document must be digitally signed by a licensed electrical engineer.
○ Evidence that disconnection times for the inverter at different voltage and frequency ranges comply with the values specified in the interconnection regulations document (e.g. a print screen of the inverter programming, or certification from the inverter manufacturer).
○ Evidence the DG installer is certified by the appropriate government agency.
○ Certification of installation of the photovoltaic system (or any other DG system) issued by the OGPe. If OGPe certificates are not available, the client must submit evidence that such certification was requested from the OGPe and include the payment receipt of that request; the actual certificate must then be submitted as soon as it is received.
○ "Certificate of Public Liability Insurance" or "Exemption from Insurance Requirement" in the case of inverter-based systems under 300 kW (if public liability insurance is required, it must be submitted at least 30 days before the signing of the interconnection agreement).
○ Signed Interconnection Agreement
○ "Certification of Electrical Installation." This document is sent to the Office of Inspections, guaranteeing the installation followed the specifications in the diagrams and documents previously submitted when requesting interconnection. It must further guarantee the completed construction follows NEC, NESC, applicable laws, regulations, manuals, and technical communication from PREPA and other agencies or government entities. This document must be certified by a licensed electrical engineer or a licensed electrician.
Phase 3 – Inspection
8
Is the proposed system rooftop PV ≤ 10kW?
No
8.1
The client is responsible for hiring a private inspector to verify construction is carried out in accordance with the endorsed plans before the DG system can be approved to operate in parallel with PREPA's distribution system.
The form "Certification of Inspection of Electrical Construction Work" must be certified by the private inspector and electronically submitted.
8.2
Is the proposed system another technology ≤ 10kW?
No
8.2.1
Is a power quality study required?
No
Yes
Yes
Yes
8.3
The Office of Inspections signs and accepts the "Certification of Electrical Installation" within 5 business days and sends the client a copy.
8.2.2
The client or an authorized representative must electronically submit the results of the studies done at the point of interconnection and the point of energy delivery to PREPA and certify the quality of the electrical signal complies with standards IEEE 1547, IEEE 519 and other applicable industry standards.
8.4
PREPA verifies the client has provided all the necessary documents for the inspection stage of the project within 5 business days.
Once all the requirements established in the interconnection regulations document are met and the client has submitted the Usage Permit from the OGPe, PREPA approves the interconnection of the DG system within 5 business days.
8.2.3
The Department of Inspections of the corresponding region inspects the project in conjunction with the client's contractor on or before the day of the DG acceptance tests.
8.2.4.2
The client corrects any project irregularities and notifies the Department of Inspections of the corresponding region.
8.2.5
The Office of Inspections signs and accepts the "Certification of Electrical Installation" within 3 business days and sends the client a copy.
Yes
8.2.4
Did the project pass the acceptance tests and inspection?
No
8.2.4.1
The Department of Inspections of the corresponding region sends a written notification to the client regarding any irregularities found in the project within 5 business days. The project cannot be approved until all irregularities have been corrected.
Phase 4 - Interconnection
9
Once the "Certification of Electrical Installation" form is submitted, the client may interconnect the new DG system to PREPA's electrical network.
10
The Office of Inspections signs and accepts the "Certification of Electrical Installation" within 5 business days and sends the client a copy.
11
The Distribution Engineering Department of the corresponding region signs the Interconnection Agreement, and the Exemption from Insurance Requirement agreement if applicable, and sends copies to the client and to the manager of the corresponding Commercial Office or Department of Wholesale Electricity to notify them of meter changes.
Once all the requirements have been met, the client's signature on the Interconnection Agreement constitutes the formal acceptance of the terms and conditions of the contract between the client and PREPA. PREPA reserves the right to perform physically inspections of the DG system in the future, given coordination with the client, to verify the system has not been modified without authorization.
12
The corresponding Commercial Office or Metering Office exchanges the client's meter for a bidirectional meter. This new meter will be able to distinguish and measure the energy PREPA supplies to the client and the energy generated by the client's system that is exported to PREPA's distribution network.
Phase 5 - System Energization
13
Is the client interested in participating in a net metering program?
No
Process ends
Yes
14
If the client account is residential or secondary commercial, the client should go to the Commercial Office with the letter approving interconnection and participation in the net metering program to sign the Net Metering Agreement. If the account is wholesale, the Net Metering Agreement is signed at the Department of Wholesale Electricity in Santurce.
15
The manager of the Commercial office or the Department of Wholesale Electricity signs the Net Metering Agreement and sends the client a signed copy. This document will indicate the start date for participation in the net metering program.

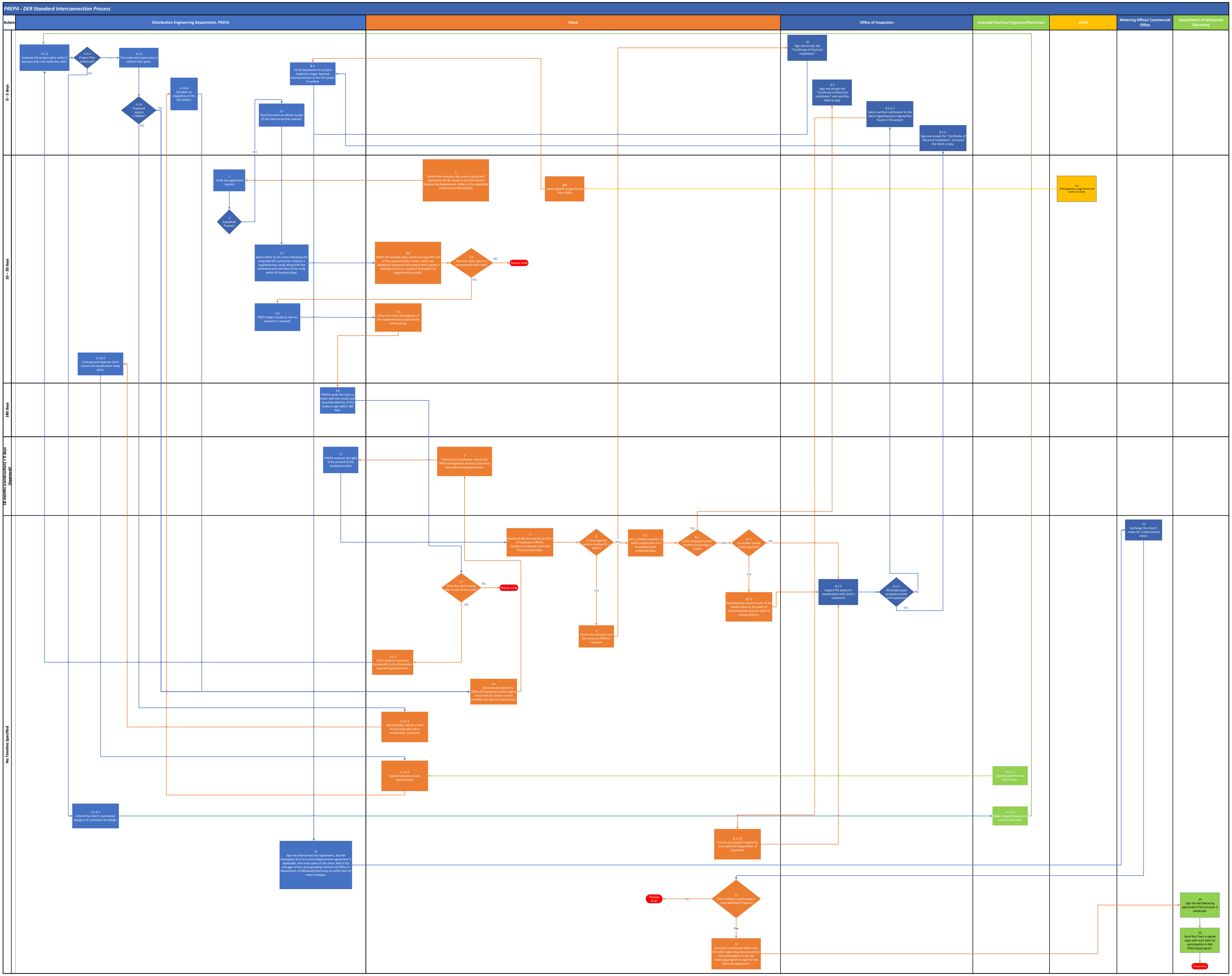
Interconnection Process Maps

The functional flowchart was extended into a set of process maps for easy visualization of each step, categorized primarily by the actor responsible for undertaking the action (entities involved in the process flow, such as client, distribution engineering department, etc.) and the time constraint for each activity.

Defining process boundaries at the point of exchange or hand-off of responsibility is called "swim-lane" diagramming. Swim lanes can serve to clarify process ownership and responsibilities, duplication of efforts, and potentially locate bottlenecks and process delays. Swim lanes can allow the process analyst to identify limited or no value-added exchanges or duplications of effort, which are opportunities to streamline processes.

The process was further subdivided into the **expedited process flow** and the **standard process flow** based on the requirement for conducting supplementary studies.

PREPA - DER Expedited Interconnection Process
Actors
Distribution Engineering Department, PREPA
Client
Office of Inspection
Licensed Electrical Engineer/Electrician
OGPe
Metering Office/ Commercial Office
Department of Wholesale Electricity
0 - 5 days
10 – 20 days
18 months (construction) + 5 days (Approval)
No Timeline Specified
4.1.3 Evaluate the project plans within 5 business days and notify the client.
4.1.4 Project Plan endorsed?
Yes
NO
4.1.5 The endorsed project plan is valid for two years.
4.1.6 Proposed system ≤ 500kW?
Yes
NO
4.1.6.4 Schedule an inspection of the DG system.
8.4. Verify documents for project inspection stage. Approve interconnection of the DG system if verified.
3 Send the client an official receipt of the interconnection request.
10 Sign and accept the "Certificate of Electrical Installation"
8.3 Sign and accept the "Certificate of Electrical Installation" and send the client a copy
8.2.4.1 Send a written notification to the client regarding any irregularities found in the project
8.2.5. Sign and accept the "Certificate of Electrical Installation" and send the client a copy.
1 Submit the necessary documents along with application fee & receipt to the Distribution Engineering Department, OGPe, or the applicable Autonomous Municipality
2 Verify the application request
YES
2 Expedited Process?
3 Send endorsement letter to client with the results of evaluation.
4.1.6.2 Evaluate and Approve short circuit and coordination study plans.
6 PREPA reserves the right to be present at the acceptance tests
5 Client starts installation. Notify the Office of Inspection at least 10 business days before acceptance tests.
Yes
4 System is a rooftop PV and ≤ 10kW?
No
4.1.2 Client submits necessary documents to the Distribution Engineering Department.
Yes
4.1.1. Is the proposed System ≥ 10 kW and ≤ 1 MW?
No
4.1 System is another tech ≤ 10kW
YES
4.2 Follow the process established in the Joint Regulations document with the OGPe.
7 Submit all the documents to Office of Inspection, PREPA. Conduct acceptance tests with licensed electrician.
8 Is the proposed system rooftop PV ≤ 10kW?
NO
Yes
9 Client interconnects new DG system to PREPA's network
8.1. Hire a private inspector to verify construction is in accordance with endorsed plans
YES
8.2. Is the proposed system another technology ≤ 10kW?
NO
8.2.1 Is a power quality study required?
NO
YES
8.2.2 Electronically submit results of the studies done at the point of interconnection and the point of energy delivery.
8.2.3 Inspect the project in coordination with client's contractor
8.2.4. Did project pass acceptance tests and inspection?
NO
YES
12 Exchange the client's meter for a bidirectional meter.
4.3 Receive and endorse the DG interconnection plan. Pass the documents to PREPA for additional evaluation.
4.4 Evaluate the DG interconnection and endorse design plans in accordance with technical requirements.
4.5 Electronically notify the Office of Inspections of the region where the DG system is to be installed, the start of construction.
4.1.6.1 Electronically submit a short circuit study plan and a coordination study plan
4.1.6.3 Submit relay test results electronically.
4.1.5.3 Digitally sign the relay test results.
4.1.4.1 Inform the client's contracted designer of comments on design.
4.1.3.2 Make design changes and submit new plans
8.2.4.2 Correct any project irregularity and notify the Department of Inspection.
11 Sign the Interconnection Agreement, and the Exemption from Insurance Requirement agreement if applicable, and send copies to the client and to the manager of the corresponding Commercial Office or Department of Wholesale Electricity to notify them of meter changes.
Process Ends
No
13 Client willing to participate in a Net Metering Program?
Yes
14 Go to the Commercial Office with the letter approving interconnection and participation in the net metering program to sign the Net Metering Agreement.
14 Sign the Net Metering agreement if the account is wholesale.
15 Send the Client a signed copy with start date for participation in Net Metering program.
Process Ends


PREPA - DER Standard Interconnection Process
Actors
Distribution Engineering Department, PREPA
Client
Office of Inspection
Licensed Electrical Engineer/Electrician
OGPe
Metering Office/ Commercial Office
Department of Wholesale Electricity
0 - 5 days
10 – 20 days
180 days
18 months (construction) + 5 days (Approval)
No Timeline Specified
4.1.3 Evaluate the project plans within 5 business days and notify the client.
4.1.4 Project Plan endorsed?
Yes
NO
4.1.5 The endorsed project plan is valid for two years.
4.1.6 Proposed system ≤ 500kW?
Yes
NO
4.1.6.4 Schedule an inspection of the DG system.
8.4. Verify documents for project inspection stage. Approve interconnection of the DG system if verified.
2.1 Send the client an official receipt of the interconnection request.
NO
2 Verify the application request
2 Expedited Process?
2.1 Send a letter to the client indicating the proposed DG connection requires a supplementary study along with the estimated cost and time of the study within 10 business days.
1 Submit the necessary documents along with application fee & receipt to the Distribution Engineering Department, OGPe, or the applicable Autonomous Municipality
8.4 Client submits Usage Permit from OGPe
2.2 Within 20 calendar days, client must pay the cost of the supplementary study, submit any additional requested information and request a meeting to discuss results of evaluation for supplementary study.
2.3 Does the client agree to proceed with the study?
NO
Process Ends
YES
2.4 PREPA begins study as soon as payment is received.
2.5 Client can check the progress of the supplementary study via the online portal.
4.1.6.2 Evaluate and Approve short circuit and coordination study plans.
2.6 PREPA sends the client a letter with the results and recommendations of the study to sign within 180 days.
6 PREPA reserves the right to be present at the acceptance tests
5 Client starts installation. Notify the Office of Inspection at least 10 business days before acceptance tests.
10 Sign and accept the "Certificate of Electrical Installation"
8.3 Sign and accept the "Certificate of Electrical Installation" and send the client a copy
8.2.4.1 Send a written notification to the client regarding any irregularities found in the project
8.2.5. Sign and accept the "Certificate of Electrical Installation" and send the client a copy.
8.4 OGPe approves Usage Permit and sends it to client.
7 Submit all the documents to Office of Inspection, PREPA. Conduct acceptance tests with licensed electrician.
8 Is the proposed system rooftop PV ≤ 10kW?
NO
YES
8.1. Hire a private inspector to verify construction is in accordance with endorsed plans
8.2. Is the proposed system another technology ≤ 10kW?
YES
NO
8.2.1 Is a power quality study required?
NO
YES
8.2.2 Electronically submit results of the studies done at the point of interconnection and the point of energy delivery.
8.2.3 Inspect the project in coordination with client's contractor
8.2.4. Did project pass acceptance tests and inspection?
NO
YES
9 Client interconnects new DG system to PREPA's network
12 Exchange the client's meter for a bidirectional meter.
2.7 Does the client accept the results of the study?
NO
Process Ends
YES
4.1.2 Client submits necessary documents to the Distribution Engineering Department.
4.5 Electronically notify the Office of Inspections of the region where the DG system is to be installed, the start of construction.
4.1.6.1 Electronically submit a short circuit study plan and a coordination study plan
4.1.6.3 Submit relay test results electronically.
4.1.5.3 Digitally sign the relay test results.
4.1.4.1 Inform the client's contracted designer of comments on design.
4.1.3.2 Make design changes and submit new plans
8.2.4.2 Correct any project irregularity and notify the Department of Inspection.
11 Sign the Interconnection Agreement, and the Exemption from Insurance Requirement agreement if applicable, and send copies to the client and to the manager of the corresponding Commercial Office or Department of Wholesale Electricity to notify them of meter changes.
13 Client willing to participate in a Net Metering Program?
No
Process Ends
Yes
14 Go to the Commercial Office with the letter approving interconnection and participation in the net metering program to sign the Net Metering Agreement.
14 Sign the Net Metering agreement if the account is wholesale.
15 Send the Client a signed copy with start date for participation in Net Metering program.
Process Ends

Appendix C. Simplified Interconnection Flowcharts Prepared by PREPA

PREPA prepared these flowcharts for presentations to explain the DG interconnection process within PREPA. These flowcharts have been shown to the general public but are not previously published.

1. The first diagram shows the interconnection process for DG systems with capacities below 10 kW, as established in the current regulation. IMPORTANT – as of this writing, this process is being modified in order to comply with Act 17-2019 for the interconnection of DG systems with capacities up to 25 kW.

2. The second flow chart shows how the Study Process is dealt internally to PREPA, as established in the current regulation.

3. The third flow chart shows how the Endorsement Process is dealt internally to PREPA, as established in the current regulation.

4. The last flow chart shows how the Inspection Process is dealt internally to PREPA, as established in the current regulation.

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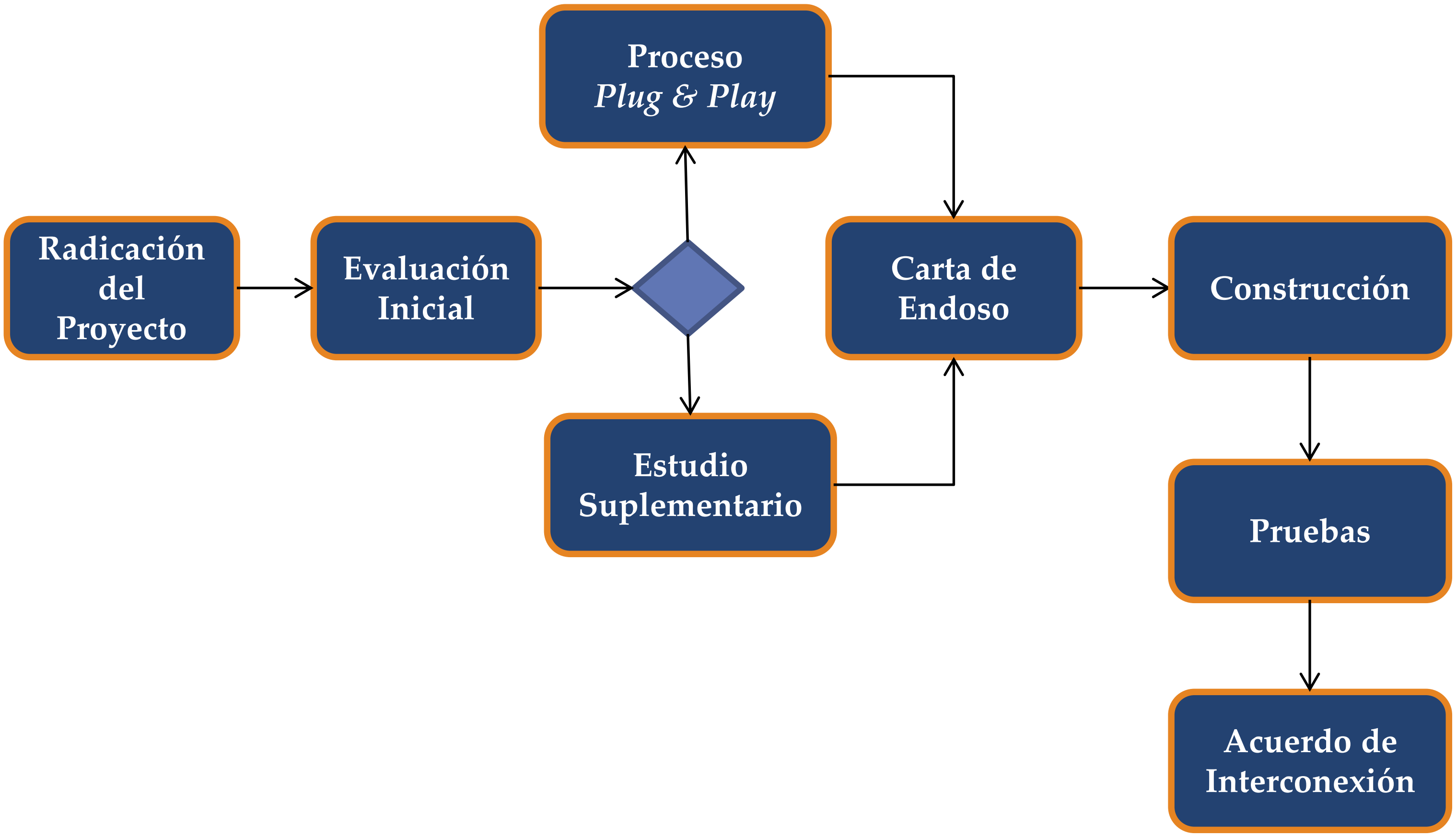
Proceso para GD de 10 kW o menos



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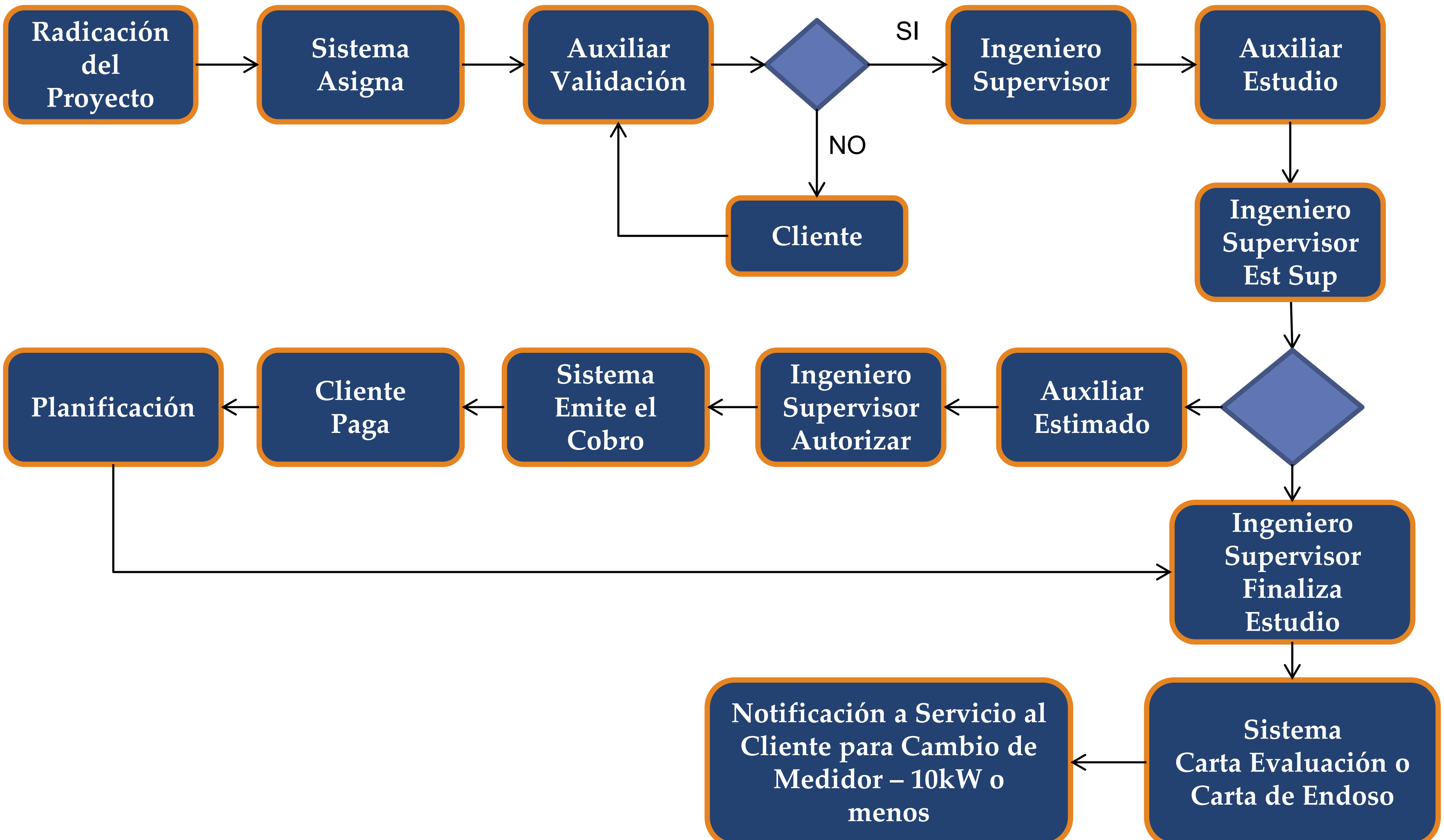
PREPAEE - Estudio



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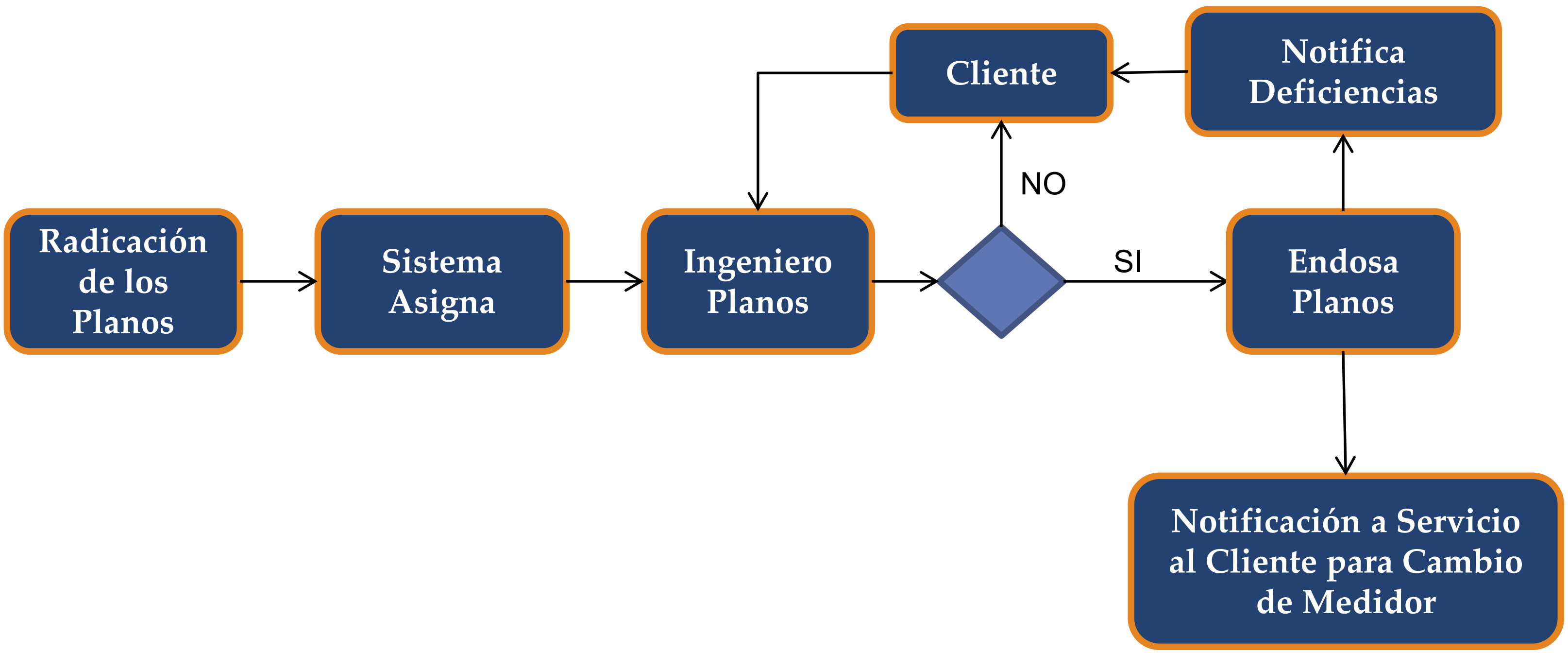
PREPAEE - Endoso



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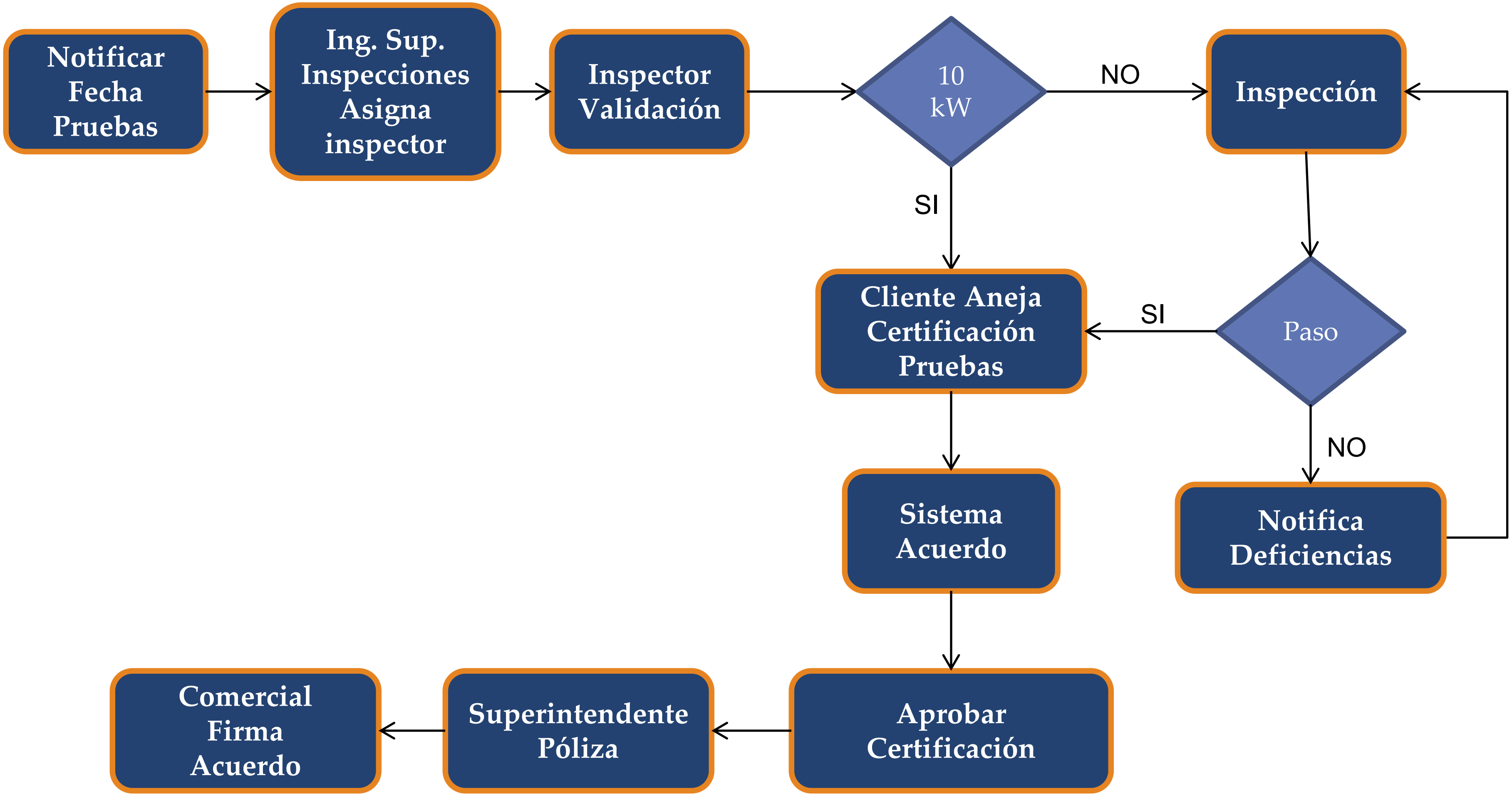
PREPAEE - Inspección



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