Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study (PR100)

Final Report

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Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study (PR100): Final Report

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NOTICE

This work was authored by Argonne National Laboratory (ANL), Lawrence Berkeley National Laboratory (LBNL), National Renewable Energy Laboratory (NREL), Oak Ridge National Laboratory (ORNL), Pacific Northwest National Laboratory (PNNL), and Sandia National Laboratories for the U.S. Department of Energy (DOE) under Contract No. HSFE02-20-IRWA-0011. Funding was provided by the Federal Emergency Management Agency (FEMA) and performed under the technical management of DOE's Grid Deployment Office. The views expressed herein do not necessarily represent the views of DOE, FEMA, or the U.S. Government. The U.S. Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for U.S. Government purposes.

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Some material in this final report has been previously reported in interim publications, and some previously reported material in interim publications was preliminary. This report updates and supersedes previously reported material.

Cover photo by Joe DelNero, NREL 84662.

How to Read this Report and Access Data

This report is organized into sections that mostly align with the tasks that comprise the study. Each section begins with a Summary describing the activities and components of that task or topic; Key Findings in bulleted format; and Considerations describing important qualifications and nuances pertaining to that section. We suggest starting with the Executive Summary, and then reviewing section summaries to identify sections of interest for further reading. One of the principles of the study was to employ open-source models and make data outputs as publicly available as possible. A table of the models and tools employed in the study can be found in Appendix F (page 685), and instructions on how to access the data are below.

Report Overview

Following the introduction in Section 1, in Section 2 we describe our approach to stakeholder engagement to ensure the study process and results were reflective of stakeholder experiences and priorities and it produced results that would be useful. In Section 3, we discuss how we grounded the study in principles and practices of energy justice and worked with the project team to address the topic throughout. In Sections 4 and 5, we present results of data gathering and generation in the form of resources assessments, land availability, and projections for energy efficiency, electric load, and DER adoption. Section 6 discusses the scenarios on which the study was centered, and Sections 7, 8, and 9 present results of capacity expansion, resource adequacy, and production cost modeling of the scenarios. In Sections 10, 11, and 12, we discuss results of analysis of the impacts of scenario results on the bulk power system, the distribution system, and the economy in terms of jobs, macroeconomics, and retail rates. Section 13 presents results from a downscaled climate simulation and climate risk assessment for Puerto Rico, indicating how the archipelago might be affected by a changing climate. Section 14 describes infrastructure interdependency analysis, and social burden analysis to evaluate community-level resilience. In Section 15, we discuss uncertainties inherent in this study, and in Section 16, we discuss future work. Section 17 is the Implementation Roadmap that summarizes key implementation actions by time frame.

How to Access the Data

PR100 final results include publicly available datasets for the following topics:

- Resource Assessment
- Electric Load
- Distributed Solar Photovoltaics (PV) and Storage Investments Over Time
- Integrated Capacity Investment
- Economic Impact Analysis
- Climate and Climate Risk
- Social Burden Analysis

Some of the PR100 final results would reveal proprietary and/or restricted third-party data that cannot be made publicly available via the website or data repository. These topics include:

- Bulk System Power Flow, Dynamic, and Resilience Impact Analysis
- Distribution Grid Impacts.

There are two primary options for accessing and downloading the publicly accessible data:

1. PR100 Website
   - Go to the PR100 Results page (https://pr100.gov/results).
   - Select one of the results topics.
   - Select "Download."
2. PR100 Data Repository
   - Go to the PR100 data repository (https://data.openei.org/submissions/5749).
   - View all available data.
   - Select dataset to start download.

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Although we sought input from these stakeholders throughout the study, the design, assumptions, inputs, methods, and results of PR100 were ultimately determined by the national laboratories conducting the study with guidance from DOE. Because members of the Steering Committee and Advisory Group hold diverse perspectives and priorities, being listed as a group member or study reviewer does not imply agreement with or endorsement of the material presented in this report.

Members of these groups are listed as follows, along with their affiliations. Not all members participated for the full duration of the study. The list includes all members of these groups throughout the study, and their affiliations at the end of their participation.Asterisks denote those who reviewed the final report, for which we are deeply grateful:

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List of Abbreviations and Acronyms

ADDA	Argonne Downscaled Data Archive
AEO	Annual Energy Outlook
AEP	annual energy production
AGC	automatic generation control
AMI	area median income
ASSET	Automated System-wide Strength Evaluation Tool
ATB	Annual Technology Baseline
AWS	Amazon Web Services
BESS	battery energy storage system(s)
BIPOC	Black, Indigenous, and people of color
CapEx	capital expenditure
CBG	census block group
CDBG-DR	Community Development Block Grant Disaster Recovery
CDC	Centers for Disease Control and Prevention
CDD	cooling degree day
CEJST	Climate and Economic Justice Screening Tool
CGE	computable general equilibrium (model)
CHoLES	customer hours of lost electricity service
CJEST	Climate and Economic Justice Screening Tool
CONUS	contiguous United States
C-PAGE	Chronological AC Power Flow Automated Generation tool
CRF	cost recovery factor
DF	debt fraction
DER	distributed energy resource
DNI	direct normal irradiance
DOE	U.S. Department of Energy
DPV	distributed photovoltaics
ECMWF	European Centre for Medium-Range Weather Forecasts
EGRASS	Electrical Grid Resilience and Assessment System
EIA	U.S. Energy Information Administration
EMT	electromagnetic transient
EOL	end of life
ER1	Energy Grid Rehabilitation and Reconstruction
ER2	Electrical Power Reliability and Resilience
ESCR	equivalent circuit-based short circuit ratio
EUL	expected useful life
EV	electric vehicle
FAASt	FEMA's Accelerated Awards Strategy
FACTS	Flexible AC transmission systems
FARMS	Fast All-sky Radiation Model for Solar
FCR	fixed charge rate
FEMA	Federal Emergency Management Agency
FFR	fast frequency response
FIDVR	fault-induced delayed voltage recovery
FNET	frequency monitoring network

FOMB	Financial Oversight and Management Board for Puerto Rico
FRED	Federal Reserve Economic Data
FRT	fault ride-through
FTE	full-time equivalent
FY	fiscal year
GFL	grid-following
GFM	grid-forming
GHI	global horizontal irradiance
GIST	Grid Impedance Scan Tool
GNP	gross national product
GOES	Geostationary Operational Environmental Satellite
GRS	general residential service
GW	gigawatts
HAPC	habitat areas of critical concern
HOTOSM	Humanitarian Open Street Map
hr	hour
HSDS	Highly Scalable Data Service
HUD	U.S. Department of Housing and Urban Development
IBR	inverter-based resource(s)
ICS	industrial control systems
IEC	International Electrotechnical Commission
IPP	independent power producer
IREC	Interstate Renewable Energy Council
IRP	integrated resource plan
ITC	investment tax credit
JEDI	Jobs and Economic Development Impact
k	thousand
km	kilometer
LBW	land-based wind
LCOE	levelized cost of energy
LCOT	levelized cost of transmission
LEAD	Low-income Energy Affordability Data tool
LED	light-emitting diode
LESA	Land Evaluation and Site Assessment
LMI	low- and moderate-income
LUMA	LUMA Energy
LVRT	low-voltage ride-through
m	meter
MACRS	modified accelerated cost recovery system
MATOC	Multiple Award Task Order Contract
MBE	mean bias error
MHDV	medium- and heavy-duty vehicles
min	minute
MODIS	Moderate Resolution Imaging Spectroradiometer
ms	milliseconds
MVA	megavolt ampere

MW	megawatts
NDBC	National Data Buoy Center
NERC	North American Electric Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
O&M	operation and maintenance
OIPC	Independent Office of Consumer Protection
OpEx	operating expenditure
OpenDSS	an electric power distribution system simulator
OSW	offshore wind
PaaS	platform as a service
PBL	planetary boundary layer
PCM	production cost modeling
PFF	project finance factor
PNNL	Pacific Northwest National Laboratory
POI	point of interconnection
PPOA	power purchase and operating agreement
PR	Puerto Rico
PR100	Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study
PR-ERF	Puerto Rico Energy Resilience Fund
PRAS	Probabilistic Resource Adequacy Suite
PRASA	Puerto Rico Aqueduct and Sewer Authority
PRDOH	Puerto Rico Department of Housing
PREB	Puerto Rico Energy Bureau
PREPA	Puerto Rico Electric Power Authority
PRIIA	Puerto Rico Infrastructure Interdependency Assessment
PRSN	Puerto Rico Seismic Network
PSCAD	software used to design and simulate electric power systems
PSM	Physical Solar Model
PSSE	Power System Simulator for Engineering
PTC	production tax credit
pu	per unit
PUC	Public Utilities Commission
PV	photovoltaics
PVD	present value of depreciation
PV-SMaRT	Photovoltaic Stormwater Management Research and Testing
PyDSS	Python wrapper for OpenDSS that expands on its capabilities
PySAM	open-source code that allows SAM functions to be called from Python
QSTS	quasi-static time series
RA	resource adequacy
RCP	Representative Concentration Pathway
ReEDS	Regional Energy Deployment System
ReNCAT	Resilient Node Cluster Analysis Tool
reV	Renewable Energy Potential Model

ROCOF	rate of change of frequency
RPS	renewable portfolio standard
RROE	rate of return on equity
RSA	Recovery Simulator and Analysis
s	seconds
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SAM	System Advisor Model
SCADA	supervisory control and data acquisition
SCMVA	short-circuit megavolt-amperes
SCR	short circuit ratio
SEEDS	Solar Energy Evolution and Diffusion Studies
SOC	state of charge
SSP	Shared Socioeconomic Pathway
STATCOM	STATic synchronous COMpensator
SVC	Static VAr Compensator
SVI	Social Vulnerability Index
T&D	transmission and distribution
TPP	transition period plan
TR	tax rate
TRM	Technical Reference Manual
UFLS	under-frequency load shedding
UFLT	under-frequency line tripping
UPRM	University of Puerto Rico at Mayagüez
USGS	U.S. Geological Survey
VFD	variable frequency drive
VIEET	U.S. Virgin Islands Energy Efficiency Tool
WACC	weighted average cost of capital
WAP	Weatherization Assistance Program
WECC	Western Electricity Coordinating Council
WRF	Weather Research and Forecasting
WSCR	weighted short circuit ratio
yr	year

Executive Summary

The Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study (PR100) is a comprehensive analysis based on extensive stakeholder input of possible pathways for Puerto Rico to achieve its goal of 100% renewable energy by 2050. In this executive summary of the PR100 Final Report,[1] we describe the background and motivation behind the study, provide an overview, summarize results, highlight key findings, and outline implementation actions for stakeholders to take in the immediate term and the near, mid, and long term to achieve Puerto Rico's energy system goals.

Background and Motivation

Puerto Rico's current electric system is complex, isolated, reliant on imported fuels, and vulnerable to extreme weather events and other natural hazards. Decades of operational, maintenance, and financial challenges have resulted in a system that lags far behind accepted reliability levels. Puerto Rico experienced one of the longest power outages in U.S. history after Hurricane Maria in 2017, which caused billions of dollars in damage and led to nearly 3,000 excess deaths by one estimation (Santos-Burgoa et al. 2018) or more than 4,500 by another (Kishore et al. 2018), followed by long-duration outages after earthquakes in 2020 and Hurricane Fiona in 2022. Frequent outages continue to impact Puerto Ricans on a day-to-day basis, caused in part by the poor state of repair of the electric transmission and distribution grid and insufficiency of the current generation fleet, which is frequently unable to supply enough electricity to meet load under even normal, non-peak conditions (PREB 2022b).

In 2019, the Puerto Rico legislature passed the Puerto Rico Energy Public Policy Act (Act 17) (Puerto Rico Legislative Assembly 2019), setting a goal for the Commonwealth to meet 100% of its electricity needs with renewable energy by 2050 and interim targets of 40% by 2025, 60% by 2040, the phaseout of coal-fired generation by 2028, and a 30% increase in energy efficiency by 2040. Yet, energy system recovery, efforts to increase resilience, and progress toward renewable energy targets have been uneven. With 3%–5% renewable energy on the grid by mid-2023, and total utility-scale renewable energy capacity of 226 MW as of October 2023 (~137 MW of which is utility-scale solar PV) (LUMA 2023d), achieving the 40% target by 2025 would represent an increase of at least 3 GW of additional renewable energy capacity if met with utility-scale solar. Although the procurement of utility-scale renewable energy has been slow, the pace of distributed solar PV adoption is accelerating, increasing from 228 MW of total installed generation capacity in June 2021 to 680 MW in October 2023 (LUMA 2023d), a 3× increase in just over two years.

Since Hurricane Maria in 2017, the U.S. government has provided unprecedented support to Puerto Rico. The Federal Emergency Management Agency (FEMA), the U.S. Department of Housing and Urban Development (HUD), and other agencies have committed historical levels of funding to restore and build a more reliable and resilient energy system for Puerto Rico.[2] The U.S. Department of Energy (DOE) and six of its national laboratories have provided Puerto Rico

[1] Access the final report from the PR100 website and data viewer, https://www.pr100.gov/.

[2] Obligated funds include FEMA hazard mitigation assistance ($7.8 billion), FEMA public assistance ($9.5 billion), U.S. HUD Community Development Block Grant (CDBG)–Disaster Recovery: Electric Grid ($1.9 billion), HUD CDBG Community Energy and Water Resilience Installations Program ($800 million), and the Puerto Rico Energy Resilience Fund ($1 billion). Funding figures come from the respective federal agencies.

energy system stakeholders with tools, training, and modeling support to enable planning and operation of the electric system with more resilience against future disruptions.[3] A memorandum of understanding between DOE, the U.S. Department of Homeland Security, HUD, and the Commonwealth of Puerto Rico signed in February 2022 (DOE 2022b) enhanced collaboration among federal agencies and the Commonwealth.

As part of this ongoing support to ensure recovery activities are aligned with Puerto Rico's renewable energy goals, in 2022 DOE and FEMA launched PR100, a study led by the National Renewable Energy Laboratory (NREL) with contributions from Argonne National Laboratory, Lawrence Berkeley National Laboratory, Oak Ridge National Laboratory, Pacific Northwest National Laboratory, and Sandia National Laboratories. PR100 explored possible pathways for Puerto Rico to reach its goal of 100% renewable energy in the long term (by 2050), increase reliability and resilience in the immediate term (within the next few years), and work toward energy justice. The purpose of the study is to provide decision support and inform investment decisions for implementers of Puerto Rico's energy transition.

Concurrent with the study, LUMA, the transmission and distribution system operator for the government-owned Puerto Rico Electric Power Authority (PREPA), is developing an integrated resource plan (IRP) for Puerto Rico with a revised filing deadline of June 28, 2024 (PREB 2023b). In contrast with PR100, which DOE and the national laboratories conducted to answer stakeholder questions and inform investment decisions for Puerto Rico to achieve grid resilience and 100% renewable energy by 2050, the IRP is a detailed, 20-yr plan the utility is required to update every three years with broad citizen participation that, "considers all reasonable resources to satisfy the demand for electric power services..., including those related to the offering of electric power…, and those related to energy demand" (Puerto Rico Legislative Assembly 2014). Although PR100 and the IRP are separate efforts, we coordinated with LUMA to ensure that PR100 results would inform the IRP, that the processes would be complementary, and to prevent contradictions or inconsistencies between the two efforts.

Study Overview and Approach

In PR100, we defined and modeled multiple pathways for decision makers to consider for Puerto Rico to achieve its energy goals, driven by community priorities and perspectives, similar to the approach taken in the Los Angeles 100% Renewable Energy Study (LA100). We scoped PR100 to achieve the study objectives in a way that would draw on and integrate the capabilities of the six contributing national laboratories. The study is organized into 11 tasks which are further grouped into five activities (Figure ES-1).

[3] Access publications and information about DOE's technical assistance to Puerto Rico from the DOE's Puerto Rico Grid Recovery and Modernization (https://www.energy.gov/gdo/puerto-rico-grid-recovery-and-modernization) and NREL's Multilab Energy Planning Support for Puerto Rico (https://www.nrel.gov/state-local-tribal/multi-lab-planning-support-puerto-rico.html) webpages.

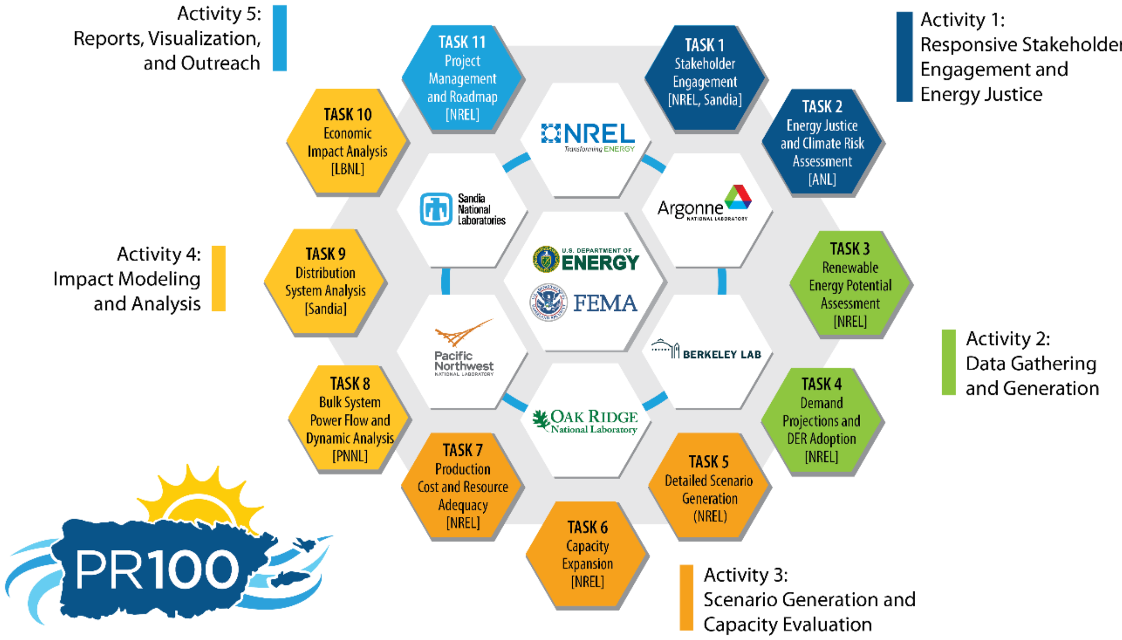

Figure ES-1. The PR100 activities and tasks are led by six contributing national laboratories.

The lead laboratory for each task is listed in brackets.

PR100 Activities

The five activities of PR100 are shown in more detail in Figure ES-2. In Activity 1, we engaged extensively with stakeholders throughout the study to understand their perspectives and priorities for Puerto Rico's energy transition and to ground PR100 in the principles and practices of energy justice. As part of our energy justice analysis, Activity 1 also included assessments of infrastructure interdependency, resilience as measured by a social burden metric, and climate risk to consider the impacts of sea level rise and other effects of climate change on the future of Puerto Rico's energy system. All analysis results were evaluated through an energy justice lens to understand the benefits and burdens of the energy system as experienced by various stakeholder groups.

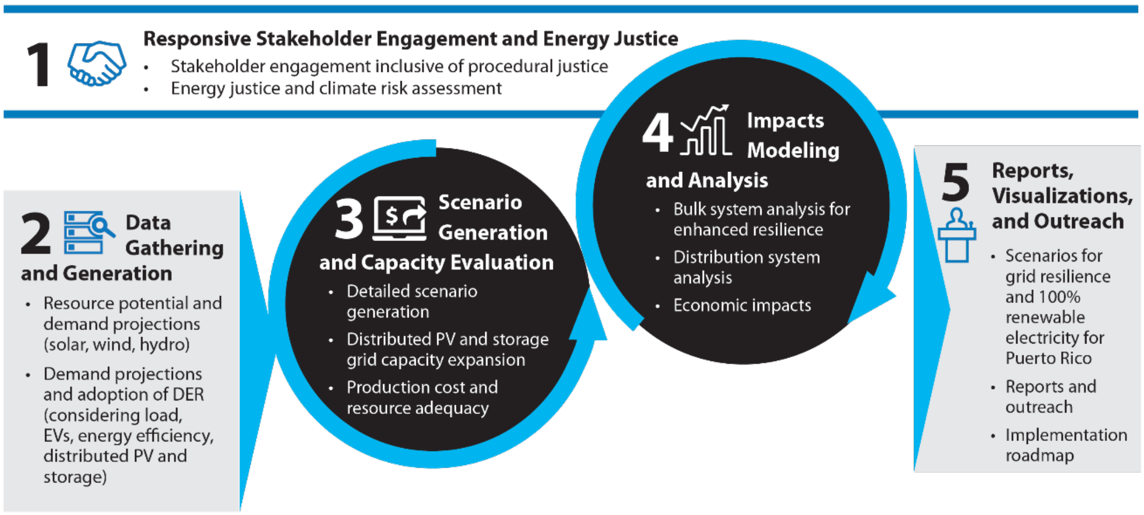

Figure ES-2. PR100 activities

In Activity 2, we gathered and generated data to use as inputs to the models. We sought stakeholder feedback on types and sources of input data, assessed the location-specific value of renewable energy resources in Puerto Rico, and evaluated areas of land and sea available for renewable energy development guided by local land use priorities. We projected electricity demand in Puerto Rico out to 2050, incorporating end-use loads, electric vehicle (EV) adoption, and energy-efficiency measures; and we modeled the adoption of distributed solar photovoltaics (PV) and storage.

In Activity 3, we defined four possible scenarios (later reduced to three) and two scenario variations, based on extensive stakeholder input, which are discussed in more detail in the Scenarios section. We modeled the scenarios to understand, based on established constraints, the cost-optimal capacity mix of energy technologies capable of delivering reliable power by year through 2050, as well as production cost and resource adequacy. In this activity we assumed that the transmission and distribution networks were repaired sufficiently to support reliable operation of the electric system, and that these repairs were completed with federal funding. Investments modeled in this activity were driven by the need to (1) achieve an adequate generation fleet to support customer demand and (2) accomplish goals established in Act 17.

In Activity 4, we analyzed the impact of the modeled scenarios on the transmission system, including its resilience to future disruptions. We studied the impacts to the distribution system and related considerations, such as microgrids. And we conducted economic impact analysis to explore potential effects on retail rates, including metrics related to changes in household income by income group under each scenario and job creation.

In Activity 5, we published progress updates at the 6-month and 1-yr mark of the study in addition to these final results in Spanish and English. Disseminations include this *PR100 Final Report*, a website and data viewer, public webinars to kick off the study and to accompany progress updates, and a public event to present our results and set the stage for implementation.[4] We conducted broad outreach to ensure that the results reached everyone with a role in the implementation of Puerto Rico's energy future.

Through the tasks and activities of PR100, the questions we sought to answer were:

Stakeholder Engagement and Energy Justice

Guiding Questions

- What investments and actions are needed immediately to ensure a reliable energy system for Puerto Rico right away while enabling long-term objectives?
- How can Puerto Rico ensure that the new system is resilient to extreme weather events?
- What are possible pathways to achieving Puerto Rico's 100% renewable energy target by 2050?
- What kinds of big changes could reaching 100% renewable energy mean for local infrastructure—like building new transmission lines or upgrading distribution feeders to increase hosting capacity for distributed generation?
- If Puerto Ricans adopt energy technologies like electric vehicles, how might that change the total demand for electricity?
- What are the impacts of the energy transition on jobs and the local economy?
- What needs to be done to support an equitable energy transition for all Puerto Ricans?

While the national laboratories had scoped PR100 to conduct modeling and analysis about how Puerto Rico could reach 100% renewable energy, once the study began, we worked closely with members of an Advisory Group to define the scenarios to be modeled such that the results would answer their questions about trade-offs and projected outcomes between multiple pathways to achieve Puerto Rico's energy goals. We also sought their feedback on study methods, inputs, assumptions, and results. As of October 2023, the Advisory Group had 116 confirmed members representing 73 organizations, including universities and other research institutions; federal and Puerto Rico government entities; solar and storage industries; finance, legal, community-based, and environmental organizations; retail, manufacturing, and consultants; and other sectors. A Steering Committee of leaders from federal and Puerto Rico government agencies[5] provided additional guidance (see Acknowledgments, page iv, for a list of members and affiliations).

In the second year of the study (Year 2), we broadened our engagement to include a community engagement tour and industry sector roundtables, conducted in partnership with the Puerto Rico Grid Modernization and Recovery Team led by U.S. Secretary of Energy Jennifer Granholm. Through these events, we deepened our understanding of how communities and organizations are affected by the current energy system and what they want and do not want to see in the

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[4] Access publications and information about DOE's technical assistance to Puerto Rico from the DOE's Puerto Rico Grid Recovery and Modernization (https://www.energy.gov/gdo/puerto-rico-grid-recovery-and-modernization) and NREL's Multilab Energy Planning Support for Puerto Rico (https://www.nrel.gov/state-local-tribal/multi-lab-planning-support-puerto-rico.html) webpages.

[5] FEMA, HUD, PREPA, LUMA, Genera PR, the Puerto Rico Energy Bureau (PREB), the Puerto Rico Department of Housing (PRDOH or Vivienda), the Puerto Rico Department of Economic Development and Commerce (DDEC) Energy Policy Program, and the Central Office for Recovery, Reconstruction and Resiliency (COR3).

energy system of the future. The four primary groups of stakeholders with which we engaged are shown in Figure ES-3.

Figure ES-3. Four primary groups of stakeholders with which we engaged

We partnered with the Hispanic Federation in Puerto Rico to advise on stakeholder engagement and contribute to planning and facilitation of stakeholder meetings and community events. We found that partnering with a local organization to facilitate events and advise on our engagement strategy was immensely valuable, and ultimately expanded and deepened our connection with stakeholders and strengthened the study overall. We also partnered with a group of professors and graduate students at the University of Puerto Rico at Mayagüez (UPRM) for input on PR100 and to support collaboration with related research efforts at the university. UPRM produced a series of memos summarizing their input on PR100 modeling and energy justice metrics, which informed modeling decisions and scenario development (M. J. Castro-Sitiriche et al. 2023; Irizarry-Rivera et al. 2023; Lugo-Hernández et al. 2023).

Through our work with stakeholders, we deepened our understanding that individuals and organizations across Puerto Rico have divergent experiences, priorities, and visions for the future energy system. Some are strong proponents of a highly distributed system while others favor a larger role for utility-scale renewables. We heard from stakeholders that rooftop solar and storage and preservation of agricultural land are high priorities in communities across Puerto Rico; common challenges include not having property title, structural concerns that make buildings not suitable for rooftop solar, frequent flooding, and energy-dependent water systems that do not work during outages. Findings from research conducted by project partners at UPRM highlight the need to focus on duration to restore power to 100% of customers after outages and prioritize resilient, renewable energy access for the last 5% of customers who are most vulnerable to long-duration power outages.

An overarching activity of PR100 was to ground the study in principles and practices of energy justice, which are defined in the literature as, "…the goal of achieving equity in both the social and economic participation in the energy system, while also remediating social, economic, and health burdens on those historically harmed by the energy system" (Baker, DeVar, and Prakash 2019). The five pillars of energy justice that we sought to integrate throughout the study are procedural, recognition, distributive, restorative, and transformative (see Figure ES-4 for definitions). We involved an inclusive group of stakeholders, adhered to just practices for energy planning, and conducted an energy justice literature review with a focus on Puerto Rico that included local knowledge. When we asked Advisory Group members about their visions for a just energy transition for Puerto Rico, themes that emerged were:

- Energy access, affordability, reliability, and resilience
- Community participation
- Economic and workforce development
- Siting and land use
- Environmental and health effects
- Public sector implementation.

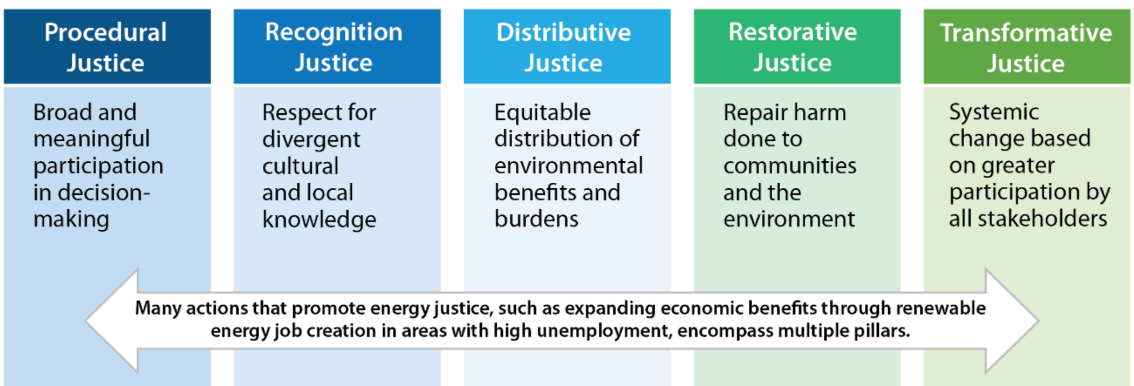


Figure ES-4. Five pillars of energy justice

Sources: Jenkins et al. (2016), Heffron and McCauley (2017), Baker et al. (2019), and Lee and Byrne (2019)

Scenarios

Based on extensive stakeholder engagement, it became clear that the extent of Puerto Rico's reliance on distributed generation is a key uncertainty regarding Puerto Rico's policy and investment strategy over the coming years. To explore the implications of varying levels of distributed generation, we worked closely with stakeholders to define three scenarios to answer questions about trade-offs and possible outcomes for PR100.[6] We defined Scenario 1 as the economic adoption of distributed energy resources (DERs) based primarily on bill savings and value of backup power for building owners (Economic) and Scenario 3 as the maximum deployment of DERs on all suitable rooftops (Maximum). Because resilience was a high priority, we defined Scenario 2 between the bookends to extend DER adoption beyond Scenario 1 levels

[6] Initially, we defined four scenarios, and based on preliminary modeling results, we reduced the number to three scenarios. See (Blair et al. 2023) (page 3) for a detailed discussion.

to very low-income households (0%–30% of area median income) and those in remote areas who would not have bought systems solely based on economics (Equitable). The three scenarios modeled in PR100 are shown in Figure ES-5.

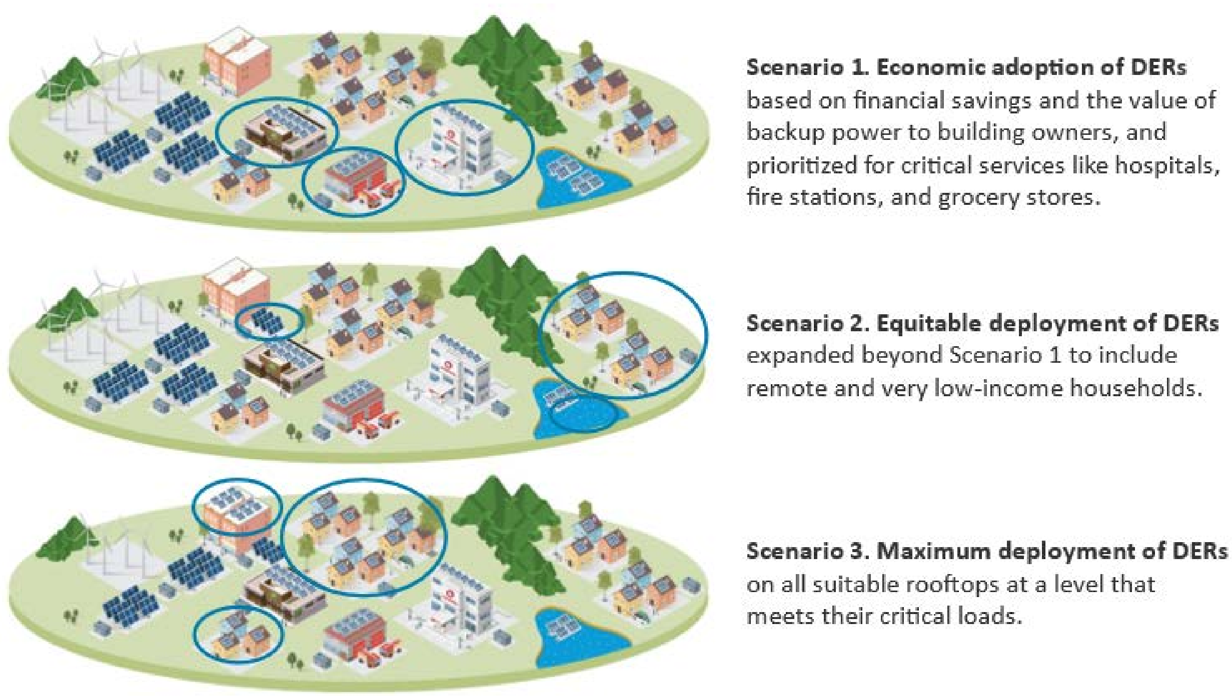


Figure ES-5. Three scenarios modeled in PR100, distinguished by varying levels of DER adoption

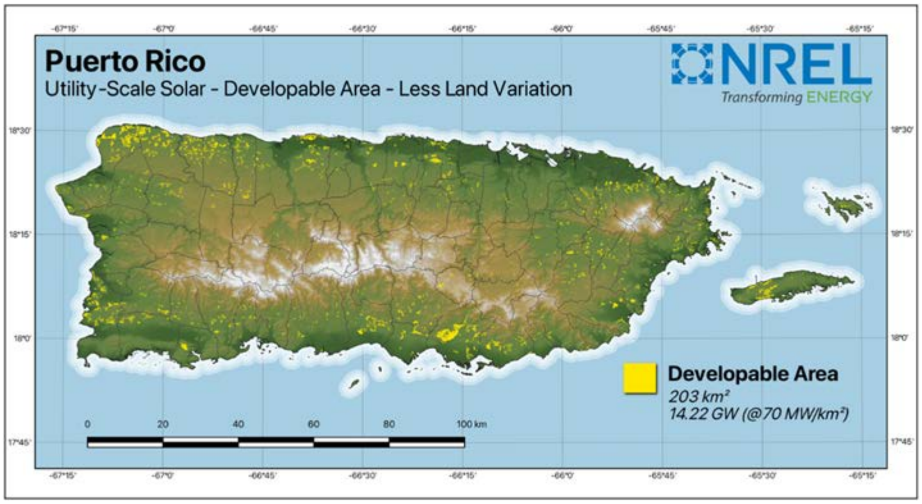
Differences between scenarios are circled in blue.

We defined remote communities based on outage duration after a major disruption such as Hurricane Maria, typical outage durations in the absence of a storm or other disruptive event, and input from local experts, including project partners at UPRM. For modeling Scenario 2 (Equitable), we defined remote communities as the 18 municipalities in Puerto Rico represented in Figure ES-6.

Figure ES-6. Scenario 2: Map of modeled remote municipalities in Puerto Rico

We also defined two variations, or sensitivities, to apply to the three scenarios. The land use variation includes two variants, Less Land and More Land, based on stakeholder feedback that the preservation of agricultural land is a high priority for many people. Figure ES-7 shows the developable area (shaded yellow) for utility-scale solar PV in each land use variant. Modeling this variation allows for an assessment of whether Puerto Rico's renewable energy goals can be met by developing utility-scale projects only on land not designated for agricultural purposes, or whether development on agricultural land may be required to meet demand with 100% renewable energy.

In both land use variants, development of utility-scale solar PV and wind is restricted from areas such as roadways, water bodies, protected habitats, flood risk areas, slopes greater than 10%, and agricultural reserves. In the Less Land variant, development of utility-scale projects is also restricted from areas identified for agricultural use in the 2015 Land Use Plan (Puerto Rico Planning Board 2015). In the More Land variant (Figure ES-7, bottom), 638 km^2 are available for solar development, with technical potential of 44.66 GW; in Less Land (top) the developable area is 203 km^2 with technical potential of 14.22 GW.



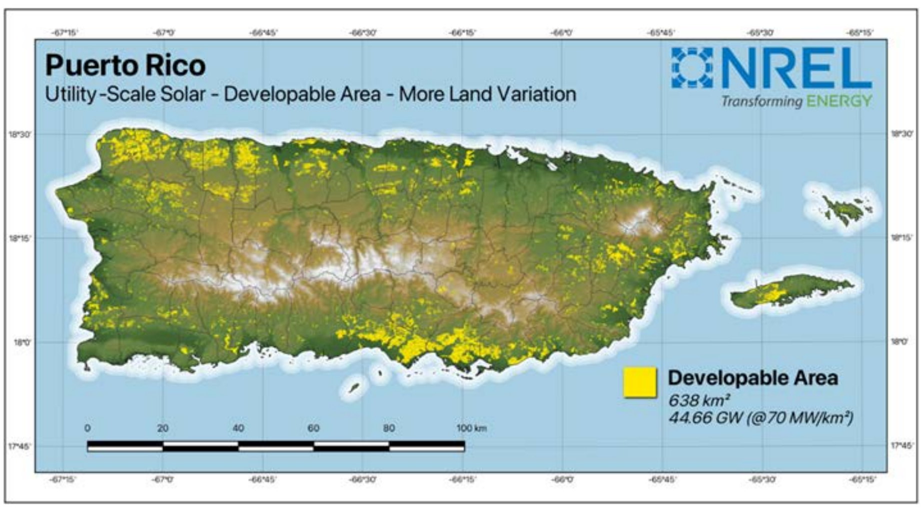


Figure ES-7. Two land use variations: Less Land (top) and More Land (bottom)

The developable area for utility-scale solar PV is shaded yellow.

Due to the uncertainty around electric load projections out to 2050, we also defined an electric load variation with two variants, Mid case and Stress (Figure ES-8, page xxiv). The purpose of defining a Stress load variant in addition to the Mid case was to help decision makers not to underplan in the event the load does in fact increase and to account for uncertainty in the inputs to the end-use load calculation. As discussed in the Summary of Results and Key Findings, capacity expansion and resource adequacy modeling show that total capacities are higher in the Stress scenario variations, and that additional capacity is required in both Mid case and Stress scenario variations to meet demand and reliability metrics without the need for deployment of emerging technologies.

Projecting electric load involved modeling changes in end-use load parameters, such as population size, manufacturing employment, gross domestic product, and climate; and taking into consideration the load impacts from electric vehicle (EV) adoption and energy efficiency. The Mid case end-use load projection showed slightly decreased end-use electricity sales over time, primarily due to forecasted long-term declines in population and real gross national product. To account for a possible future in which loads do not decline as projected, we developed a Stress load which assumes the combination of end-use loads and energy efficiency will result in flat annual electricity sales and electric loads from FY23 to FY51. Adding projected growth of electric vehicle adoption and resultant electricity loads results in increasing load as shown in the Stress load projection in Figure ES-8.

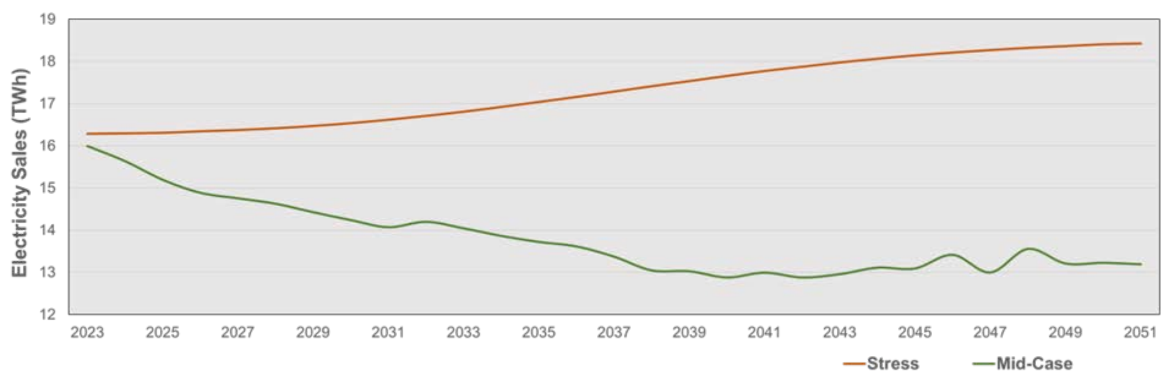


Figure ES-8. Two annual electric load variations: Mid case (green) and Stress (orange)

Combining the three scenarios with two variations, each with two variants, resulted in 12 total scenario variations modeled in PR100. Scenario identifiers referenced in the study results combine the scenario number with letters to represent the scenario variations, such that 1LS, for example, represents Scenario *1* (Economic), *L*ess Land, *S*tress load. See Section 6.1.7 (page 183) for a table of the 12 scenario variations and their scenario identifiers.

Ultimately the range of scenario variation modeling results is fairly small in the next few years; one of the primary takeaways from the analysis overall, discussed further in Implementation Actions, is that regardless of scenario or source of renewable energy, increased capacity is needed on the system immediately to achieve a robust[7] electric system for Puerto Rico.

Summary of Results and Key Findings

This section summarizes PR100 results and key findings. We start at a high level with results of an assessment of renewable energy resource potential in Puerto Rico, followed by an evaluation of the demand for electricity and how it is projected to change over time considering end-use loads and adoption of energy efficiency measures and electric vehicles. Then we present results

[7] Throughout this report the term "robust" refers to the state of repair of the electric system.

of a series of interdependent modeling and analysis exercises evaluating the defined scenarios and variations through 2050 given targets defined in Act 17 and additional assumptions and constraints listed in Appendix B. For each relevant scenario-variation we modeled the adoption of distributed solar and storage by income group, build-out of generation capacity, resource adequacy, and production cost to meet demand and system requirements, impacts on the transmission and distribution systems, and economic impacts. We also conducted assessments of infrastructure interdependency, social burden, and climate risk for Puerto Rico, which are not discussed in this summary report.

Detailed results of these analyses—including methodologies, assumptions, inputs, and interpretations for each topic—can be found in the *PR100 Final Report*.

Resource Assessment

We conducted assessments of a variety of renewable energy resources in Puerto Rico to evaluate whether the resource potential of solar, wind, hydro, and other sources is sufficient to meet Puerto Rico's goal of 100% renewable energy.[8] To answer this question, we generated high-resolution, multiyear resource data sets for land-based wind, offshore wind, as well as wind and solar forecast data, and evaluated the resource potential of hydropower and ocean thermal resources. We assessed the developable area and technical potential for utility-scale solar, land-based wind, and offshore wind, among other technologies. Results for utility-scale solar are represented in the land use scenario variation (Figure ES-7, page xxiii).

The resource data are used to determine the renewable energy technical potential of a given technology to define its achievable energy generation given system performance, topographic, environmental, and land use constraints. Technical potential is the total amount of a resource that could be deployed; it is only limited by physical constraints (e.g., rooftop area, available land area, and technical efficiency), and does not indicate likely deployment. Figure ES-9 shows the 25-yr average solar irradiance by global horizontal irradiance (GHI) for Puerto Rico, and Figure ES-10 shows the 20-yr mean wind speeds, wind direction at 160 m, and terrain height for Puerto Rico. Appendix A.3 (page 658) provides instructions on how to access the data.

[8] In our modeling, we include only generation technologies that meet the definition of renewable energy in the Public Policy on Energy Diversification by Means of Sustainable and Alternative Renewable Energy in Puerto Rico Act (Act 82 of 2010, as amended). Consistent with this policy, technologies considered in PR100 include solar energy, wind energy, hydropower, marine and hydrokinetic renewable energy, ocean thermal energy, and combustion of biofuel derived solely from renewable biomass.

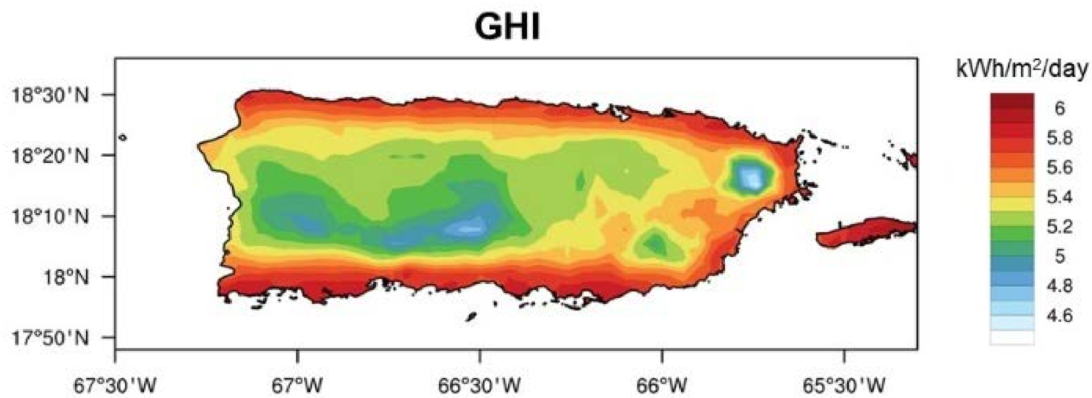


Figure ES-9. Map of 25-yr average GHI for Puerto Rico

This map shows daily average GHI for 25 years of data using 4-km and 30-min resolution National Solar Radiation Database (NSRDB)[9] data sets.

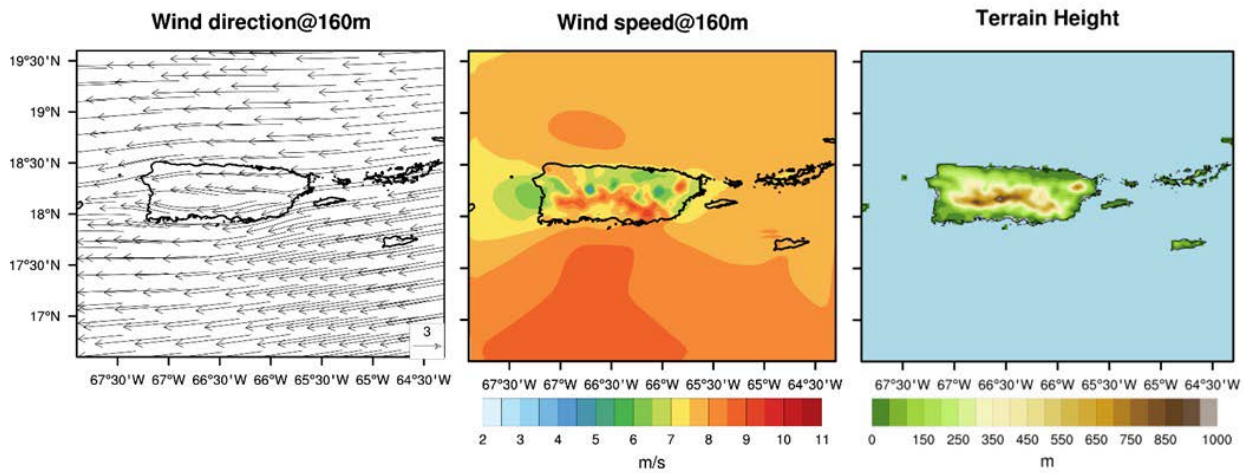


Figure ES-10. Maps of 20-yr mean wind speeds, wind direction at 160 m, and terrain height for Puerto Rico

We found that while the Less Land variation provides sufficient developable area to meet annual load, the reduced land area is anticipated to result in the development of a greater number of smaller solar PV and land-based wind plants that are more dispersed across Puerto Rico, while the More Land scenario is more likely to result in larger but fewer plants. Due to the reduced economies of scale and increase in required infrastructure (e.g., access roads, interconnections, etc.) the costs associated with deployment under the Less Land scenario are higher on average than the More Land scenario across all modeled years and technology scenarios. In summary, more utility-scale solar PV capacity is available for each site at a lower levelized cost of electricity (LCOE) on average in scenarios where more land is available for development than

[9] https://nsrdb.nrel.gov/data-sets/how-to-access-data

less land ($75/MWh PPOA LCOE[10] and 44.67 GW for More Land and $79/MWh.and 14.22 for Less Land in 2030 for expected levels of technology innovation) (Figure 11).[11]

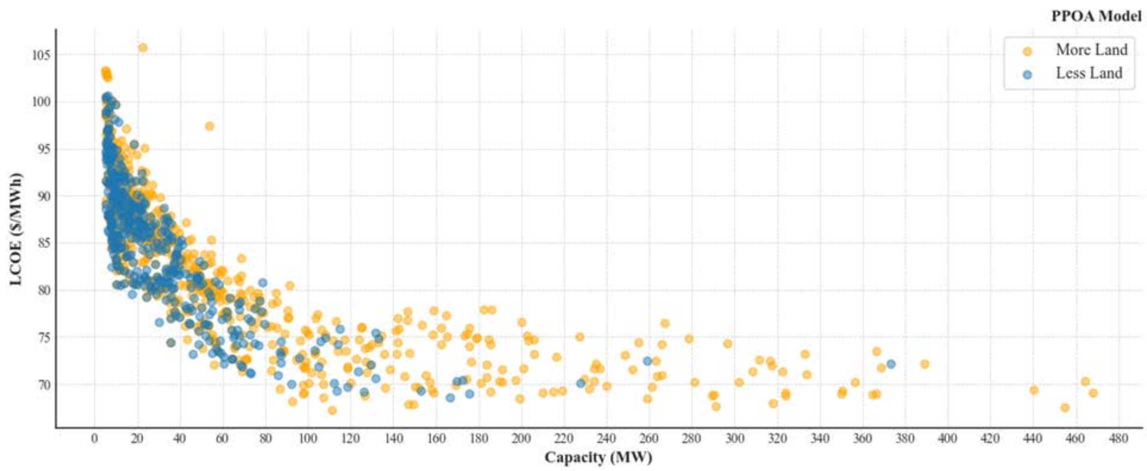


Figure ES-11. Total LCOE by plant capacity in 2030 for expected levels of technology innovation

We used results of an NREL analysis conducted by Mooney and Waechter (2020) to assess (1) how rooftop solar potential in Puerto Rico is distributed geographically, by income group, building type, and tenure of the building occupants and (2) how much electrical consumption can be offset by rooftop solar. The analysis processed 2015–2017 light detection and ranging (lidar) scans covering 96% of Puerto Rico's building stock. The lidar data were intersected with Census demographics tables of household counts by income, tenure, and building type. Solar generation was simulated for each roof plane using NREL's PVWatts and was aggregated at the tract and county level. Figure ES-12 illustrates the methodology. Results show the potential annual generation for all residential buildings is 24.6 TWh/year with potential capacity of 20.4 GW-dc. For low- and moderate-income households the potential annual generation is 11.9 TWh/year with potential capacity of 9.8 GW-dc.

[10] Using cost and financing assumptions derived from public power purchase and operating agreements (PPOAs) in Puerto Rico, the capacity expansion modeling team developed a process for calculating LCOEs under Annual Technology Baseline technology future scenarios (https://www.nrel.gov/analysis/data-tech-baseline.html).

[11] For a detailed discussion of these findings including the PPOA LCOE model and technology scenarios see the *PR100 Final Report*.

Figure ES-12. Summary example of rooftop PV analysis methodology

Source: Mooney and Waechter (2020)

We found that renewable energy resource potential assessed for Puerto Rico exceeds by more than tenfold what is required to meet the current and projected total annual loads through 2050 (Figure ES-13, page xxix). Moreover, electric load can be met with mature technologies, such as distributed PV, utility-scale PV, utility-scale wind, storage, and reciprocating engines running on biofuels. A key finding from this analysis is that utility-scale PV deployment on nonagricultural land is sufficient to meet total annual electric load to 2050 in our scenarios. Achieving the 100% target would not require any technological breakthroughs. Emerging technologies could further diversify the technology mix in the future.

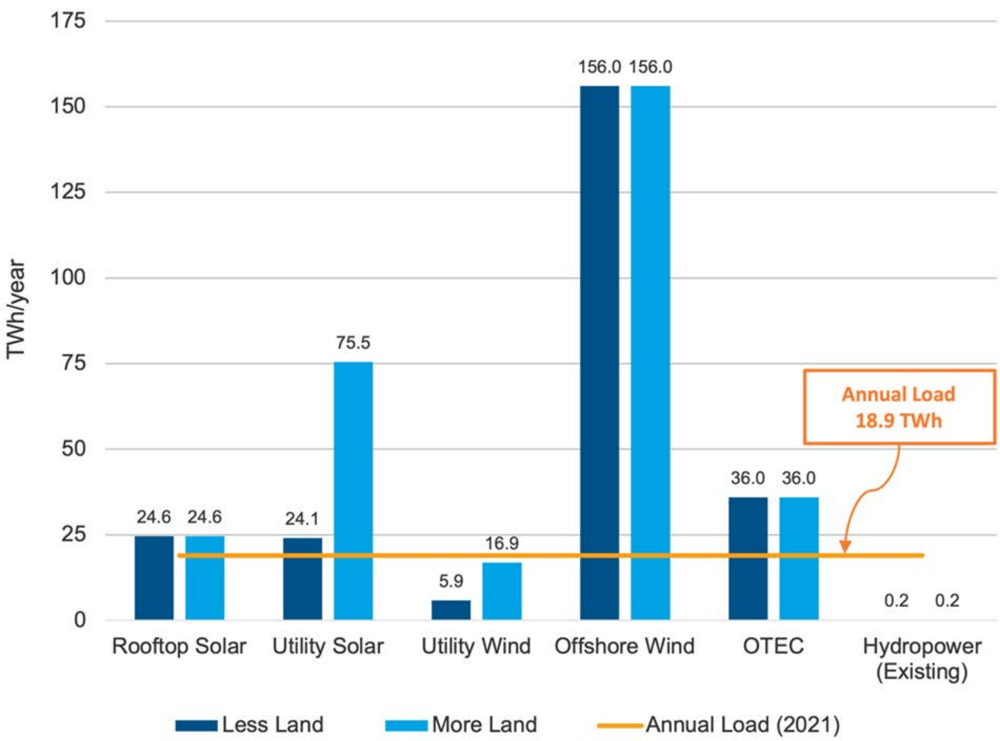


Figure ES-13. Potential annual generation in TWh of various renewable technologies compared to annual load in Puerto Rico in 2021

> ### *Key Findings*
>
> - Renewable energy potential assessed for Puerto Rico exceeds the current and projected total annual loads by more than tenfold through 2050.
> - The technical potential of mature technologies—utility-scale PV, distributed PV, and land-based wind—is sufficient to achieve Puerto Rico's renewable energy goals.
> - Emerging technologies may further diversify the technology mix in the future.
> - Utility-scale PV deployment on nonagricultural land is sufficient to meet total annual electric load to 2050 in our scenarios.

Electric Load

As discussed in the Scenarios section above, we modeled projected changes in electric load in Puerto Rico by modeling end-use load parameters, such as future population size, changes to manufacturing employment, gross domestic product, and climate, as well as load impacts from electric vehicle (EV) adoption and energy efficiency. End-use loads are items in a building that use electricity, such as air conditioning, refrigeration, cooking equipment, lighting, plug loads and industrial loads. In this analysis, we took existing hourly end-use loads to determine whether in the future these profiles would increase or decrease from year to year. As noted above, we found that end-use loads are anticipated to decrease across Puerto Rico by 2050 in the Mid case trajectory, based primarily on population and economic forecasts, so we developed a second trajectory called the Stress load which assumes the combination of end-use loads and energy efficiency will result in flat annual electricity sales and, due to the addition of EV loads, load trajectory increases.

In our energy efficiency analysis, we modeled the trajectory necessary to achieve Puerto Rico's goal of 30% energy efficiency by 2040 (Puerto Rico Legislative Assembly 2014, 57), as well as a second trajectory where the energy efficiency increases based on the annual consumption of each end use, the projected increase in efficiency of the relevant technology, and the estimated annual percent of technology stock turn-over . In the bottom-up analysis, we modeled the hourly impact of future energy efficiency adoption on the electricity load forecast. The savings are from natural turnover and codes and standards as well as programs. A key finding from these two approaches is that achieving the 30% goal is ambitious as compared with the bottom-up analysis results, which show an 18% increase by 2050.

We also projected adoption of light-duty as well as medium- and heavy-duty EVs (MHDEVs) and the contribution to electric load. We based our estimate of the number of light-duty EVs in Puerto Rico from now until 2050 on U.S. Census and open-source road network GIS data to estimate driving energy consumption and charging locations. For MHDEVs we estimated travel patterns of existing medium- and heavy-duty vehicles in Puerto Rico and then determined the amount and geographical distribution of energy required to charge the MHDEV population assuming the adoption trend follows an S-curve, based on a 5% annual replacement of existing vehicles in the fleet, with the fraction of EVs growing by 4% every year between 2025 and 2050. We then applied charging schedules for the different end uses of MHDEVs to driving patterns to construct electric load shapes. A key finding is that 25% of light-duty vehicles and 48% of medium- and heavy-duty vehicles were estimated to be electric by 2050.

The Mid case and Stress load results of the electric load scenario variation (Figure ES-8, page xxiv) represent the combined contributions of three components. Figure ES-14 and Figure ES-15 show the contributions of these three components in the Mid case and Stress load variations. Based on LUMA data, total electricity sales for Puerto Rico were 16,282 GWh in FY22. In the Mid case variant, sales were projected to decline to 14,240 GWh in FY30 and to 13,192 GWh in FY51, with EVs accounting for 2% of electricity sales in FY30 and 16% in FY51.

In the Stress variant, electricity sales are projected to rise to 16,537 GWh in FY30 and to 18,422 GWh in FY51, with EVs accounting for 2% of sales in FY30 and 12% in FY51. Total EV electricity sales are slightly higher in FY51 in the Stress variation; however, EV sales account for a lower percentage of total sales in FY51 compared to the Mid case variation because end-use loads are significantly higher in the Stress variation.

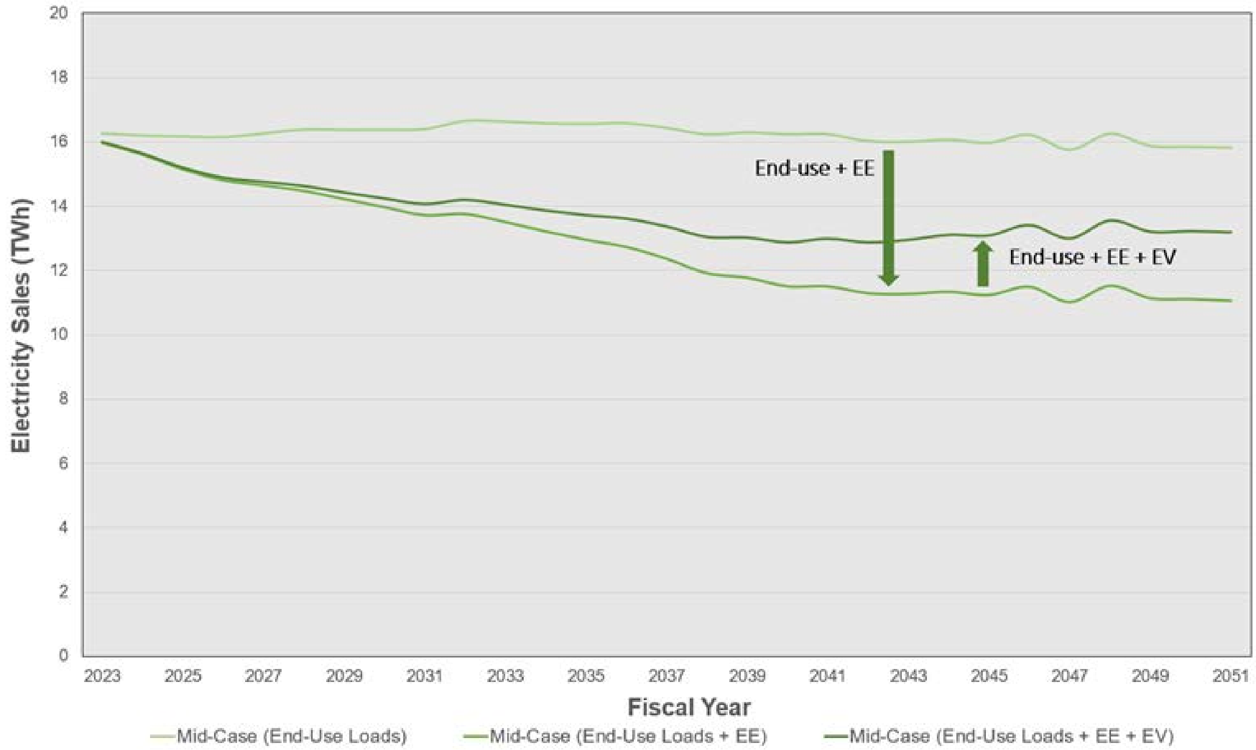


Figure ES-14. Annual electric load projections: Mid case variation, FY 2023–FY 2051

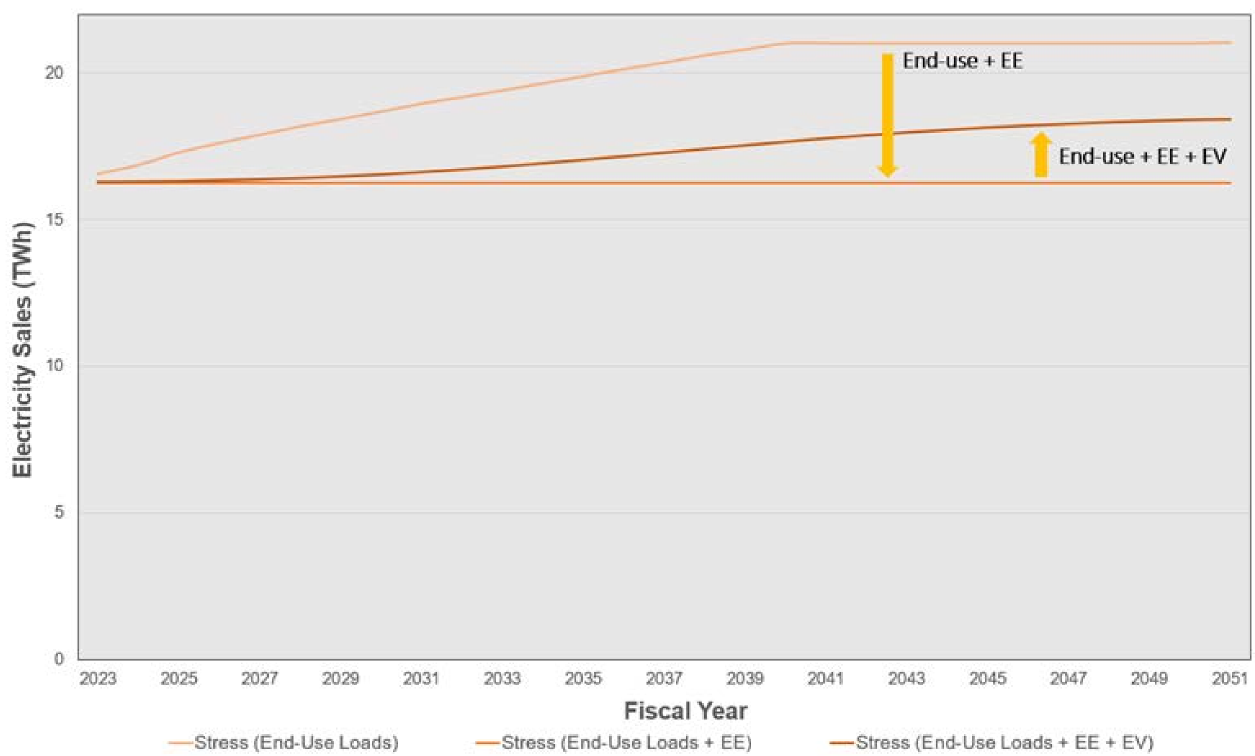


Figure ES-15. Annual electric load projections: Stress variation, FY 2023–FY 2051

Key Findings

- End-use loads are anticipated to decrease across Puerto Rico by 2050 in the Mid case trajectory, based primarily on population and economic forecasts. This trajectory of downward electricity demand is unlike most electric systems, which anticipate increasing loads even with increased energy efficiency.
- End-use loads into the future are uncertain and might not decrease, assuming other scenario changes (significant investment in the electric system resulting in a reliable grid); therefore, we examined a range of load trajectories (Mid case and Stress) anticipating that actual loads would be captured within this range.
- The current energy efficiency goal of 30% by 2040 is shown to be aggressive compared with results of our bottom-up analysis, which show 18% energy efficiency by 2050. Currently, very limited resources are available for energy efficiency improvements in Puerto Rico.
- A total of 47% of medium- and heavy-duty vehicles (MHDVs) were estimated to be electric by 2050.
- Light-duty EVs (LDEVs) are modeled to reach 25% of the overall fleet stock by 2050. This will have implications for the overall load and impact on the retail rates and other factors.

Distributed Solar Photovoltaics (PV) and Storage Adoption

We modeled the adoption of distributed solar PV and storage for each scenario using NREL's Distributed Generation Market Demand (dGen™) model.[12] We modeled six scenario variations—each of the three main scenarios combined with the load variations—because we assumed that variation in land use policies does not impact deployment of distributed generation (but rather, the adoption trajectory of distributed generation impacts how much additional renewable capacity is needed at the utility scale). As such, the range of distributed PV adoption for each scenario reflects the load trajectories in the Mid case and Stress load variations (Figure ES-8, page xxiv). The results can be summarized as follows:

- The Scenario 1 results represent the economic deployment of distributed PV based on bill savings to building owners combined with a monetized value of backup power and with adoption rates governed by historical consumer adoption behaviors (for residential, commercial, and industrial buildings) and for critical services such as hospitals, fire stations, and grocery stores. By 2050, the economic adoption of distributed PV results in 2,500 to 3,300 MW of capacity (4,000 to 5,300 TWh of generation). These levels of distributed PV are 370% to 490% higher than the 680 MW in 2023.
- For Scenario 2, in which distributed PV deployment is expanded to meet the critical loads of low-income and remote communities, results show that an additional 11%–14% of distributed PV capacity beyond Scenario 1 is deployed (for a total of 2,800 to 3,600 MW of capacity or 4,600 to 5,900 TWh of generation).
- Finally, Scenario 3, which models further expanding rooftop PV and storage to all suitable rooftops to meet critical loads across Puerto Rico, results in a total rooftop PV capacity of 5,200 to 6,100 MW by 2050 (or 8,500 to 9,900 TWh of generation), more than 100% more that of Scenario 1. Similarly, a study conducted in support of the Queremos Sol proposal, with which Scenario 3 was designed to compare, previously found that the deployment of rooftop PV and storage systems on all residential and commercial rooftops, while a

[12] https://www.nrel.gov/analysis/dgen/

somewhat different set of buildings from those modeled in PR100, would result in 5,000 MW of distributed PV capacity (Vila Biaggi, Kunkel, and Irizarry Rivera 2021).

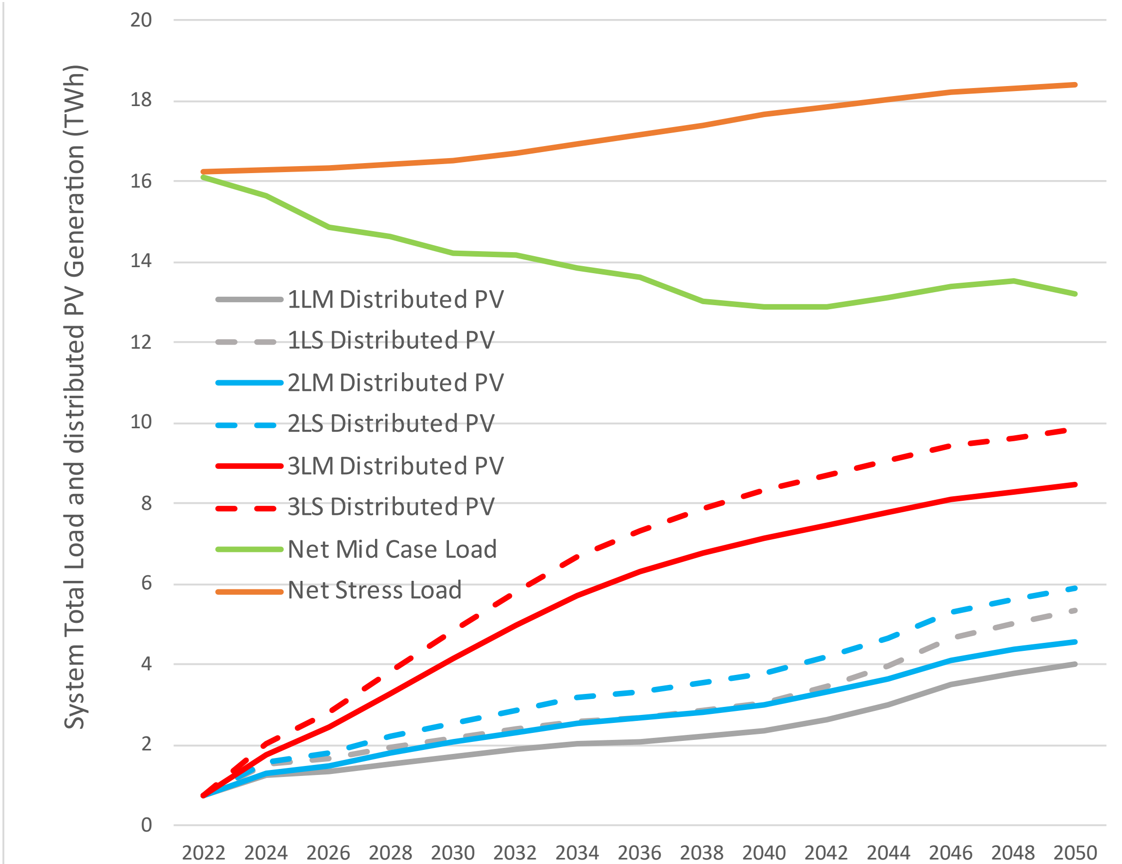


Figure ES-16. Rooftop PV generation across scenarios and Puerto Rico load forecasts plotted to demonstrate the fraction of annual load met by distributed generation

Figure ES-17, Figure ES-18, and Figure ES-19 (page xxxiv) show rooftop PV capacity per customer by municipality for each scenario by 2050. A comparison of the three maps shows increasing capacity of rooftop PV per customer from Scenario 1 to Scenario 3. For Scenario 2, as illustrated by comparison with the small map (bottom right) of municipalities we defined as remote (see Scenarios section for discussion), Scenario 2 results in more capacity per customer in remote municipalities than Scenario 1.

Figure ES-17. Year 2050 rooftop PV capacity per customer for Scenario 1 with Mid case load (1LM)

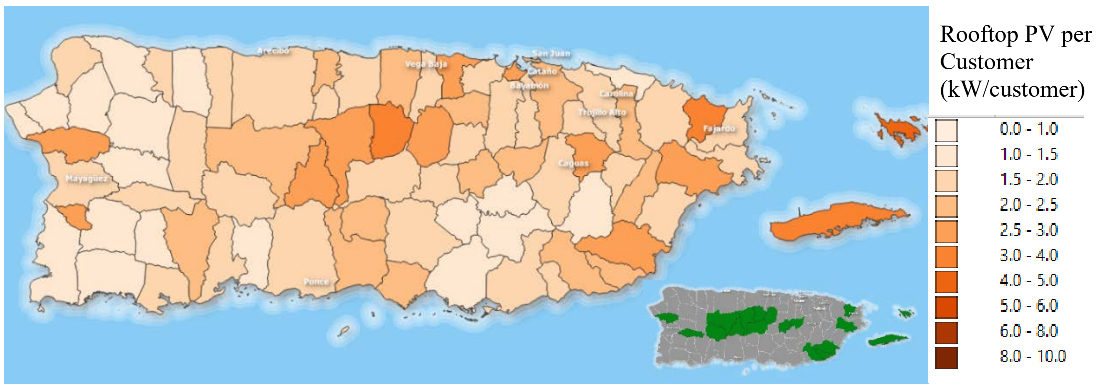


Figure ES-18. Year 2050 rooftop PV capacity per customer for Scenario 2 with Mid case load (2LM)

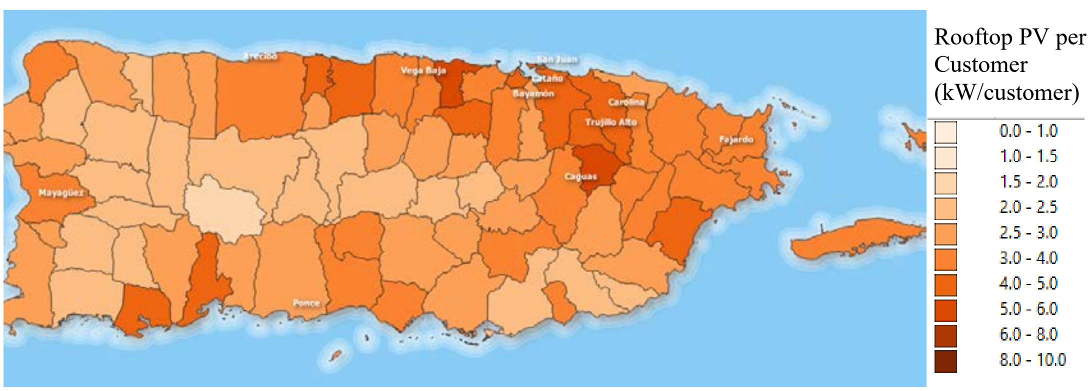


Figure ES-19. Year 2050 rooftop PV capacity per customer for Scenario 3 with Mid case load (3LM)

Our modeling assumes continuation of the current net metering compensation program out to 2050.[13] Under this framework, consumers are assumed to adopt behind-the-meter, distributed storage that is used for backup power during outages, which in 2021 occurred seven times more frequently on average in Puerto Rico than in the 50 U.S. states (FOMB 2023b). In this study, we did not model participation in demand response programs.

[13] "The rate of the compensation provided is ten (10) cents per kilowatt-hour or the amount resulting from the subtraction of the adjusted fuel fee based on the variable costs incurred by PREPA exclusively for the purchase of fuel and energy from the total price PREPA charges its customers, converted into kilowatt hours, whichever is greater" (Puerto Rico Legislative Assembly 2007).

There is uncertainty around rooftop PV and battery costs for Puerto Rico, with some evidence pointing to lower costs than we used in the modeling. Lower system costs would increase and accelerate the adoption of rooftop PV and storage capacity in Scenario 1 because rooftop PV and storage would be more economic compared to utility rates; adoption would increase in Scenario 2 for the same reason. The Scenario 3 results would not be affected because rooftop PV and storage adoption is imposed on all suitable rooftops in that scenario rather than relying on economics.

Key Findings

- Under all scenarios (Scenarios 1, 2, and 3) and variations, the amount of rooftop PV capacity and storage capacity deployed in Puerto Rico by 2050 will be significant both in aggregate (2,500 to 6,100 MW) and in the instantaneous power supplied back to the grid during the day.
- Model results indicate that rooftop PV and storage deployment will continue even as the grid becomes more resilient because of economics and the ongoing desire for local generation and backup power. As battery and PV costs continue to decrease, the deployment of rooftop PV and batteries might result in extra capacity toward 2050 if significant utility-scale renewables are built in the near term.

Integrated Capacity Investment

We conducted capacity expansion modeling to find the lowest-cost system[14] for each scenario while meeting load, Act 17, and scheduled plans for resource procurement and retirement. We began by establishing the levelized cost of electricity (LCOE) for existing and new technologies. LCOE of technologies included in modeling results for 2035 are shown in Figure ES-20.

[14] By "lowest cost," or "least-cost" we mean the lowest-cost combination of resources (generators, wires, etc.) that together have the energy production capacities to meet system electricity demand at all times. Some stakeholders pushed back against this approach because it does not account for complexities such as social or environmental costs.

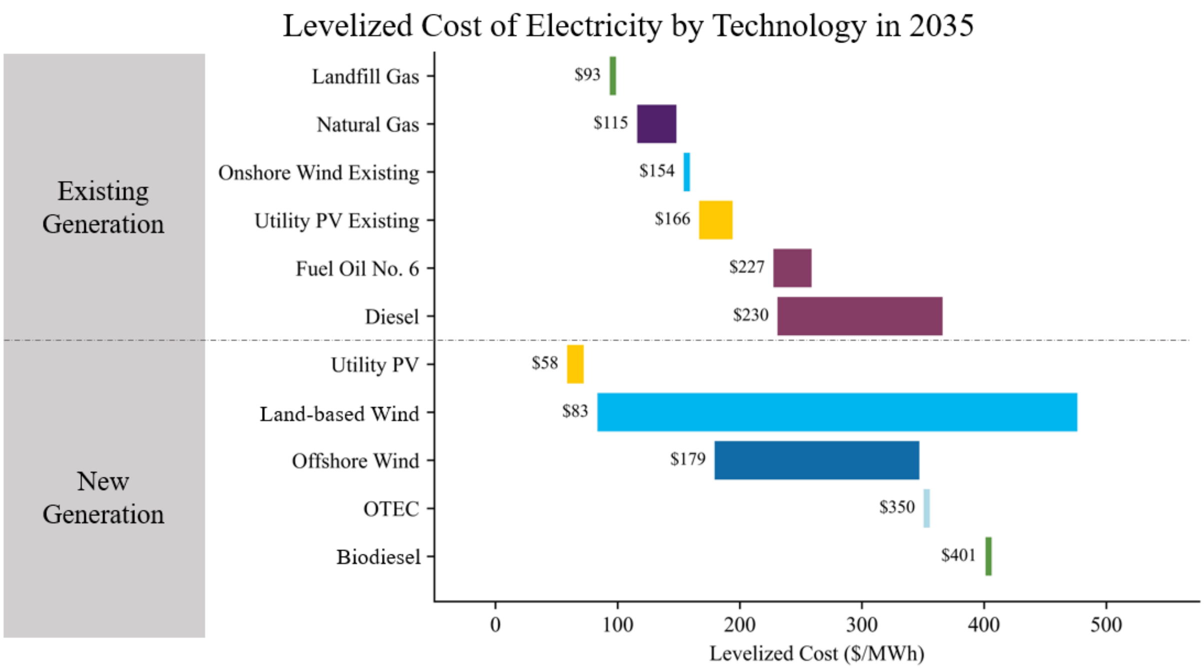


Figure ES-20. Levelized cost of electricity by technology in 2035 (costs in 2021 real dollars)

We then evaluated the system adequacy of these optimizations and augmented expansion results to achieve acceptable levels of system adequacy. By that, we mean that this analysis focused on the adequacy[15] and operational reliability[16] of future systems to minimize outages which have been so impactful in Puerto Rico. There are other reliability measures that we have not included in this project.[17]

We found that additional generation capacity is needed immediately—on the scale of hundreds of megawatts—to achieve system adequacy and minimize outages. Indeed, even if all six tranches of PREPA's Renewable Energy Generation and Energy Storage Resource Procurement Plan (PREB 2020) successfully result in capacity additions as planned, a significant investment in additional generation capacity would still be needed to achieve acceptable reliability performance.

[15] Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. https://www.nerc.com/AboutNERC/Documents/Terms%20AUG13.pdf

[16] Operating reliability is the ability of the bulk power system to withstand sudden disturbances, such as electric short circuits or the unanticipated loss of system elements from credible contingencies, while avoiding uncontrolled cascading blackouts or damage to equipment.
https://www.nerc.com/AboutNERC/Documents/Terms%20AUG13.pdf

[17] Reliability measures include but are not limited to pole replacements; transformer monitoring/replacement; recloser installation; conductor inspection and replacement; animal guards; fault location, isolation, and service restoration, etc. These are not addressed in this study.

As shown in Figure ES-21, to achieve 40% renewable energy, the optimal expansion planning results include 2,600–3,500 MW of utility-scale PV capacity, depending on the scenario, along with approximately 700 MW of 4-hr-duration utility-scale batteries, 260–400 MW of long-duration storage, and 170–340 MW of land-based wind. These utility-scale capacity additions augment the capacity added from the distributed PV and storage adoption results described in the previous section that were used as fixed inputs in the capacity expansion model. Much of the roughly 4-GW of existing fossil-fueled generation remained on the system in this phase. We observed that the current pace of utility-scale deployment is likely too slow to result in 40% renewable energy by the 2025 statutory deadline and a reliable grid in the near term.

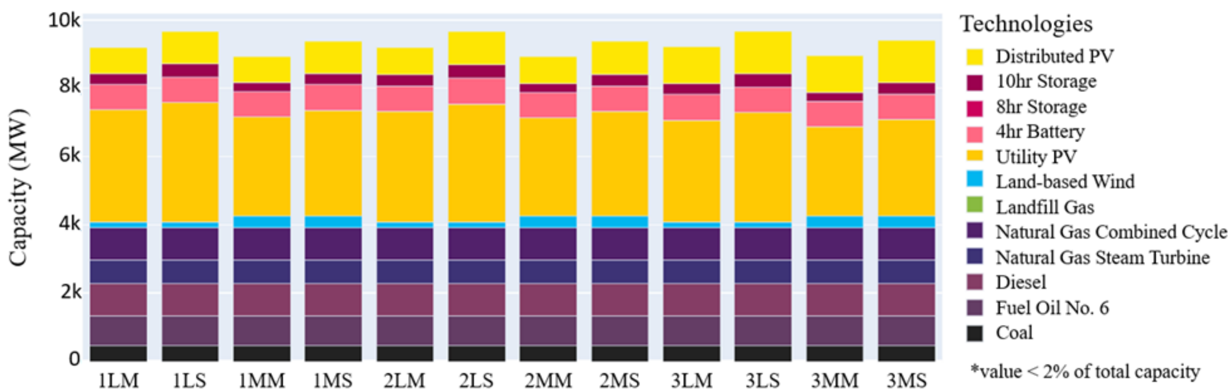


Figure ES-21. Total capacity to achieve 40% renewable energy

The scenario modeling results for 2050 (

Figure ES-22) show the generation mix on the system when 100% generation by renewables is achieved (and the system maintains the reliability requirements achieved at 40%). All fossil-fueled plants are retired by 2050. The optimal mix of resources includes the addition of energy storage and biodiesel engines to serve system energy demands during periods of low wind and solar output. Once all fossil-fueled plants are retired the system requires some biodiesel engine capacity (or a similar alternative resource) that can operate for prolonged periods. Biodiesel was chosen by the model from several flexible generation options including hydrogen because it was the lowest cost option to fill in these time periods and provide reliable capacity beyond energy storage.

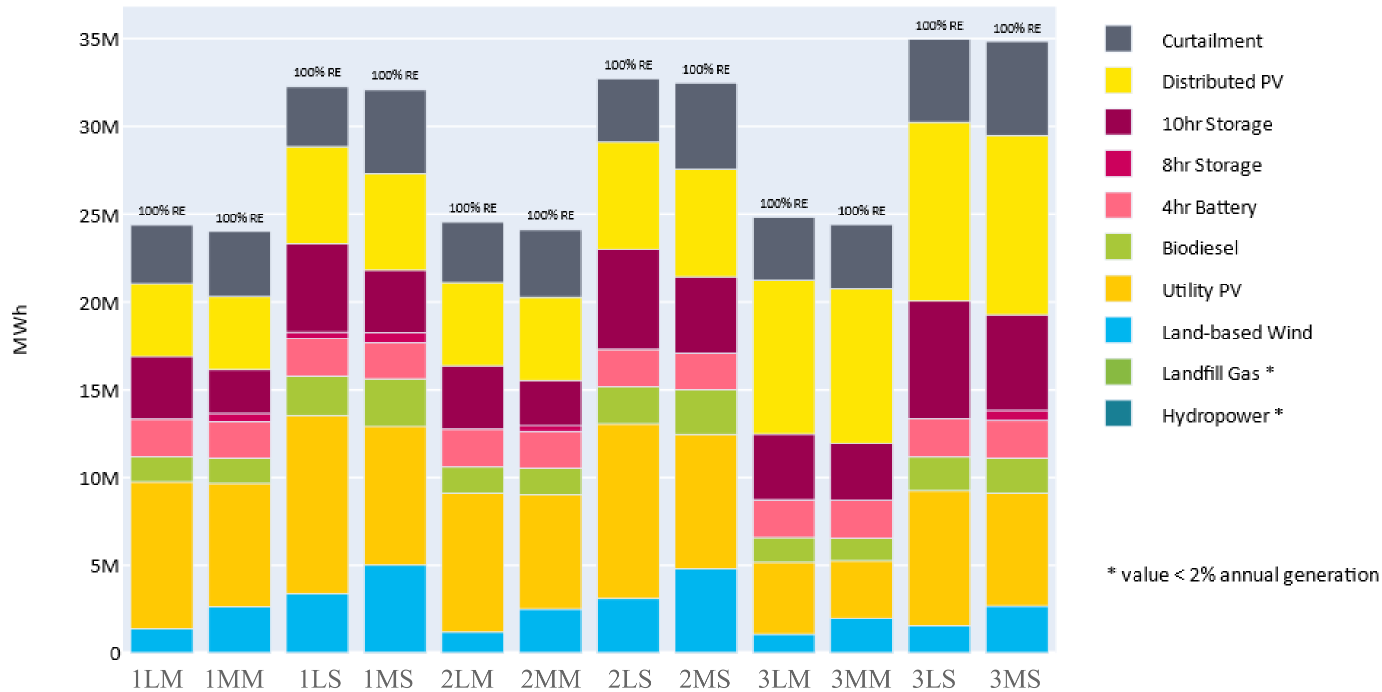


Figure ES-22. Total annual electricity generation by scenario to meet 100% renewable generation requirements for study year 2050

Despite modeling several additional technologies,[18] the results for all scenarios show a path to 100% renewable energy driven by solar PV at both the distributed and utility scales. Land-based wind is also built in all scenarios, to a smaller degree in the Less Land scenario variations than in the More Land scenario variations. Other resources were not shown to be cost- and performance-competitive. This predominance of solar, both distributed and utility-scale necessitates storage and/or flexible generation to ensure that load from residential as well as commercial and industrial customers can be met reliably. Because solar generation occurs during the day, the system needs both energy and capacity at night as well. Of the renewable resources available to build, this need is most effectively met by storage and flexible generation. Other resources, such as hydrogen storage, could be deployed to meet this need if they emerge as the least expensive options.

Several additional observations can be made about the electric system model results for 2050. First, generation levels vary greatly with load: The Mid case load scenario variations generally need less generation than the Stress loads. There is additional variation among the Stress load scenario results because some generation moves through storage systems before being used. Additionally, we observe that restricting the amount of land available for renewable energy development does constrain the amount of land-based wind capacity deployed in the Less Land scenario-variation results. Finally, curtailment of solar in 2050 is notable. The expectation is that variable sources of renewable energy are curtailed somewhat regularly to balance the system;

[18] Generation technologies included in future scenarios include distributed PV, utility-scale PV, land-based utility-scale wind, offshore wind, hydropower, landfill gas, biodiesel engines, ocean thermal energy conversion (OTEC), and hydrogen production and storage.

this is a common finding in 100% renewable energy studies and is still the least-cost system solution.

Key Findings

- To meet the near-term 40% RPS goal by 2025 as well as resource adequacy needs, the capacity expansion model's optimal solution includes multiple GW of solar and storage, and some land-based wind, by 2025.
- Across the scenarios, we do not see deployment of additional offshore wind, ocean thermal energy conversion (OTEC), or hydrogen in the model due mostly to a lack of current and projected cost-competitiveness.
- Relative costs of wind, solar, batteries, and biodiesel generators are critical drivers of the integrated capacity investment results.
- Distributed PV deployment in the future leads to some utility-scale curtailment in the model because of earlier build-out of utility PV—especially in Scenario 3—and mechanisms are needed to assess that post-2024.

Bulk Power System Operational Scheduling

This section focuses on the hour-to-hour operation of projected future bulk power systems resulting from distributed resource adoption and optimal capacity expansion. We simulated optimal scheduling of the projected bulk power system components including utility-scale generation and high-voltage transmission (38-kV and above) to meet an aggregated representation of energy demands and distributed generation to evaluate the ability of projected future energy systems for Puerto Rico to produce and transport enough electrical energy to meet electrical demand at all times. In total, we analyzed 84 years of hourly production cost model results (1 year of hourly optimal operational schedules for each capacity expansion scenario-variation and study year (2025, 2028, 2030, 2035, 2040, 2045, and 2050)).

Production cost model results indicate that with substantial changes to operational scheduling practices all projected scenario-variation systems can manage expected forecast errors to meet energy demand at all times throughout the study horizon. Even with updated scheduling practices, the lower voltage (38-kV) transmission network is found to be insufficient to support the projected system buildouts. With solar resources dominating the distributed and utility-scale generation expansions, our results show there is relatively little need for additional cross-island transmission capacity. However, the number of new generation interconnections and amount of distributed generation capacity significantly alters the flow patterns on the local transmission infrastructure that is predominantly served by 38-kV assets. Figure ES-23 (page xl) shows the total magnitude of violations simulated in each scenario and year without restricting the 38-kV transmission line flow limits. Our results show that careful generation interconnection siting, transmission expansion, and other possible mitigating actions are required to avoid frequent and debilitating 38-kV network overloads even at 40%–50% renewable energy, regardless of scenario that would limit the renewable power production capabilities of some regions.

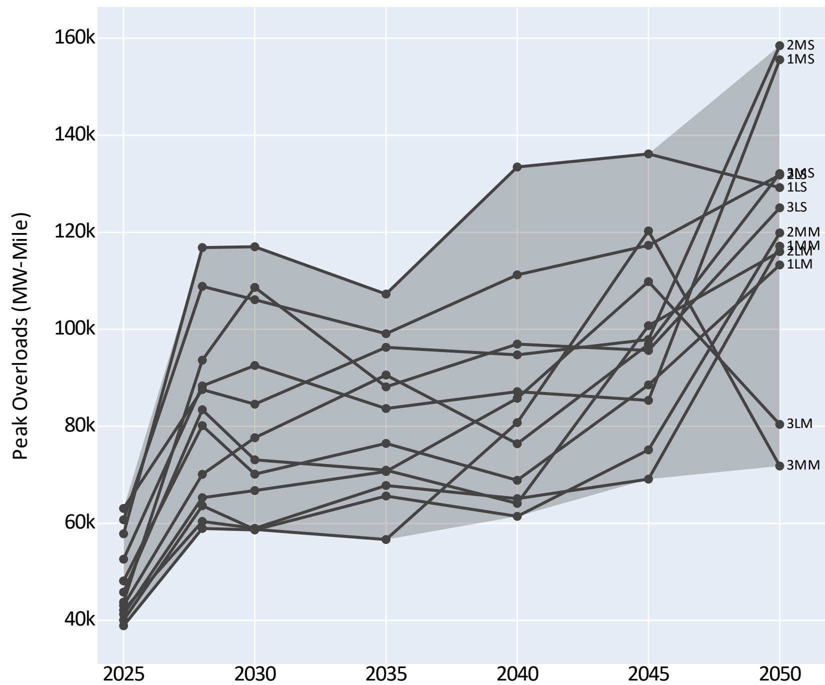


Figure ES-23. The 38-kV line overloads for 40% and 100% renewable energy

Key Findings

- The lower-voltage (38-kV) transmission network components are insufficient to handle the projected system transitions.
- The projected system build-outs have sufficient generation, storage, and transmission resources to manage forecast errors and maintain reliable service under normal operating conditions.
- While managing forecast errors will be possible, the lack of resource diversity in the projected systems will require significant operational scheduling changes to do so.

Bulk System Power Flow, Dynamic, and Resilience Impact Analysis

This section focuses on modeling and analysis of the physics of the Puerto Rico power grid to assess system reliability and resilience. The bulk power system impact analysis in PR100 comprises eight main aspects:

1. Alternating current (AC) power flow analysis to evaluate the needs for additional voltage control equipment to maintain voltages within limits and manage volage fluctuations from the variable output from distributed and utility scale renewables;
2. Grid strength analysis to identify potential need for protection system upgrades, stability concerns, and need for synchronous condensers or equivalent equipment to resolve these concerns;
3. Model tuning to improve dynamic grid models for a better baseline of analysis;

4. Electromagnetic transient (EMT) stability analysis for very near term for highest resolution modeling of renewable generation and BESS with grid supporting functions in grid-following (GFL) mode;
5. Stability analysis for 100% instantaneous penetration and grid-forming (GFM) controls in BESS and solar PV to be able to operate the system;
6. Load dynamics and DER modeling to capture interactions between DER and loads that may cause unwanted disconnections of DER potentially compromising reliability;
7. System black start using GFM battery energy storage system to begin considering replacement of fossil fuel resources that currently provide black start service; and
8. Resilience analysis to estimate possible damage to generation and T&D infrastructure from hurricane events as well as studying the ability of the future system to recover from severe hurricane damage. The corresponding eight subsections in the full report describe the methodologies, results, and considerations.

In this summary, we highlight two aspects of this analysis: grid strength and energy storage.[19] First, low grid strength is indicative of potential need for protection system upgrades and possible stability problems. As a representation metric of grid strength, Figure ES-24 shows the buses in red that are the most likely to experience stability problems and needs of protection system upgrades (as indicated by largest percentage change in short-circuit megavolt-amperes (SCMVA)). As renewable energy generation increases from 40% to 100%, high-voltage buses and legacy (fossil-fueled) generator locations show the greatest decrease in SCMVA and therefore have the least grid strength (and therefore potential stability issues and needs of protection upgrades) as the system switches to renewable energy. Remote and rural locations show little change despite having more dispersed utility-scale PV and wind in those areas. In the future, grid strength will need to be improved in areas with retired plants. Improved grid strength can help with protection coordination and avoid potential stability problems.

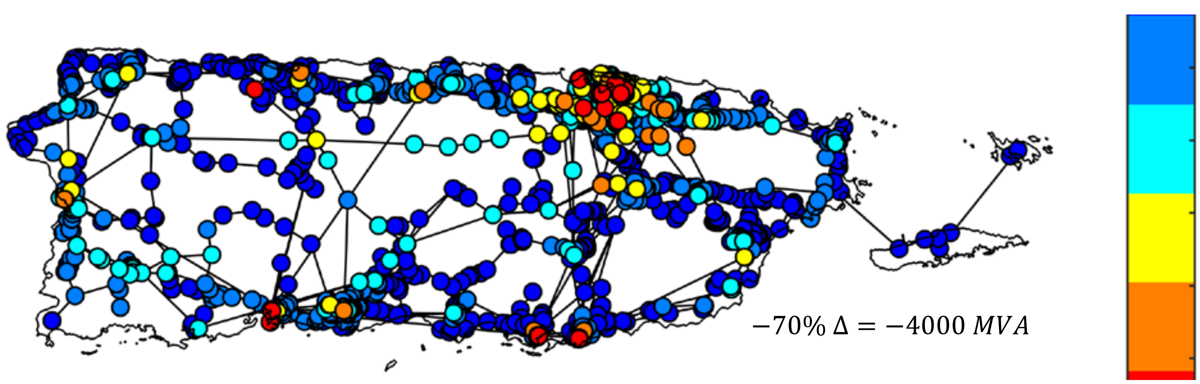


Figure ES-24. Percentage change in SCMVA from 40% to 100% renewable energy

Second, results show that installing energy storage equipped with advanced grid supporting controls will be key for improving grid reliability and resilience as Puerto Rico transitions to high levels of renewables. Grid supporting controls can include primary frequency control, automatic voltage regulation, secondary automatic generation control, GFM control, and black start. GFM inverters can establish grid voltage and frequency, including in momentary

[19]All eight aspects of this analysis are described in detail in Section 10 of the PR100 Final Report.

conditions where all resources are renewable (instantaneous 100% inverter penetration); on the other hand, grid-following inverters (currently widely used) need other resources to establish grid voltage and frequency before contributing grid support. GFM functionality will be key for reliable operation of the Puerto Rico grid with high levels of renewables.

Modeling in PR100 showed improved stability, maintaining frequency and voltages within acceptable performance after sudden generation outages, transmission faults, and undesired DER disconnections. GFM inverters are shown to be necessary for 100% instantaneous inverter penetration, and the model performed well for GFM in all BESS with fast frequency controls with 1% droop; simulations also showed that additional GFM controls in PV improves the performance further. Additionally, for system resilience, GFM inverters can contribute to black-starting the grid after hurricanes (grid-following inverters cannot provide black start services); modeling showed how a single BESS can energize the 230-kV transmission system, providing an important step for black start and system restoration. Location of energy storage systems are also very important for efficient grid recovery after hurricanes; grid recovery simulations show faster resources that can support recovery, like BESS, are available in more locations.

Key Findings

- Modeling results show that to operate the system in moments of 100% inverter conditions, advanced grid supporting functions like GFM inverters are key; in addition, synchronous condensers (1,600-megavolt-ampere [MVA] total needed to bring grid strength to about current levels) or equivalent equipment are needed to increase grid strength for adequate protection and to avoid potential stability problems.
- Results indicate that to mitigate large frequency deviations and contribute to black start and grid recovery, 300 to 800 MW of battery energy storage with GFM functionality and the ability to set up fast frequency response (1% droop) will be key for the short term. Simulations show significant stability improvement with acceptable frequency deviations for cases with 40% and 100% instantaneous inverter penetration conditions.

Distribution Grid Impacts

In PR100, we simulated impacts related to increasing amounts of distributed PV connected at the distribution system level. Distribution feeder power flow modeling was conducted on a set of representative distribution feeders from across Puerto Rico. The modeling looked at power flow, voltage, and loading impacts on feeder operation with the PV penetrations modeled under Scenarios 1, 2, and 3. It was additionally noted that some feeders, as they exist in Puerto Rico today, already operate beyond the American National Standards Institute Range A standard voltages (Kersting 2018), even with no solar PV generation, such as during nighttime periods. This was found primarily to be caused by high feeder head voltage setpoints and always-on capacitors which increased system voltage, even when voltage was already high. For this study of renewable energy impacts to distribution feeders, we assumed that these feeders were corrected to operate within American National Standards Institute Range A prior to adding any simulated PV systems. Corrections would include for the utility to change voltage setpoints and remove or replace always-on capacitors with controllable capacitors.

Figure ES-25 shows the percentage of feeders with backfeeding under Scenarios 1, 2, and 3. Backfeeding means that during midday periods there was more generation on the feeder from distributed PV than there was load consumed by customers on that feeder. Distribution systems in Puerto Rico cannot currently accommodate any backfeeding due to existing system settings which do not allow reverse power flow and which are not easily changed. To address backfeeding and other possible voltage and loading concerns from high levels of distributed PV on the distribution system, we evaluated mitigation strategies including PV grid support functions (Volt/VAR and Volt/Watt), utility-controlled storage located on the distribution feeders, and participation of customer-owned storage in a grid-interactive way (e.g., charging during midday periods). Combinations of these strategies working together were found to eliminate nearly all negative impacts of high levels of distributed PV.

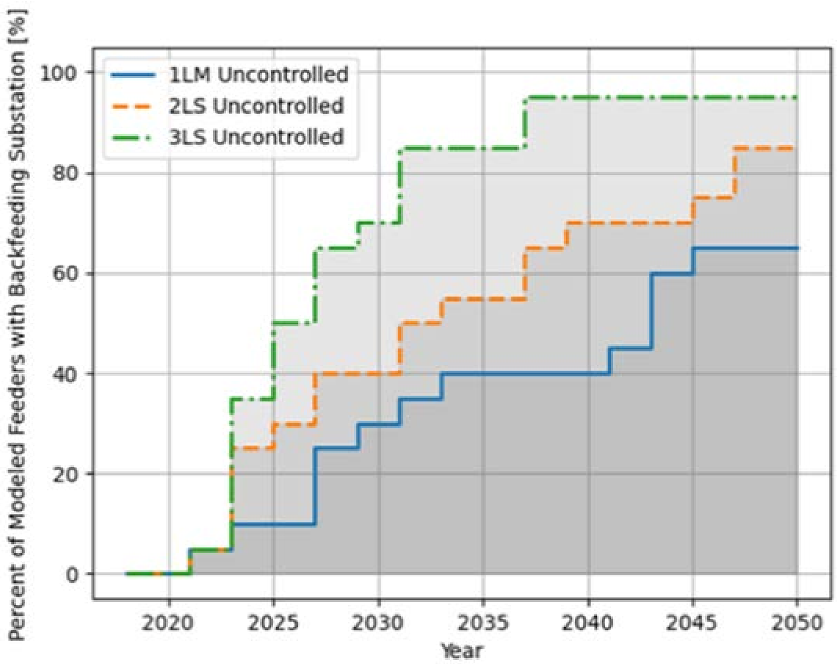


Figure ES-25. Percentage of feeders with back-feeding substations

Key Findings

- Some feeders as they exist in Puerto Rico today operate beyond the American National Standards Institute Range A standard voltages even when there is no PV power production (e.g., at night). To isolate the impact of adding renewables, these feeders were assumed to be fixed to operate within standard voltages prior to adding any simulated PV systems.
- Uncontrolled distributed PV capacity under PR100 Scenarios 1, 2, and 3 was found to exceed 65%–95% of the studied distribution feeders' hosting capacities due to issues such as backfeeding and PV-caused voltage violations.
- Combinations of mitigation strategies including utility-controlled storage, PV grid support functions, and use of customer-owned storage in a grid-interactive way were found to eliminate nearly all negative impacts of high distributed PV penetrations.

Economic Impact Analysis

We conducted an analysis of the economic impacts associated with Puerto Rico's energy transition. We employed three types of economic impact analyses to answer questions about how much the energy transition will cost the citizens and businesses of Puerto Rico, and how citizens will be financially impacted: (1) retail rate analysis, (2) gross macroeconomic impact analysis, and (3) net macroeconomic impact analysis. See the *PR100 Final Report* for a detailed discussion of all three analyses.

We found that the utility-incurred costs to transform Puerto Rico's electric grid to one that is reliable will be significant regardless of the mix of generation technologies. Because the cost variation is more meaningful over time than by scenario, we examined two scenario variations to demonstrate cost changes over time: 1LS (Scenario 1, Less Land, Stress load) and 3LS (Scenario 3, Less Land, Stress load).

Figure ES-26 shows the revenue that the utility must collect to cover its costs, known as a revenue requirement, for each scenario along with the resulting all-in average retail rate (i.e., revenue per unit of retail electric sales) over time. Despite incurring roughly similar costs regardless of the level of distributed PV adoption, the utility must charge substantially higher all-in average retail rates in Scenario 3LS (right) than Scenario 1LS (left) because the former has 20% less utility-sold electricity than the latter.

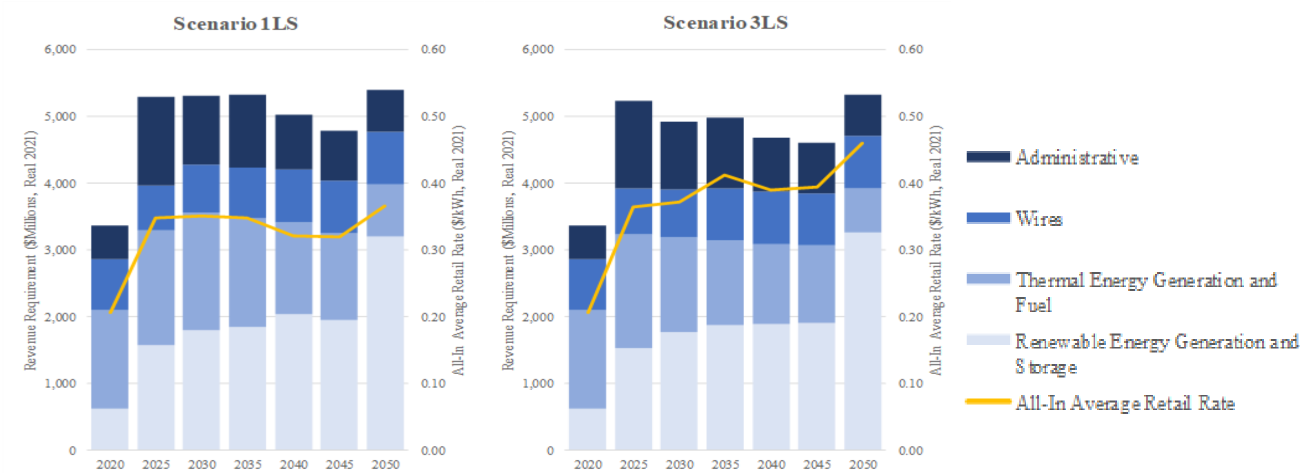


Figure ES-26. Revenue required by the utility to cover its costs for two scenario variations

Our results show that between 2020 and 2025, the large increase in utility-incurred costs was driven by three key factors: investments to achieve an adequate generation fleet, the costs of new energy efficiency programs, and PREPA's exit from bankruptcy resulting in repayment of legacy debt and pension obligations (FOMB 2023c). Importantly, as above, significant investments in generation are needed in the near term simply to achieve resource adequacy as the Commonwealth currently suffers from regular outages due to shortfalls in energy availability. Because our modeling assumes the system meets the Act 17 requirement of 40% renewable by 2025, this investment is made in renewable resources.[20] After this period, costs are relatively stable through 2025–2045 as renewable energy generation gradually replaces fossil fuel-fired generation, leading to a reduction in associated costs such as for fuel.

[20] For comparison, we ran a sensitivity that relaxed the 40% RPS requirement but still incurred generation-related investments to achieve a more reliable grid by 2025. The utility's generation-related costs as well as the overall revenue requirement were comparable to those incurred when the 40% RPS requirement was imposed.

Our results show that between 2045 and 2050, the system experiences notable cost increases that would be incurred by any system moving from already high levels of renewable energy to 100% renewable energy. This is due to the requirement to retire existing fossil fuel units and replace the firming and balancing function they perform at high levels of renewable energy (i.e., supplying energy only on an as-needed basis when renewable generation is low and storage reserves are exhausted, for example during periods with several cloudy days in a row). However, note that the costs of energy and fuels in 2050 are highly uncertain because many aspects could change during this period.

Both the cost of electricity and the investment into the electric system are important factors for Puerto Rico's economy. Our analysis examined the impact of the transition to 100% renewable energy on the economy overall, including the net impact on real household income. In the initial years of the transition (Epoch 1 in Figure ES-27), the increased investment during this time promoted expansion in the broader Puerto Rico economy but the retail rate increases eroded those gains resulting in a net decline in real household income. During the middle and end periods of the transition (Epoch 2 and Epoch 3), local investments in renewable energy and reductions in fossil fuel purchases generally lead to net increases in household income. Additional macroeconomic results, including employment impacts, can be found in the *PR100 Final Report*.

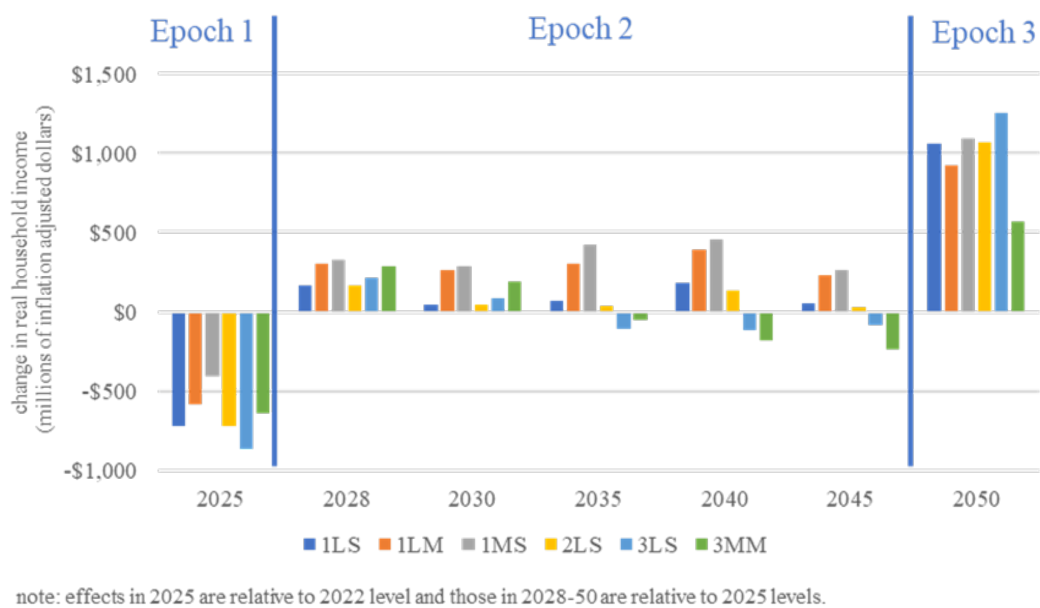


Figure ES-27. Real household income changes (millions of dollars) over scenarios for all years

Key Findings

- Modeling results showed a substantial increase in the utility's revenue requirement (48%–57%) between 2020 and 2025 to achieve a more reliable and stable energy system that also met the 40% renewable energy RPS requirement, resulting in large all-in average retail rate growth (66%–83%).
- Between 2025 and 2045, the utility experienced a decline in its revenue requirement (9%–24%) which when combined with the positive macroeconomic benefits from investments and expenditures in renewable energy resulted in increases in real household income.
- To fully achieve the 100% RPS requirement between 2045 and 2050, the utility experienced an increase in its revenue requirement (4%–16%), resulting in modest average retail rate growth (11%–17%).
- Increases in retail rates adversely affect the bills of nonadopters of rooftop PV.
- Very low-income households (earning $15K/year or less) were particularly vulnerable to large retail rate increases, especially if they were more likely to be nonadopters of rooftop PV, resulting in energy justice implications

Implementation Actions

In the PR100 Implementation Roadmap ("Roadmap"), we identify implementation actions stakeholders can take to progress toward a more robust, reliable, renewable, resilient, and equitable energy system for Puerto Rico. These actions are based on the results of our analysis in PR100, observations about Puerto Rico's current energy system made while performing the PR100 analysis, and our knowledge of industry best practices. Actions are highlighted throughout the *PR100 Final Report* and are aggregated and discussed in the Roadmap. Here we summarize high-level action items which are combinations of multiple specific actions listed in the Roadmap. For the full Roadmap, which contains more details on these action items, see Section 17 (page 590).

Here and in the Roadmap, we organize implementation actions into the following temporal phases, shown in Figure ES-28:

- *Immediate actions* to build a more robust electric system and lay the foundation for high levels of renewable energy
- *Near-term* actions to achieve 40% renewable energy while moving toward industry accepted system performance and increasing resilience
- *Mid-term* actions to achieve 60% renewable energy to gain operating experience and be adaptive in system design
- *Long-term* actions on the road to 100% renewable energy where effective deployment and operation of the complex system is achieved
- *Recurring actions* to continually maintain and improve the system and associated planning processes.

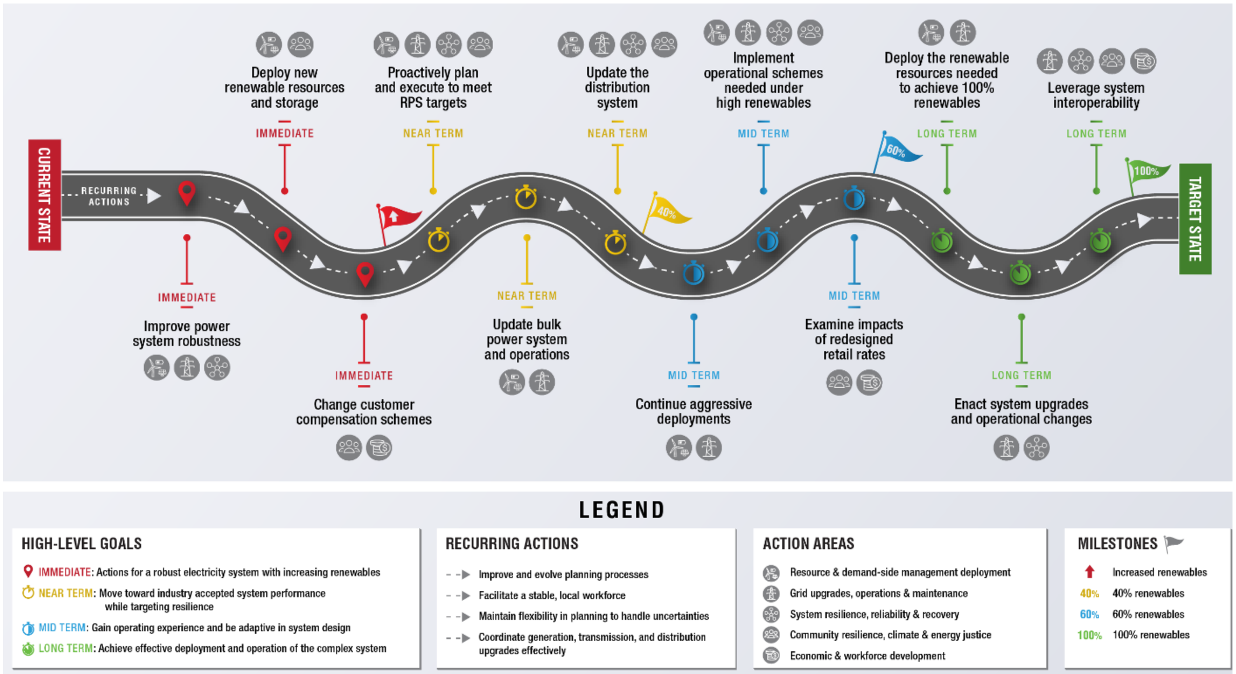


Figure ES-28. The temporal organization of the PR100 Implementation Roadmap

Actions are additionally categorized by topic areas ("action areas") and stakeholder groups to organize the actions and to help identify responsible parties for executing each action. Action areas and their associated icons are shown in Figure ES-29.

Figure ES-29. Implementation Roadmap action areas

The four stakeholder groups identified in the Roadmap as having a role to play in the implementation of Puerto Rico's energy future are:

- Utility and grid operators
- Renewable developers
- Energy regulators
- Customers and communities.

Immediate Actions for a Robust Electric System With Increasing Renewables

PR100 results across all scenarios indicate that increased capacity is needed immediately to achieve a robust electric system. New renewable resources will both increase system capacity and contribute to Puerto Rico's near-term goal of 40% renewable energy. Table ES-1 describes the immediate implementation actions identified in PR100. These actions could be undertaken right away to help position the electric system to achieve a future state that will increase system robustness and enable integration of a high level of renewable energy.

Table ES-1. Immediate Actions Identified by PR100

High-Level Actions	Action Areas	Stakeholders
Improve power system robustness by increasing capacity and making urgent repairs		✓ Utility and Grid Operators ✓ Renewable Developers ✓ Energy Regulators
Deploy new resources and storage via stakeholder-driven pathways		✓ Utility and Grid Operators ✓ Renewable Developers ✓ Customers and Communities
Change customer compensation schemes to incentivize temporal-based charging and discharging among stakeholders		✓ Utility and Grid Operators ✓ Energy Regulators

Rationale for Actions

Improve power system robustness by increasing capacity and making urgent repairs

The power system in Puerto Rico requires immediate upgrades to improve performance to acceptable levels. The power system is considered fragile across all levels—generation, transmission, and distribution systems—which manifests as poor reliability, inefficient operations, and vulnerability to extreme weather events and other natural hazards (e.g., hurricanes, floods, and earthquakes). There is an immediate need to make the system robust by building new capacity and updating transmission and distribution system operations, controls, and hardware, as legacy infrastructure is reconstructed and new resources are deployed.

Deploy new resources and storage via stakeholder-driven pathways

PR100 results confirm an immediate need for new resources on the current system to stabilize the grid and alleviate current generation shortfalls, including rapid deployment of utility-scale and distributed renewable resources and significant amounts of storage to address current system issues and contribute to the near-term Act 17 goals. Consider stakeholder priorities and concerns and follow stakeholder-driven pathways to enable the accelerated deployment needed to overcome generation capacity shortfalls and meet Act 17 goals.

Change customer compensation schemes to incentivize temporal-based charging and discharging among stakeholders

PR100 results point to long-term impacts of current customer compensation in Puerto Rico. Specifically, there is no incentive for customers to use their batteries in a grid-interactive fashion, and there can be equity concerns around electric rates paid by those customers who own distributed energy systems versus those that do not. To stave off near-term distribution hosting capacity concerns and long-term rate concerns, there is an immediate need to incentivize temporal-based charging and discharging of customer-owner storage systems to increase hosting capacity and better align compensation for customer generation with its value to grid operations. The Battery Emergency Demand Response Program piloted by LUMA is an initial effort that can be leveraged and built upon to address this immediate action (LUMA 2023c).

Near Term: Move Toward Industry Accepted System Performance While Targeting Resilience (Transitioning to 40% Renewables)

In the near term, the primary goal is to improve the system performance to an industry accepted level while targeting resilience. Listed in Table ES-2 are actions directly supported by PR100 findings which can help achieve the near-term phase of implementation, which is to reach 40% renewable energy generation.

Table ES-2. Near-Term Actions Identified by PR100

High-Level Actions	Action Areas	Stakeholders
Proactively plan and execute to meet RPS targets, including installing multiple GW of renewable resources and storage and rapidly designing and implementing energy efficiency to achieve Act 17 goals.		✓ Utility and Grid Operators ✓ Energy Regulators ✓ Renewable Developers ✓ Customers and Communities
Update bulk power system and operations: establish updated operational strategies, establish requirements for grid-forming inverters, study and upgrade lower voltage (38-kV) transmission network, plan for future renewable penetrations, and deploy storage.		✓ Utility and Grid Operators ✓ Renewable Developers ✓ Energy Regulators
Update the distribution system: upgrade control schemes including voltage regulation, deploy storage at critical points, and prioritize upgrades on vulnerable feeders.		✓ Utility and Grid Operators ✓ Energy Regulators ✓ Customers and Communities

Rationale for Actions

Proactively plan and execute to meet RPS targets

Across all scenarios, significant deployment is immediately necessary to achieve 40% renewable energy. Several resource deployment activities are already underway, including procurement tranches for implementation of the 2019 IRP (PREB 2020) at the utility scale and actions through the Puerto Rico Energy Resilience Fund, [21] which incentivizes distributed solar and

[21] "Puerto Rico Energy Resilience Fund," DOE Grid Deployment Office. https://www.energy.gov/gdo/puerto-rico-energy-resilience-fund

storage for very low-income households and households that include a family member with an energy-dependent disability.

Re-evaluation of the RPS in Act 17 may be needed, in alignment with a proposed regulation from the Puerto Rico Energy Bureau (PREB) regarding regulation of renewable energy certificates compliance with the RPS, which would establish annual targets starting in 2024 and procedures and penalties for noncompliance (PREB 2023a). Actions to consider in re-evaluation include adding more interim targets to keep deployment on schedule, setting goals in energy (MWh) to match procurement requirements, providing clear guidance on renewable energy certificates to include the measurement of distributed PV in RPS requirements, and clearly defining impacts for missing RPS targets to increase accountability.

Update bulk power system and operations

As highlighted in Figure ES-23 (page xl), action is necessary to mitigate the modeled level of low-voltage transmission overloads on the 38-kV network which will emerge with more renewables. This could require various enhancements from non-wires alternatives, reactive power support solutions, installing new renewable resources and storage at optimal locations to mitigate the violations, and additional lines to improve current management. A detailed modeling study of the 38-kV system to identify specific investments could be conducted by LUMA as part of the IRP process or as a standalone effort. Additional efforts to update the operational strategies and forecasting techniques can also be made to prepare for a system with high renewable penetration.

PR100 has also identified that storage will play a key role in supporting the energy transition and mitigating several issues on the grid in the near term. Deploying utility-scale storage with advanced controls on both the transmission and distribution grid in the near term can eliminate voltage and reliability issues experienced under high renewable scenarios. Larger storage systems are also important for occasional multiday discharges. Utilizing distributed storage to support the grid, including during outages, is also critical.

Update the distribution system

Starting the process immediately to improve hosting capacity generally is important as distribution system hosting capacity needs to be increased to accommodate accelerating deployment of rooftop solar. Inverter controls could help increase that capacity, as could improvements to distribution infrastructure and deployment of utility-controlled battery storage on feeder lines. Additionally, transparent and up-to-date data about hosting capacity from the utility is crucial for continued solar adoption.

Best Practices

In addition to the action items directly supported by PR100 findings listed in Table ES-2, several action items to follow best practices were indicated directly or indirectly by PR100 findings. Resilience will be a key focus in the near term as renewable energy penetration can allow for increased resilience if operated effectively, such as utilization for black start and microgrid adoption. To support resilience, rooftop PV systems could be integrated into microgrids. To support blue-sky operations, virtual power plants can be operated. Additional sensing across distribution and transmission systems will support identification of outages and problem areas and will enhance modeling and simulation efforts.

Mid-Term: Gain Operating Experience and Be Adaptive in System Design (Operating With 40%–60% Renewables)

The primary goal in the mid term is for stakeholders to gain operating experience and be adaptive in system design as future uncertainties are realized. Actions inspired by PR100 which support the implementation phase from 40% to 60% renewable energy are shown in Table ES-3.

Table ES-3. Mid-Term Actions Identified by PR100

High-Level Actions	Action Areas	Stakeholders
Continue aggressive deployment of renewable resources including significant amounts of storage.		✓ Utility and Grid Operators ✓ Energy Regulators ✓ Renewable Developers ✓ Customers and Communities
Implement operation schemes needed under high penetrations of renewables including advanced forecasting, operating reserves, and protection coordination schemes.		✓ Utility and Grid Operators ✓ Customers and Communities
Examine impacts of redesigned retail rates and distributed generation compensation schemes and modify as needed to achieve efficient system operation and support equitable solution.		✓ Utility and Grid Operators ✓ Renewable Developers

Rationale for Actions

Continue aggressive deployment of renewable resources

Continuing to deploy renewables at an aggressive pace is expected to promote a smooth buildout across all timescales. Particularly important during the mid term will be installing and utilizing storage. Larger storage systems become important during the mid term, as occasional multiday lulls in renewable resource generation (e.g., multiple cloudy days in a row) can cause disruptions to power supply at the penetrations seen in the mid term. Additionally, distributed storage to support the grid, including during outages, remains very important during the mid term. Installing storage and renewable generation with grid-supportive controls will help overcome new challenges to system stability. An additional consideration that becomes important in the mid term is to spread generation across the territory to avoid large impacts from single-point failures.

Implement operation schemes needed under high penetrations

In the mid term and extending into the long term, it will become important to update and test procedures for operating reserves and scheduling to operate the system as it becomes more complex due to the addition of variable renewable generation. Part of this will be implementing advanced forecasting and dispatch technologies to inform battery charging and discharging cycles, and to control loads via demand response as applicable. There will be a need to perform studies to identify the correct protection coordination concerns such as reverse power flow and line overloading on both distribution and lower-voltage transmission networks as the renewable penetration increases.

Examine impacts of redesigned retail rates

By the mid term, there will be a significant amount of customer-owned generation under all PR100 scenarios. In the mid term, as the number of customers who own generation is of the same magnitude as those who do not, it will become critical to assess electric rate equity concerns. Under net metering as it exists today, PR100 results show that rates for customer electrical service will increase in the long term, and that lower income households are especially vulnerable to higher electricity prices. Lower income households may also have a more difficult time adopting rooftop PV and storage due to higher up-front costs and lack of access to financing. Ongoing efforts to provide equitable access to participate in the energy transition will ease these effects on lower income residents.

Best Practices

Inspired by the findings of PR100, in the mid term a best practice is for stakeholders to gain experience with new renewable energy technologies. Operators can deploy small and mid-scale emerging and resilient resources such as long duration storage, dispatchable renewables, and other currently unknown solutions to gain foundational knowledge of their operation and prepare for their large-scale deployment in the long term. Included in this will be an opportunity to identify and evaluate different dispatchable renewable energy solutions. At this mid-term stage, it will additionally be prudent to adapt to advances in renewable energy technology, changes in relative costs between different renewable energy types, and climate changes altering resources and threats.

Long-Term: Achieve Effective Deployment and Operation of the Complex System (Approaching 100% Renewables)

The primary goals in the long-term are to achieve effective deployment and efficiently operate the complex system as it approaches 100% renewables. Uncertainty in the later years is inherent in any study looking out several decades. There are likely to be changes in technology availability (e.g., long-duration storage), resource capital costs, network topology, and other key factors. Detailed in Table ES-4 are considerations from the study that are relevant to the final phase from 60% to 100% renewable energy generation.

Table ES-4. Long-Term Actions Identified by PR100

High-Level Actions	Action Areas	Stakeholders
Deploy the renewable resources needed to achieve 100% penetrations, including implementing long-duration storage and dispatchable renewable resources.		✓ Utility and Grid Operators ✓ Renewable Developers ✓ Energy Regulators ✓ Customers and Communities
Enact system upgrades and operational changes to mitigate congestion issues from high-penetration renewable system with dispersed generation; enable black start and recovery capabilities of all assets via GFM controls.		✓ Utility and Grid Operators ✓ Renewable Developers ✓ Energy Regulators
Leverage system interoperability between loads such as increased electric vehicle adoptions and variable generation using advanced forecasting, dynamic rates, and export compensation schemes.		✓ Utility and Grid Operators ✓ Energy Regulators ✓ Customers and Communities

Rationale for Actions

Deploy the renewable resources needed to achieve 100% penetrations

To achieve 100% penetration, significant installations of mature and currently emerging technologies will be required. Deployment of utility-scale PV, distributed PV, wind generation, storage technologies, and dispatchable renewable resources are all required in the long term. PR100 identified the need for over 1,300 MW of biodiesel generation (or other equivalent "firm" generation), a dispatchable asset which provides flexibility for the highly renewable system. The study also found that distributed PV deployment is an essential building block towards reaching 100% penetrations and is especially needed to overcome many of the resilience challenges that Puerto Rico's grid could face; scenarios with more rooftop PV enabled much faster recovery than those with more centralized generation.

Enact system upgrades and operational changes

Substantial grid upgrades are required to accommodate the future resource mix. The future grid will require buildout of new protection equipment, transmission and distribution infrastructure, sensing, and more. The transmission system can be strengthened by enhancing distribution system management to accommodate very high distributed PV penetrations and deploying synchronous condensers. On the distribution system, battery storage capacities of up to 2x installed distributed PV capacities will be needed, though storage needs can be reduced if customer-owned storage is used interactively with grid operations. On the transmission system, the study identified a need for 1,600 MVA total capacity of synchronous condensers in eight locations to enable 100% renewable scenarios. Additionally, advanced forecasting and dispatch technologies will need to be capable of operating the energy system in the long term. Implementing black start and recovery capabilities via GFM controls can support full-scale combined use of energy storage, renewables, and microgrids to black start the entire Puerto Rico energy system.

Leverage system interoperability

In the long term, electric vehicle adoptions are projected to increase total system load by about 15% and can have a higher instantaneous contribution. Electric vehicle loads are projected to increase the nighttime system peak load while large amounts of PV generation will decrease the system daytime minimum load. This will require efficient operation and deployment of long-duration storage and dispatchable renewable generation. However, this also presents the opportunity to integrate controllable loads into system operations. Controllable loads including EVs can help consume load when generation is plentiful and can limit consumption when generation is scarce. This will help reduce storage capacity needs and congestion concerns.

Best Practices

Climate change and other evolving factors will affect management, operation, and maintenance of the energy system. This is particularly true in the long term, as future work on end-of-century climate projections may point to increasing impacts currently not captured by mid-century climate models. Utilities can mitigate these impacts by integrating climate awareness into grid planning processes and day-to-day utility operations. Adaptable disaster plans and resilience goals can evolve with the hazard landscape.

Recurring Actions: Continually Maintain the System and Improve Planning Processes

In addition to near-, mid-, and long-term action items, we identified several recurring actions for stakeholders to take throughout the energy transition, detailed in Table ES-5. Many of the recurring actions are not technical findings of PR100, but are best practices noted through stakeholder engagement and energy justice analysis conducted as part of PR100.

Table ES-5. Recurring Actions Identified by PR100

High-Level Actions	Action Areas	Stakeholders
Improve and evolve planning processes: Identify and pursue stakeholder-informed pathways for deploying new resources and storage, including consideration of land use and local resilience benefits.		✓ Utility and Grid Operators ✓ Renewable Developers ✓ Energy Regulators ✓ Customers and Communities
Facilitate a stable, local workforce to support installation, operations, and maintenance of the system across the entire planning horizon.		✓ Utility and Grid Operators ✓ Customers and Communities

Rationale for Actions

Improve and evolve planning processes

A key recurring action for stakeholders to consider is to continually improve and evolve grid planning processes. Involving a breadth of stakeholders to develop and implement meaningful processes for engaging communities, assessing potential impact, and interpreting land use policy can support deployment of large-scale renewable energy projects. Developing structures and processes that foster community and industry sector participation and take into consideration their unique and common perspectives can ensure broad and meaningful stakeholder participation in planning, decision-making, and implementation of Puerto Rico's energy future. Continually evaluating local resilience benefits, such as microgrids, will improve the resilience planning efforts across all time periods. Overall, this can help support a just and inclusive energy transition for Puerto Rico.

Facilitate a stable, local workforce

Developing and expanding job training and education programs could help prepare the Puerto Rico workforce to meet the estimated 25,000 jobs required for the transition to 100% renewables. Supporting workforce training within Puerto Rico has benefits for household and territory-wide economics, and for public knowledge and participation in energy system development. Other efforts to educate about the Puerto Rico energy system and energy efficiency programs are similarly useful for citizens.

Best Practices

There are likely to be changes in technology maturity (e.g., long-duration storage), resource capital costs, policies, and other key uncertainties as the system approaches 100%. This uncertainty is a reminder to maintain some flexibility in planning to be able to adjust as the future unfolds. Additionally, ensuring that grid planning processes and subsequent investment decisions are coordinated across the generation, transmission, and distribution systems will ensure a diversified energy mix at the least-cost options while addressing stakeholder priorities and system needs over the long planning horizon.

Conclusion

Achieving a robust, affordable, resilient, and equitable energy system for Puerto Rico powered by 100% renewable energy will not be fast or easy, but it is possible. The *PR100 Final Report* and website provides stakeholders in Puerto Rico a detailed set of results and an unprecedented view into the current energy system and possibilities for the future based on in-depth modeling and analysis. Deep engagement with members of our Advisory Group, Steering Committee, industry sectors, and communities across Puerto Rico by the PR100 project team informed our understanding of the experiences and priorities that motivate the people who are affected by and who will shape the energy system of the future. As we conducted the study, the landscape of energy policy, programs, projects, funding, incentives, costs, and other market factors continued to shift, including as Hurricane Fiona caused a systemwide blackout and frequent outages disrupted daily life.

Residential, commercial, and industrial customers in Puerto Rico have adopted rooftop solar and storage at a very fast pace in recent years. The role of electric cooperatives and community-based projects is expanding, and the level of interest in the energy transition across Puerto Rico is truly inspiring, though not surprising considering these topics are top of mind due to the widespread and devastating effects of past disruptions. It is an exciting time for the people of Puerto Rico to stand up and say what they want and do not want from the energy system of the future, and to contribute to the decisions that will affect their lives. As PR100 is now concluded, it is up to decision makers to review the study results, evaluate trade-offs, and implement decisions to improve the energy system now and prepare for the transition to a reliable, resilient 100% renewable energy future.

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1 Introduction

Puerto Rico's electric system is a complex, isolated system that depends on imported fuels and is vulnerable to extreme events. Decades of operational, maintenance, and financial challenges have resulted in a system that lags far behind national standards. In 2021, the average utility customer in Puerto Rico lost power 7.8 times, whereas the number of outages the average customer in the 50 U.S. states experienced was 1.1 (FOMB 2023b). Yet, electricity rates in Puerto Rico averaged $0.25/kWh for residential customers as of August 2023 (EIA 2023c),[22] which is notably higher than in the 50 U.S. states ($0.16/kWh) but not as high as in Hawaii ($0.39/kWh) (EIA 2023b). And Puerto Rico experienced one of the longest power outages in U.S. history after Hurricane Maria in 2017, which caused billions of dollars in damages and led to nearly 3,000 excess deaths by one estimation (Santos-Burgoa et al. 2018) or more than 4,500 by another (Kishore et al. 2018). Then in September 2022, Hurricane Fiona again knocked out 100% of the grid for as long as 4 weeks in parts of Puerto Rico (LUMA 2022b).

In 2019, the Puerto Rico legislature passed the Puerto Rico Energy Public Policy Act (Act 17) (Puerto Rico Legislative Assembly 2019), setting a goal for the Commonwealth to meet 100% of its electricity needs with renewable energy by 2050 and including interim targets of 40% by 2025, 60% by 2040, the phaseout of coal-fired generation by 2028, and a 30% improvement in energy efficiency by 2040.[23] Yet, energy system recovery, efforts to increase resilience, and progress toward these targets have been slow. With 3%–5% renewable energy on the grid by mid-2023, and total utility-scale renewable energy capacity of 226 MW as of October 2023, ≈137 MW of which is utility-scale solar photovoltaics (PV) (LUMA 2023d), achieving the 40% target by 2025 would represent an increase of at least 3 GW of additional renewable energy capacity if met with utility-scale solar (Section 8, page 209). Although the procurement of utility-scale renewable energy has been slow, the pace of distributed solar PV adoption is accelerating, increasing from 228 MW of total installed generation capacity in June 2021 to 680 MW in October 2023 (LUMA 2023d), a threefold increase in just over two years.

Since hurricanes Irma and Maria in 2017, the U.S. Department of Energy (DOE) and six DOE national laboratories have provided Puerto Rico energy system stakeholders with tools, training, and modeling support to enable planning and operation of the electric system with more resilience against further disruptions. A memorandum of understanding among DOE, the U.S. Department of Homeland Security, the U.S. Department of Housing and Urban Development (HUD), and the Commonwealth of Puerto Rico signed in February 2022 (DOE 2022b) enhanced collaboration among federal agencies and the Commonwealth. A memorandum of understanding among DOE, the U.S. Department of Homeland Security, the U.S. Department of Housing and Urban Development (HUD), and the Commonwealth of Puerto Rico signed in February 2022 (DOE

[22] According to the U.S. Energy Information Administration (EIA) 12-month rolling average through August 2023, residential customers paid $0.25/kWh in Puerto Rico and $0.16/kWh in the 50 U.S. states (commercial: $0.27/kWh in Puerto Rico and $0.13/kWh in the states; industrial: $0.26/kWh in Puerto Rico and $0.08/kWh in the states).
[23] Renewable energy is defined in Puerto Rico public policy as (1) "solar energy; wind energy; geothermal energy; renewable biomass combustion; renewable biomass gas combustion; combustion of biofuel derived solely from renewable biomass; hydropower; marine and hydrokinetic renewable energy, and ocean thermal energy" in the Public Policy on Energy Diversification by Means of Sustainable and Alternative Renewable Energy in Puerto Rico Act (Act 82) (Puerto Rico Legislative Assembly 2010) and as (2) "…any other not derived from fossil fuels, or solid waste conversion or incineration" in the Puerto Rico Climate Change Mitigation, Adaptation, and Resilience Act (Act 33) (Puerto Rico Legislative Assembly 2019b).

2022b) enhanced collaboration among federal agencies and the Commonwealth. Impacts of Hurricane Fiona on the Puerto Rico energy system in 2022 led to a renewed commitment from the Biden administration to accelerate the process of helping the Commonwealth build a more resilient grid, including the creation of the Puerto Rico Grid Modernization and Recovery Team.

As part of ongoing support to ensure recovery activities are aligned with Puerto Rico's renewable energy goals, in 2022 DOE and FEMA launched PR100, a study led by the National Renewable Energy Laboratory (NREL) with contributions from Argonne National Laboratory, Lawrence Berkeley National Laboratory, Oak Ridge National Laboratory, Pacific Northwest National Laboratory, and Sandia National Laboratories. PR100 was an integrated effort drawing on expertise and capabilities of the contributing national laboratories that explored possible pathways for Puerto Rico to reach its goal of 100% renewable energy in the long term (by 2050), increase reliability and resilience in the immediate term (within the next few years), and work toward energy justice. The purpose of the study is to provide decision support and inform investment decisions for implementers of Puerto Rico's energy transition.

1.1 Study Overview

The robust and objective energy analysis of PR100 entailed five activities (Figure 1, page 4), which were organized into 11 tasks (Figure 2, page 5) and were completed from January 2022 through December 2023 (Figure 3, page 6). Work conducted from January through December 2022 is referred to as Year 1 work, and work from January through December 2023 is referred to as Year 2 work.

This report, which was released at the conclusion of Year 2 of PR100, follows interim publication in July 2022 of the *PR100 Six-Month Progress Update* (NREL 2022c) and January 2023 of the *PR100 One-Year Progress Update Summary Report* (Blair et al. 2023), as well as public webinars in February 2022 to kick off the study and in July 2022 and January 2023 to present and engage with stakeholders on content from the interim publications. Nearly all publications and public events associated with the study are available in Spanish and English.[24]

[24] All PR100 publications are available from "Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study (PR100)," DOE, https://www.energy.gov/gdo/puerto-rico-grid-resilience-and-transitions-100-renewable-energy-study-pr100. These and additional resources are available from "Multilab Energy Planning Support for Puerto Rico," NREL, https://www.nrel.gov/state-local-tribal/multi-lab-planning-support-puerto-rico.html.

1.1.1 Year 1 Activities

In Year 1, we convened an Advisory Group of stakeholders with whom we engaged for the duration of the study to provide input on (1) methods and results throughout PR100 and (2) DOE's portfolio of energy planning support and responsive technical assistance for Puerto Rico. Engaging with the Advisory Group is one way we grounded the study in principles of energy justice, by creating an opportunity for a cross-section of energy system stakeholders to have their voices heard and their priorities reflected. This approach is consistent with procedural justice, which "concerns who is at the decision-making table, and whether, once at the table, everyone's voice is heard" (Baker, DeVar, and Prakash 2019). We worked with Advisory Group members to define four initial scenarios, or possible pathways, to achieve Puerto Rico's renewable energy goals and increase the resilience and reliability of the energy system. We gathered data about the technical potential of renewable energy resources in Puerto Rico, the cost of technologies, and areas of land and sea available for renewable energy development.

Also in Year 1, we conducted analysis to understand the potential of wind resources, made projections of future electricity demand including factors such as adoption of electric vehicles (EVs) and energy efficiency measures, and modeled adoption of distributed solar and storage. We conducted an initial round of capacity expansion modeling of the four scenarios—Economic, Critical, Equitable, and Maximum—to understand, based on established constraints, the optimal mix of energy technologies by year through 2050, as well as resource adequacy. We did preliminary work to prepare for analysis in Year 2 of the effects on the transmission and distribution system, as well as the economic and resilience impacts, of each modeled scenario. Finally, we began a climate risk assessment to consider impacts of sea level rise and other effects of climate change on the future of Puerto Rico's energy system.

1.1.2 Year 2 Activities

In Year 2, we combined Scenario 1 (Economic) and Scenario 2 (Critical) based on the Year 1 finding that Scenario 1 contained critical services that would have been included in Scenario 2, reducing the number of scenarios in the study from four to three. We analyzed the impact of the modeled scenarios on the transmission system, including its resilience to future disruptions. We studied impacts to the distribution system and related considerations such as microgrids. Economic impact analysis yielded potential effects on retail rates, including metrics related to changes in household income by income group under each scenario.

Also in Year 2, we partnered with researchers in the University of Puerto Rico at Mayagüez (UPRM) Department of Electrical and Computer Engineering[25] to contribute to the study by (1) providing technical review and consultation on scenario definition, energy justice, and resilience metrics and analyses and (2) collecting and analyzing data. In addition to continuing to hold regular meetings with the Advisory Group, we conducted a PR100 Community Engagement Tour to connect with communities across Puerto Rico about the study and request input on considerations for implementers and energy justice priorities. All analysis results were evaluated through an energy justice lens to understand benefits and burdens of the energy system experienced by various stakeholder groups. We updated the study scope in Year 2 based on Year 1 results and stakeholder input. A summary of Year 2 scope updates is in Table 1 (page 7).

[25] ece.uprm.edu

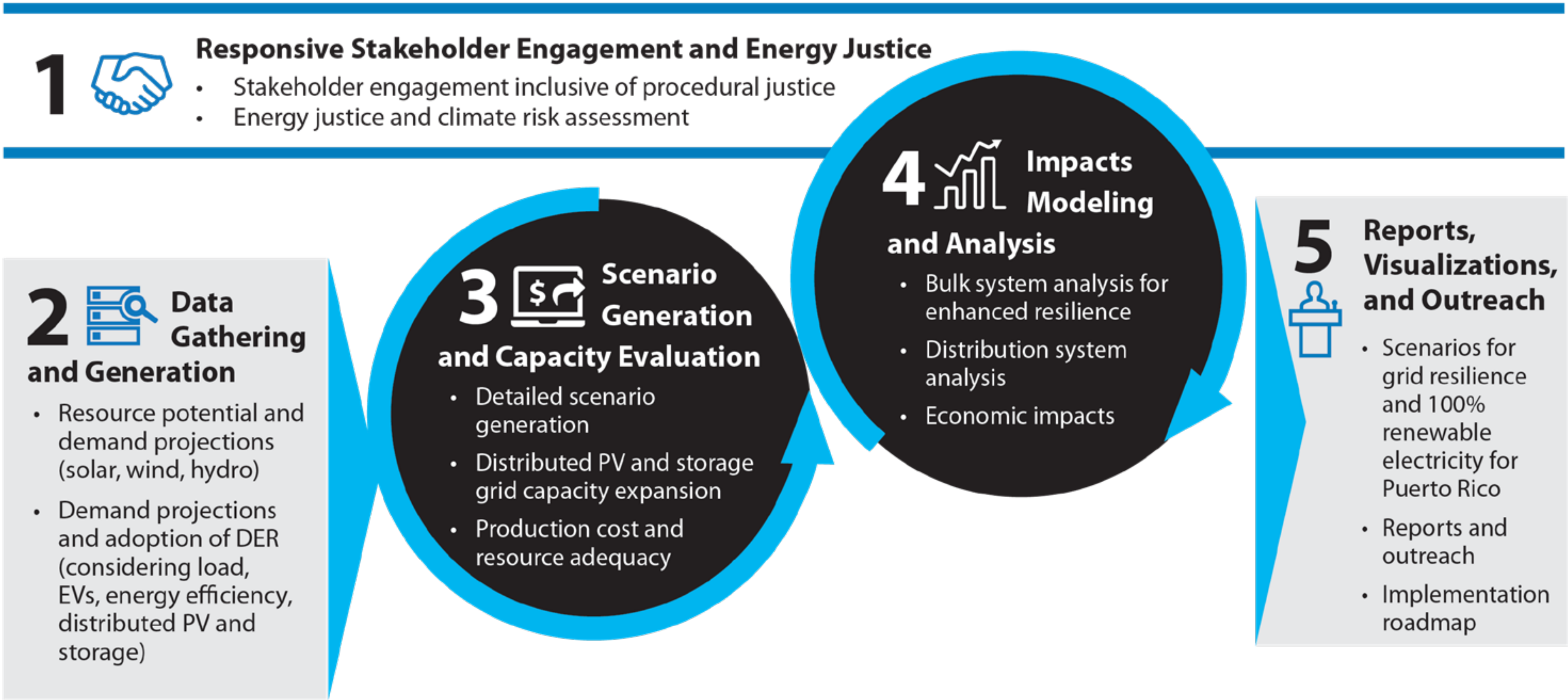

Figure 1. PR100 activities

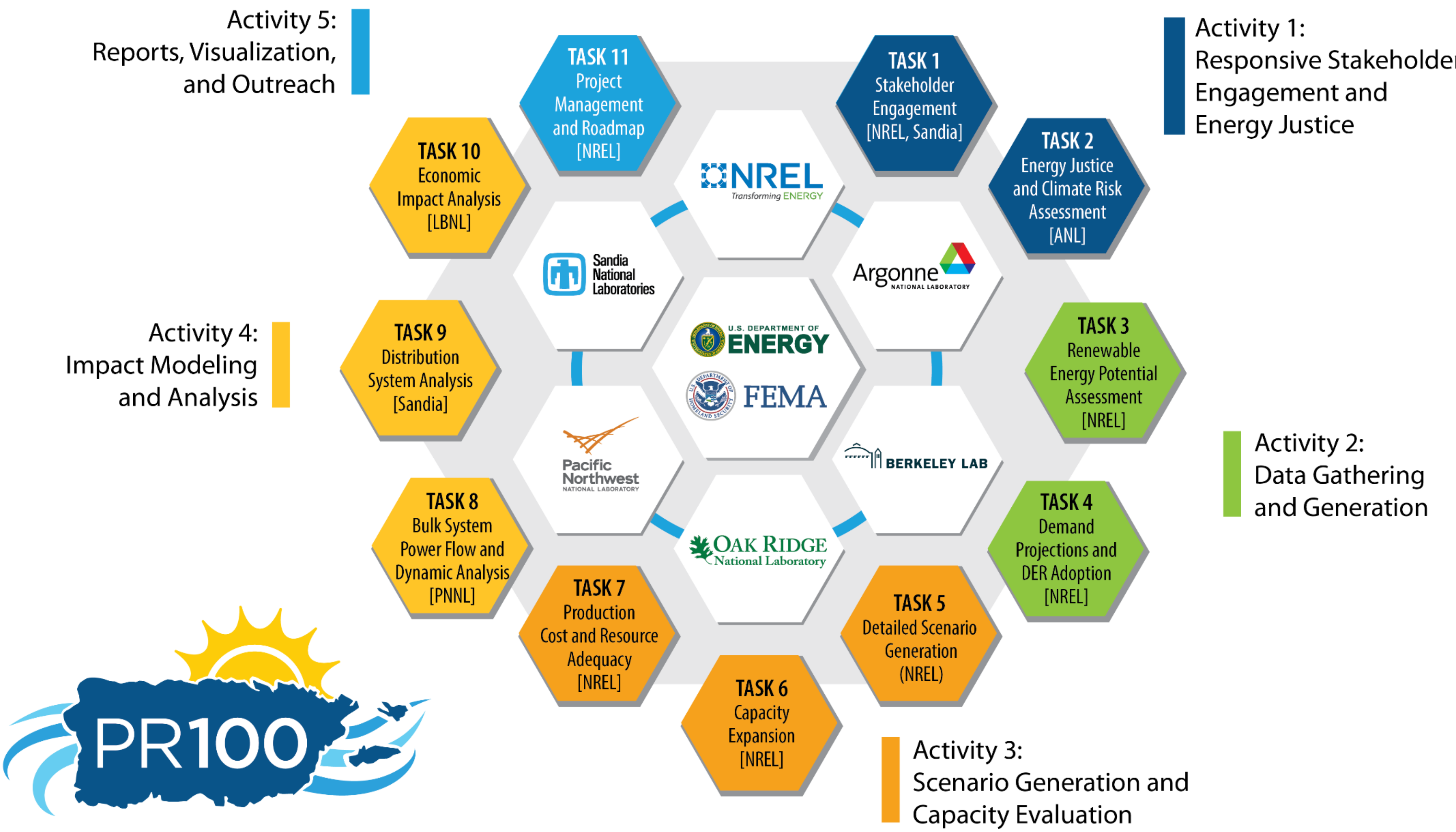

Figure 2. PR100 tasks led by six contributing national laboratories

The lead laboratory for each task is listed in brackets.

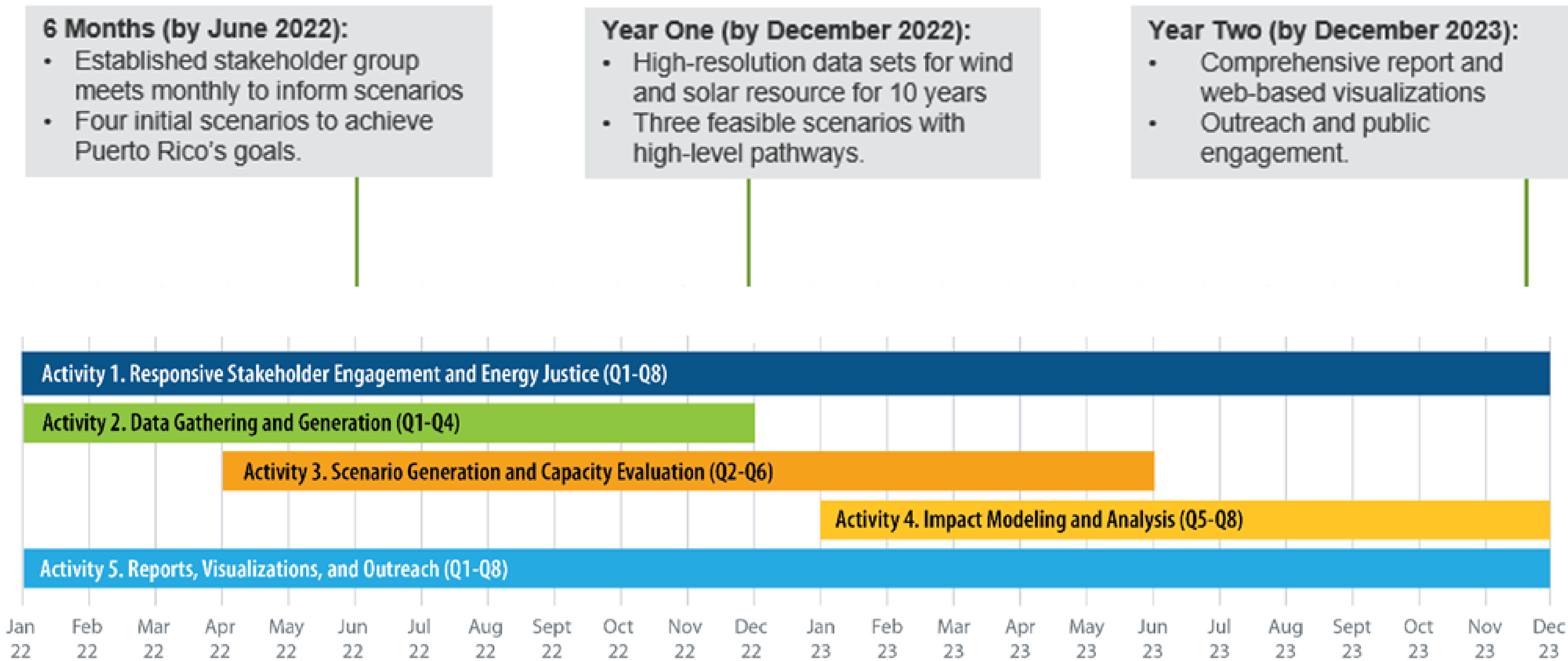

Figure 3. PR100 timeline

Table 1. Year 2 Scope Updates

PR100 Task	Scope Change
Stakeholder Engagement	• Provided additional support for PR100 community engagement events and roundtable conversations
Energy Justice and Climate Risk Assessment	• Facilitated inter-task coordination of energy justice considerations to be explicit about how energy justice principles were incorporated throughout the study
Resource Assessment	• Considered feasibility of analysis of alternative sites (e.g., agrivoltaics, parking lots, brownfields, and floating PV), and smaller ground-mounted configurations such as community solar • Included flood plains and sea level rise projections in land exclusions
Load and DER (Distributed Energy Resource) Adoption Projections	• Updated assumptions for DER adoption analysis (e.g., the Inflation Reduction Act of 2022) and increased the number of agents to better differentiate LMI, remote, commercial, and industrial buyers • Updated assumptions for demand projections; included medium-duty and heavy-duty EVs
Scenario Generation	• Considered how to revise scenarios in response to stakeholder feedback
Capacity Expansion Modeling	• Incorporated additional technologies and updated cost data
Resource Adequacy and Production Cost Modeling	• Incorporated changes that flowed from capacity expansion modeling
Distribution System Analysis	• Supported additional iterations in resilience evaluation of capacity expansion • Prepared distribution system model for additional DER scenarios
Economic Impact Analysis	• Evaluated approaches to address concerns with preliminary retail rate analysis results from Year 1

1.2 Assumptions

In this section, we discuss assumptions that pertain to the study as a whole. Assumptions that underpin specific analyses are discussed in relevant sections later in this report. Assumptions that pertain to the entire PR100 include the following:

- All modeling and analysis in PR100 assumes compliance with Puerto Rico energy policy, including Act 17; definitions of renewable energy assumed are in the:
    - Public Policy on Energy Diversification by Means of Sustainable and Alternative Renewable Energy in Puerto Rico Act (Act 82 of 2010, as amended) (Puerto Rico Legislative Assembly 2010)
    - Puerto Rico Climate Change Mitigation, Adaptation, and Resilience Act (Act 33 of 2019) (Puerto Rico Legislative Assembly 2019b, 33–2019)
    - Puerto Rico Electric Power Authority's (PREPA's) 2019 integrated resource plan (IRP) (Siemens Industry 2019; PREB 2020).

- We include in the modeling only generation technologies that meet the definition of renewable energy in the aforementioned public policy. Consistent with Act 82 as amended, technologies considered in PR100 include solar energy, wind energy, hydropower, marine and hydrokinetic renewable energy, ocean thermal energy, and combustion of biofuel derived solely from renewable biomass. Of the other resources listed in Act 82, we do not include geothermal energy, renewable biomass combustion, or renewable biomass gas combustion.
- The retirement schedule for existing fossil fuel generation units follows the retirements established in the 2019 IRP (Siemens Industry 2019; PREB 2020). Note that PREPA has stated that (1) the planned retirements from the 2019 IRP are based on assumptions regarding renewable technology cost and electric load reductions and (2) the new renewable energy generation (with compliance with minimum technical requirements) is assumed. Therefore, retirements might change, as those assumptions are not maintained on a schedule.
- With a historic commitment of federal recovery funds and statutory renewable energy targets to meet, several activities in Puerto Rico were happening in parallel with PR100. Table 2 summarizes these activities and how they relate to the study. Table 2 also lists federal funding and implementation activities related to PR100. Some stakeholders have expressed an interest in greater community participation in determining how these funds will be used.

Table 2. Federal Funding and Implementation Activities Related to PR100

Activity	Description	Relation to PR100
Renewable Energy and Energy Storage Procurement Process	PREPA and the Puerto Rico Energy Bureau (PREB) are procuring 3,750 MW of renewable energy resources and 1,500 MW of energy storage resources—in six tranches over 3 years—toward implementation of the 2019 IRP (PREB 2020 page 268, Table 17) .	The project team took into account and used as a benchmark the capacity of renewable energy being procured as part of these tranches. Some PR100 stakeholders have expressed concern about plans to site projects on lands designated for agricultural use.
Federal Emergency Management Agency (FEMA) Hurricane Maria Public Assistance and Hazard Mitigation Investments	FEMA authorized over $9.5 billion for Hurricane Maria recovery activities for the electric grid in Puerto Rico. Descriptions of projects approved by FEMA to begin design and construction activities can be found on FEMA's Accelerated Awards Strategy (FAASt) website.[26]	Projects funded by FEMA to upgrade Puerto Rico's electric generation, transmission, and distribution system were included in modeling if they were relevant and available in time to be included in the analysis.
FEMA Puerto Rico Power System Stabilization Task Force	In October 2022, after Hurricane Fiona left 950,000 Puerto Ricans without power, FEMA formed the Puerto Rico Power System Stabilization Task Force to perform repairs needed to stabilize the grid, including providing temporary generation to reach adequate capacities and reserves.	Projects identified by the Puerto Rico Power System Stabilization Task Force to be procured and deployed by the U.S. Army Corps of Engineers were considered. We did not include these projects in the modeling based on their temporary status.

[26] "FEMA Accelerated Awards Strategy (FAASt) Projects Execution," Official Portal of the Government of Puerto Rico, https://recovery.pr.gov/en/road-to-recovery/pa-faast/map

Activity	Description	Relation to PR100
U.S. Army Corps of Engineers (USACE) Multiple Award Task Order Contract, or MATOC, for Puerto Rico Power System Stabilization	In July 2023, USACE announced a solicitation for contractors to provide temporary fossil fuel generation at locations across Puerto Rico among other efforts to support power system stabilization in coordination with PREPA, Genera PR, and LUMA.	This effort is too recent to have been included in the modeling but is provided here for context on additional federal funding for Puerto Rico.
Puerto Rico Department of Housing (PRDOH): HUD Community Development Block Grant Disaster Recovery (CDBG-DR) and Community Development Block Grant Mitigation (CDBG-MIT) Programs	PRDOH is administering two relevant programs funded by HUD CDBG-DR and CDBG-MIT: the Energy Grid Rehabilitation and Reconstruction (ER1) Cost Share Program ($500 million) and the Electrical Power Reliability and Resilience (ER2) Program ($1.3 billion).	The objective of the ER2 program is to enhance electrical power system reliability, resilience, and affordability through the funding of projects that qualify as "electrical power system enhancements and improvements." Most ER2 program funds are anticipated to be used for distributed generation and microgrid projects. The National Renewable Energy Laboratory (NREL) provided technical assistance to PRDOH to support program planning and design.
Green Energy Trust	Puerto Rico Governor Pierluisi announced the creation of a Green Energy Trust to manage $400 million in CDBG-MIT funding, including up to $30 million from PRDOH through HUD. Act 17 requires the Puerto Rico Department of Economic Development and Commerce to create a Green Energy Trust.	Among other goals, the objectives of the trust are to (1) financially support projects that provide access to "green energy" to residents of low- and moderate-income (LMI) communities and (2) promote energy efficiency. NREL provided technical assistance to support planning and design of a new financial institution to support Puerto Rico's renewable energy transition.
2024 IRP Planning	LUMA is developing the next IRP for Puerto Rico, which includes a stakeholder engagement process to elicit input on the plan.	LUMA and the PR100 project team coordinated so that PR100 results could inform the IRP development process as appropriate.
Puerto Rico Energy Resilience Fund (PR-ERF)	The FY23 federal spending bill included $1 billion to improve the resilience of Puerto Rico's electric system, including grants to be administered by DOE's Grid Deployment Office for LMI households and others to deploy distributed solar and storage. In February 2023, GDO launched the PR-ERF to support Puerto Rico's grid resilience efforts and achieve the goal for the Commonwealth to meet 100% of its electricity needs with renewable energy by 2050.	Preliminary results from PR100 informed program design, and national laboratories contributing to PR100 are also supporting PR-ERF program design and implementation.

1.3 Lessons Learned From Hurricane Fiona

In Year 2 of the study, we increased our focus on seeking to understand and incorporating into the study lessons learned from the experience of Hurricane Fiona in Puerto Rico, starting with increased coordination across PR100 tasks to evaluate impacts and lessons learned within the context of the study. We expanded our stakeholder engagement approach (Section 2) to include visiting communities across Puerto Rico as part of a PR100 Community Engagement Tour, with support from local partner Hispanic Federation. Due to the extreme flooding caused by Hurricane Fiona, we enhanced our renewable energy assessment (Section 4) by conducting data review and analysis on storm surge and flood-prone regions. We also revised exclusion areas and assumptions based on this enhanced assessment, including development of updated geospatial data and capacity factor outputs. We revised our analysis of load projections (Section 5.1) to align with scenario updates (Section 6.1). We also modified our energy efficiency analysis (Section 5.2), expanded our electric vehicle adoption analysis (Section 5.3), and modified our DER adoption analysis (Section 7) based on updated data. In capacity expansion modeling (Section 8) we updated model assumptions and refined analysis on:

- Tranche procurements requirements, schedules, and implications
- Capacity expansion and production cost modeling assessment of system reliability
- Economics of utility-scale renewable energy versus operating costs of the existing system
- Tranche procurements to meet the renewable portfolio standard requirements.

2 Stakeholder Engagement

Robin Burton[1], Emily Moog[2], Matt Lave[2], Thomaz Kobayashi-Carvalhaes[3], and Mike Campton[1]

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[2] Sandia National Laboratories
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Section Summary

The purpose of stakeholder engagement for PR100 was to ensure the study was guided by stakeholder perspectives and priorities and answered their questions (Section 2.1); facilitate peer learning and information exchange; work with universities to contribute to and coordinate with the study (Section 2.2); and evaluate the effectiveness of our engagement (Section 2.3). This section describes these activities and results. A selection of key findings from this section is below, followed by actions stakeholders could take to advance progress toward Puerto Rico's energy goals. We identified these actions based on the results of our analysis, observations about Puerto Rico's current energy system, and knowledge of industry best practices.

Key Findings

Stakeholder Engagement

- Partnering with a local organization to facilitate events and advise on our engagement strategy was immensely valuable, and doing so ultimately expanded and deepened our connection with stakeholders and strengthened the study overall. (Section 2.1.1)
- Advisory Group members valued PR100 as a neutral forum where stakeholders with a diverse set of perspectives can discuss Puerto Rico's energy future. (Section 2.1.2)
- Stakeholders across Puerto Rico have divergent experiences, priorities, and visions for the future energy system. Some are strong proponents of a highly distributed system while others favor a larger role for utility-scale renewables. (Section 2.1.2)
- Advisory Group members highlighted the need to identify a local champion for implementation of Puerto Rico's energy transition. (Section 2.1.2.1)
- A lesson learned from Hurricane Fiona is that although distributed solar and storage systems provided resilience benefits by mitigating impacts of long-duration power outages, system owner education on topics such as conserving energy during outages is needed to increase the likelihood systems will perform as expected. (Section 2.1.2.1)
- Rooftop solar and storage and preservation of agricultural land are high priorities in communities across Puerto Rico; common challenges include not having property title, structural concerns that make buildings not suitable for rooftop solar, frequent flooding, and energy-dependent water systems that do not work during outages. (Section 2.1.2.3)

University Collaboration

- Findings from research conducted by project partners at University of Puerto Rico at Mayagüez (UPRM) highlight the need to focus on duration to restore power to 100% of customers after outages and prioritize resilient, renewable energy access for the last 5% of customers who are most vulnerable to long-duration power outages. (Section 2.2.2)
- UPRM findings emphasize the need to address the gap between energy justice conceptual frameworks and model-friendly metrics. Social vulnerability index and social burden analyses offer working metrics for energy justice. (Section 2.2.2)

Considerations

- Divergent stakeholder visions for Puerto Rico's energy future will need to be reconciled in the process of charting a pathway to implementation. Competing interpretations of existing policy such as land use regulations will need to be addressed.
- Feedback from stakeholders about implementation considerations has and can continue to inform scoping responsive technical assistance to implementing agencies, program design for the Puerto Rico Energy Resilience Fund, and other future implementation activities.
- Stakeholders have emphasized the need to determine who will lead the implementation phase of Puerto Rico's energy transition. Identifying the appropriate organizations and individuals to initiate and facilitate the process of fostering democratic participation and equity is crucial. The leader or leaders will play a pivotal role in ensuring the energy transition aligns with the aspirations of Puerto Ricans and upholds the principles of fairness and inclusivity.
- An important way to work toward energy justice is by developing a process to ensure broad and meaningful stakeholder participation in the planning, decision-making, and implementation of the pathway to 100% renewable energy. Developing implementation structures and processes that foster ongoing engagement and participation of communities and industry sectors, and which consider their unique and common impacts, aspects, and priorities, could support a just and inclusive energy transition for Puerto Rico.

2.1 Stakeholder Engagement and Information Exchange

In this section, we describe the various ways the PR100 project team engaged with Puerto Rico energy system stakeholders during the study to understand their perspectives and priorities. This engagement served multiple purposes. For PR100, we received input and engaged in dialogue to answer specific questions and get input to inform the methods, inputs, and ultimately results of the study. The engagements we facilitated throughout the study became a forum to hear from stakeholders about their experiences and their visions for Puerto Rico's energy future, and to create a record of what we heard. The forums were also a place where stakeholders could engage with each other, learn more about Puerto Rico's energy system, and hear how the national laboratories conducted modeling and analysis for the study.

Here we describe our approach to stakeholder engagement, including convening groups for ongoing engagement and input, community and sector-specific events, one-off meetings with specific stakeholders or groups, public webinars, and online community-building (Section 2.1.1). We discuss what we heard from stakeholders in these forums, topics and themes that emerged, and our synthesis and key takeaways (Section 2.1.2). We conclude with lessons learned from our experience engaging with stakeholders for this study and the extent to which our stakeholder engagement process can be a model for community participation in the implementation of Puerto Rico's transition to 100% renewable energy (Section 2.1.3).

2.1.1 Engagement Methods

The aim of PR100 was to conduct modeling and analysis to answer stakeholder questions about trade-offs between possible pathways for Puerto Rico to achieve the goal of 100% renewable electricity by 2050, in terms of technology mix, cost, resilience, emissions, and energy justice. To that end, it was imperative to engage with stakeholders for the duration of the study. Engagement began with presenting our study proposal to select stakeholders during the scoping phase in fall 2021 and broadened with the launch of the study in early 2022. From the beginning of PR100, the U.S. Department of Energy (DOE) and the project team sought to ensure the study reflected priorities of a broad cross-section of stakeholders, including those who historically have been underrepresented in energy planning discussions.

Before the launch of the study, the project team began convening an advisory group to ensure technical assistance provided to Puerto Rico by DOE and the national laboratories, including PR100, would be based on and informed by the expertise, perspectives, and priorities of a breadth of stakeholders. We also began searching for a local partner to facilitate engagements and advise on our stakeholder engagement strategy. Our approach was reflective of best practices and lessons learned in NREL's work with communities described by Ross and Day (2022), and of an earlier DOE resource on community energy planning by Jenkins et al. (2013).

2.1.1.1 Local Facilitator

In May 2023, NREL partnered with the Hispanic Federation in Puerto Rico[27] as a subcontractor to advise on stakeholder engagement and contribute to planning and facilitation of stakeholder meetings and community events. The Hispanic Federation in Puerto Rico is a nonprofit organization working on the reconstruction of Puerto Rico with a focus in ten key areas

[27] hispanicfederationpuertorico.org

including agriculture, renewable energy, environment, housing, community, and workforce development. As an organization they are dedicated to raising the voices of historically marginalized communities and shared their knowledge and connections with municipal and community leaders, community-based and environmental organization, government entities, and other key stakeholders across Puerto Rico in support of PR100. We invited additional members to the group, primarily representing community-based and environmental organizations, based on suggestions from the Hispanic Federation and our assessment of underrepresented sectors.

We received positive feedback and the Hispanic Federation received a warm welcome when we introduced them as our partner and meeting facilitator. From their deep connections with community organizations across Puerto Rico to expertise in both the energy and agricultural sectors, our work with the Advisory Group and communities was strengthened immensely by our partnership with the Hispanic Federation, and we are deeply grateful for their contributions.

> **Key Finding:** Partnering with a local organization to facilitate events and advise on our engagement strategy was immensely valuable, and doing so ultimately expanded and deepened our connection with stakeholders and strengthened the study overall.

2.1.1.2 Advisory Group

Project team members from DOE and the six participating national laboratories compiled a list of more than 100 prospective advisory group member organizations based on awareness of the stakeholder landscape formed during ongoing work in Puerto Rico. We aimed to develop (1) a comprehensive list of Puerto Rico energy system stakeholders with expertise relevant to topics within PR100 and (2) in the interest of energy justice, broad representation across sectors and society. Members of a steering committee convened by DOE, described in Section 2.1.1.3 (page 16), were invited to designate up to three representatives to participate in the Advisory Group. The initial list of prospective members primarily included stakeholders based in Puerto Rico and some outside experts. The purpose of the group, the roles and expectations of members, and the process for identifying initial prospective advisory group members and evaluating inclusion of additional members was described in the Puerto Rico Energy Recovery and Resilience Advisory Group (Advisory Group) member charter and addendum.

The project team down-selected the prospective member list, aiming for 50–60 members not including representatives of PR100 Steering Committee member organizations. Selection considerations included ensuring distribution across sectors and areas of expertise so no one sector or focus area was disproportionately represented, and no more than three representatives per organization were included. Starting in December 2021, NREL invited more than 85 individuals representing 53 organizations and 10 sectors to participate in the Advisory Group. We continued to invite additional members at the suggestion of existing members, the Hispanic Federation, and self-nomination throughout most of the study. As of October 2023, the Advisory Group had 116 confirmed members representing 73 organizations, including universities and other research institutions; federal and Puerto Rico government entities; solar and storage industries; finance, legal, community-based, and environmental organizations; retail, manufacturing, and consultants; and other sectors (see the Acknowledgments section, page v, for a list of members and affiliations). The Metrics and Evaluation section (Section 2.3, page 31) provides details about the composition of the Advisory Group, participation in meetings, and how both changed over time.

2.1.1.2.1 Meetings

The project team engaged with the Advisory Group frequently for feedback on study inputs, methods, and results, and to facilitate exchange between members to support decision-making and implementation of Puerto Rico's energy transition. We met monthly for the first 6 months (February to July 2022), and monthly or bimonthly for the remainder of the study (October 2022 to December 2023). We also held optional meetings on specific study topics to provide information and ask questions of those with interest or relevant expertise. Our first few monthly meetings were held virtually, due in part to the COVID-19 pandemic. Virtual meetings were hosted on Zoom, based on member feedback on their preferred platform. We often used breakout rooms for small group discussions, especially in our first few months, and we facilitated feedback and brainstorming sessions using Google Jamboard, Google Docs, and Microsoft Forms. We held our first in-person/remote (i.e., hybrid) meeting in May 2022. Meetings were facilitated by NREL for the first 6 months and then the Hispanic Federation beginning in July 2022. We provided English-Spanish bidirectional interpretation service for both remote and hybrid meetings to help ensure members of the Advisory Group and project team could speak, listen, and be understood in the language of their choice.

We held meetings more frequently, and more in the hybrid format, than originally planned, based on feedback from Advisory Group members who said they valued the PR100 stakeholder engagement process, and in-person meetings in particular, as a neutral forum where stakeholders with divergent perspectives could come together to discuss Puerto Rico's energy future. Over the 2 years of the study, we held 25 meetings with the Advisory Group, 15 full group meetings (9 hybrid and 6 remote), and 10 optional meetings on specific study topics (all remote). See the Metrics and Evaluation section (Section 2.3, page 31) for analysis of participation in Advisory Group meetings over time.

> **Key Finding:** Advisory Group members valued PR100 as a neutral forum where stakeholders with a diverse set of perspectives could discuss Puerto Rico's energy future.

2.1.1.2.2 Feedback Forms

We periodically used Microsoft Forms to collect written feedback from Advisory Group members. A registration form completed by 83 group members included questions about the role of each member in the energy transition, what they hoped to gain by participating in the group, and input to shape how we would work together. During the first 6 months of the study, when we were actively working with the group to define scenario definitions, we used Microsoft Forms with mixed success to prioritize input during a meeting and as another channel to collect feedback after meetings for anyone with more to share or who chose not to speak during meetings. In fall 2022, we asked members to complete a 6-month evaluation form and provide input on considerations for implementing Puerto Rico's energy future. From then on, we asked members to complete an online evaluation form after each full Advisory Group meeting. Our analysis of those results is described in the Metrics and Evaluation section (Section 2.3, page 31).

2.1.1.2.3 Written Input

Some Advisory Group members elected to submit written input to the PR100 project team in the form of emails and memos, some of which included links or attachments to reports, articles, or other reference material. The project team provided written responses to many of these submissions, and it incorporated feedback into the study as warranted.

2.1.1.3 Steering Committee

At the beginning of the study, DOE convened a steering committee composed of federal recovery funders—for example, the Federal Emergency Management Agency (FEMA) and the U.S. Department of Housing and Urban Development (HUD)—and local government implementers (e.g., PREPA, LUMA, the Puerto Rico Energy Bureau [PREB], the Puerto Rico Department of Economic Development and Commerce's Energy Policy Program, the Puerto Rico Department of Housing, and the Central Office for Recovery, Reconstruction, and Resiliency) to help guide DOE's portfolio of technical assistance projects. The PR100 project team met with the full PR100 Steering Committee periodically (every 3 to 6 months), and we worked closely with member organizations to review study progress on an ongoing basis. This report provides considerations to DOE and Steering Committee members to inform potential funding and implementation decisions by these key agencies.

2.1.1.4 Community Engagement and Roundtable Events

In early 2023, DOE, participating national laboratories, representatives of federal and Puerto Rico government agencies, and the Hispanic Federation of Puerto Rico traveled to communities across Puerto Rico on a PR100 Community Engagement Tour (Figure 4). The tour, held during the weeks of January 30–February 3, 2023, and March 27–31, 2023, included community engagement events, community visits, and roundtables with relevant sectors across Puerto Rico. U.S. Secretary of Energy Granholm participated in both weeks of the tour, following the announcement in October 2022 of the formation of the Puerto Rico Grid Modernization and Recovery Team. DOE readouts describe these events and the secretary's participation.[28]

The tour was conducted in part as a response to suggestions by members of the Advisory Group that we take PR100 "on the road" to raise public awareness for the study and the work DOE, federal partners, and Puerto Rico government partners were doing to support the energy transition in Puerto Rico, as defined in a memorandum of understanding (DOE 2022b) that enhances collaboration among federal agencies and the Commonwealth. Events were also aimed at raising awareness and requesting input to inform design of the $1 billion Puerto Rico Energy Resilience Fund,[29] launched by DOE in February 2023 to support Puerto Rico's grid resilience efforts and renewable energy goal, which has since been developed in consultation with local entities and communities to increase energy resilience and reduce the energy burden of vulnerable residents.

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[28] "Readout of Secretary Granholm's First Trip to Puerto Rico to Focus on Solution-based Energy Action Plans," October 26, 2022, DOE, https://www.energy.gov/articles/readout-secretary-granholms-first-trip-puerto-rico-focus-solution-based-energy-action.
"Readout of Secretary Granholm's Third Visit to Puerto Rico," February 3, 2023, DOE, https://www.energy.gov/articles/readout-secretary-granholms-third-visit-puerto-rico
" Readout of Secretary Granholm's March Visit to Puerto Rico," March 31, 2023, DOE, https://www.energy.gov/articles/readout-secretary-granholms-march-visit-puerto-rico.
[29] "Puerto Rico Energy Resilience Fund," DOE, https://www.energy.gov/gdo/puerto-rico-energy-resilience-fund.

Figure 4. Photos from community events in January and February 2023 in the east (above) and in March 2023 in the west (below) of Puerto Rico during the PR100 Community Engagement Tour

Photos by Conor McCabe, DOE (above) and Anthony Martinez, DOE (below)

In a series of small, in-depth roundtable discussions between Secretary Granholm, the PR100 project team, and representatives of key industry sectors, we sought to understand their priorities and challenges and to receive input to inform PR100, the Puerto Rico Energy Resilience Fund, and implementation of Puerto Rico's energy transition to 100% renewable energy (Figure 5). Sectors with whom we held roundtables during the tour were:

- Business community (commercial and industrial)
- Agriculture sector
- Workforce development and labor needs
- People with disabilities and medical needs.

We held virtual roundtables with four additional sectors:

- Solar and storage developers
- Philanthropic organizations
- Energy-focused nonprofit organizations
- Community-based organizations (not energy-focused).

Figure 5. Representatives of the agricultural sector (above left), organizations that represent people with disabilities (above right), and the business sector (below) participated in roundtables with DOE, the PR100 project team, and the Hispanic Federation in March 2023.

Photos by Anthony Martinez, DOE

2.1.1.5 Public Webinars

Webinars providing progress updates, preliminary findings, and final results to broader audiences were one of the project team's primary means of engaging with the public. These events were interactive to create another opportunity to understand stakeholder priorities for Puerto Rico's energy future. We used Poll Everywhere[30] to ask audience members questions during webinars and show anonymous responses in real time. Webinar presentations and recordings are available online in English and Spanish,[31] as is a video of stakeholder insights on PR100,[32] recorded as part of our kick-off event.

2.1.1.6 Online Community

In May 2022, we launched the Puerto Rico Energy Recovery and Resilience online community[33] on the Mobilize platform. The main community group is open to the public, and a private subgroup is available to Advisory Group and PR100 project team members. The platform provides another channel for sharing information and resources relevant to Puerto Rico's energy transition, updates about the study and other technical assistance engagements, and for fostering peer exchange and connections. All members can post, comment, and share resources. As of October 2023, there were more than 400 members in the main group and more than 100 members in the Advisory Group subgroup, including project team members. Figure 6 shows that member activity across all groups in the community (posts, comments, and resource downloads) spiked after each public webinar.

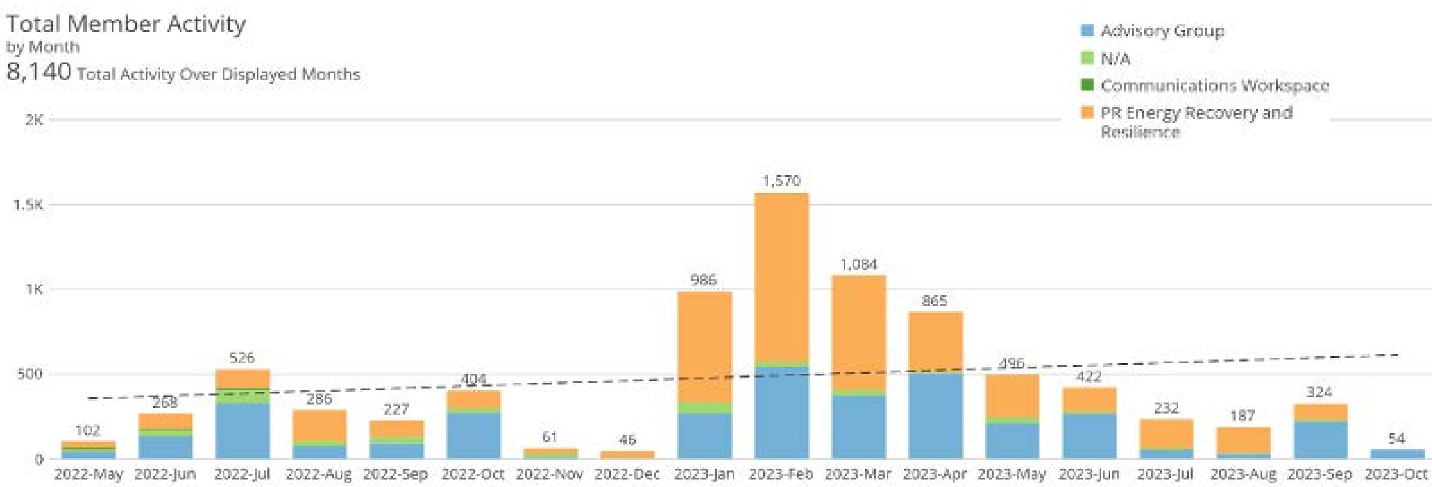

Figure 6. Total member activity by month in the online community

Graphic from Mobilize

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30 https://www.polleverywhere.com/

31 Recordings are in the Puerto Rico Energy Recovery and Resilience playlist in the NREL Learning channel on YouTube: https://www.youtube.com/playlist?list=PLmIn8Hncs7bG69YhHJFiHsG4A0qHX0gSn.

32 "Stakeholder Insights on PR100: A Resilient Clean Energy Future for Puerto Rico," NREL Learning channel on YouTube, https://youtu.be/nICFlzKUNTg.

33 "PR Energy Recovery and Resilience," https://pr-energy.mobilize.io/main/groups/49360/lounge.

2.1.2 What We Heard: Engagement Results

Throughout engagement with our large Advisory Group, our Steering Committee, community and industry sectors, and members of the public, we received, processed, and incorporated an enormous amount of feedback. In this section, we summarize much of what we heard from stakeholders, and how we incorporated it into the study when warranted. As mentioned, in addition to eliciting study input, our engagements provided a forum to hear from stakeholders about their experiences and visions for Puerto Rico's energy system broadly, beyond information that we could necessarily use as study input, and to document what we heard as a source of information for future efforts, which we also do in this section.

2.1.2.1 Advisory Group and Steering Committee

2.1.2.1.1 Study Input

The project team met with the Advisory Group regularly for input and discussion on PR100 methods, inputs, and results and to understand members' perspectives and priorities more generally. A focus during the first 6 months of the study was to iterate on definitions of possible pathways toward 100% renewable energy, or scenarios, to ensure our modeling and analysis would help answer stakeholders' questions about where to develop renewable energy projects; the mix of renewable energy technologies, including utility-scale and distributed (e.g., rooftop) generation and storage; resilience; and so on. We sought input on topics such as land use and energy justice priorities, meaningful scales at which to aggregate and report results, and technology costs. Later in Year 1 of the study, we sought input on topics including lessons learned from Hurricane Fiona in September 2022, considerations for implementing Puerto Rico's energy transition, and preliminary results presented in our Year 1 progress update (Blair et al. 2023).

In Year 2 of the study, we asked Advisory Group members for input on Year 1 preliminary results, updates to study scope and scenarios based on Year 1 feedback (see Section 6.1.4, page 180 for a summary of updates), and integration of energy justice principles throughout the study. Through the course of engagement, Advisory Group members raised priority topics, which we discussed and sought to reflect in the study.

The input we received, presented in a series of tables in Appendix B and integrated throughout this report, was critical for the design of our initial modeling scenarios (described in Section 6, page 173), and refinement of the study across modeling efforts to better align with stakeholder questions and priorities.

> **Key Finding:** Stakeholders across Puerto Rico have divergent experiences, priorities, and visions for the future energy system. Some are strong proponents of a highly distributed system while others favor a larger role for utility-scale renewables.

2.1.2.1.2 Lessons Learned From Hurricane Fiona

On September 18, 2022, Hurricane Fiona, a Category 1 hurricane, made landfall along the southwest coast of the main island of Puerto Rico. It resulted in heavy rainfall, catastrophic flooding, landslides, power outages to all 1.5 million customers, and water service interruptions for 760,000 customers across Puerto Rico for 2 weeks or longer (Pasch, Reinhart, and Alaka

2023).[34] LUMA reported power was restored to 99% of customers by October 10 (LUMA 2022b).

We postponed an Advisory Group meeting scheduled for late September 2022 since so many in Puerto Rico were still without power and focused on recovering from the impact of Hurricane Fiona. At that time, a member of the group urged us to hold a special Advisory Group meeting to solicit input from members about their experiences during the crisis, their firsthand evaluations, and recommendations to support analysis of the inability of the electric system to withstand impacts. Inspired by this suggestion, we held a group discussion focused on lessons learned from Hurricane Fiona, and how they could be incorporated into PR100, during a hybrid meeting of the Advisory Group in October 2022 attended by U.S. Secretary of Energy Jennifer Granholm. Specifically, participants were asked to focus on how the lessons could be used to inform PR100. Some major topics of that discussion were that:

- Experience with renewable energy was generally positive. A solar developer surveyed its residential clients after Hurricane Fiona and found 85% were satisfied with their system performance during and after Fiona. Most of those who were unhappy had some issues with batteries. In this and other discussions, it was mentioned that some customers were unfamiliar with PV-plus-battery system operation during outage events and so continued their electric consumption as normal. Because of 3 days of dark skies associated with Hurricane Fiona, many batteries were fully depleted.
- Resilience can have many levels and is location-specific. What is considered resilient in one region may not be resilient in another region. As one example, in mountainous, remote areas, even though people had generators, landslides made accessing diesel fuel very difficult. As another example, an urban region generally was able to provide services (e.g., stores, restaurants, and other facilities had generators), but older persons in a tall apartment building were unable to leave to obtain these services because the elevator in the building was nonfunctioning due to the power outage. PR100 focused on location-specific analysis to understand the areas most affected by disruptions (e.g., earthquakes and hurricanes) and the solutions that would provide the resilience needed for those communities.
- A key result of Hurricane Fiona was formation of the Puerto Rico Power System Stabilization Task Force in October 2022, [35] made up of FEMA, DOE, the U.S. Army Corps of Engineers (USACE), and the U.S. Environmental Protection Agency (EPA), and approval of FEMA funds to provide emergency generation to stabilize the electric system with 350 MW of emergency generation.[36] USACE's five-year, $5 million Multiple Award Task Order Contract (MATOC) for Puerto Rico Power System Stabilization,[37] which will install, and operate temporary fossil fuel power generation of 350–700 MW at various locations throughout Puerto Rico, is a continuation of this emergency response.

[34] "More than 100,000 Clients in Puerto Rico Are Still Without Power 2 Weeks After Fiona," Becky Sullivan, National Public Radio, October 2, 2022, https://www.npr.org/2022/10/02/1126462352/puerto-rico-hurricane-fiona-luma-energy-power-outages.
[35] "Puerto Rico Power Upgrade Project," U.S. Army Corps of Engineers, https://www.usace.army.mil/Business-With-Us/Contracting/Contracting-in-Puerto-Rico/
[36] "Puerto Rico gov't, FEMA announce arrival of 3 mega generators," https://newsismybusiness.com/puerto-rico-govt-fema-announce-arrival-of-3-mega-generators/
[37] "Multiple Award Task Order Contract (MATOC) for Puerto Rico Power System Stabilization, Power Generation Services," U.S. Army Corps of Engineers, https://sam.gov/opp/8aa51a688b314a9db86b243d81be8bf8/view#general

Key Finding: Advisory Group members' reflections on impacts and solutions identified during Hurricane Fiona can inform implementation decisions. Stakeholders shared that although distributed solar and storage systems provided resilience benefits by mitigating impacts of long-duration power outages, system owner education on topics such as conserving energy during outages is needed to increase the likelihood systems will perform as expected.

2.1.2.1.3 Implementation Considerations

We asked members to complete an online feedback form regarding implementation considerations, including to rank 10 considerations regarding implementation of PR100 results and to explain their selections. We received 29 responses from September through December 2022. The top three considerations in order of priority were funding, political will, and timing as shown in Figure 7.

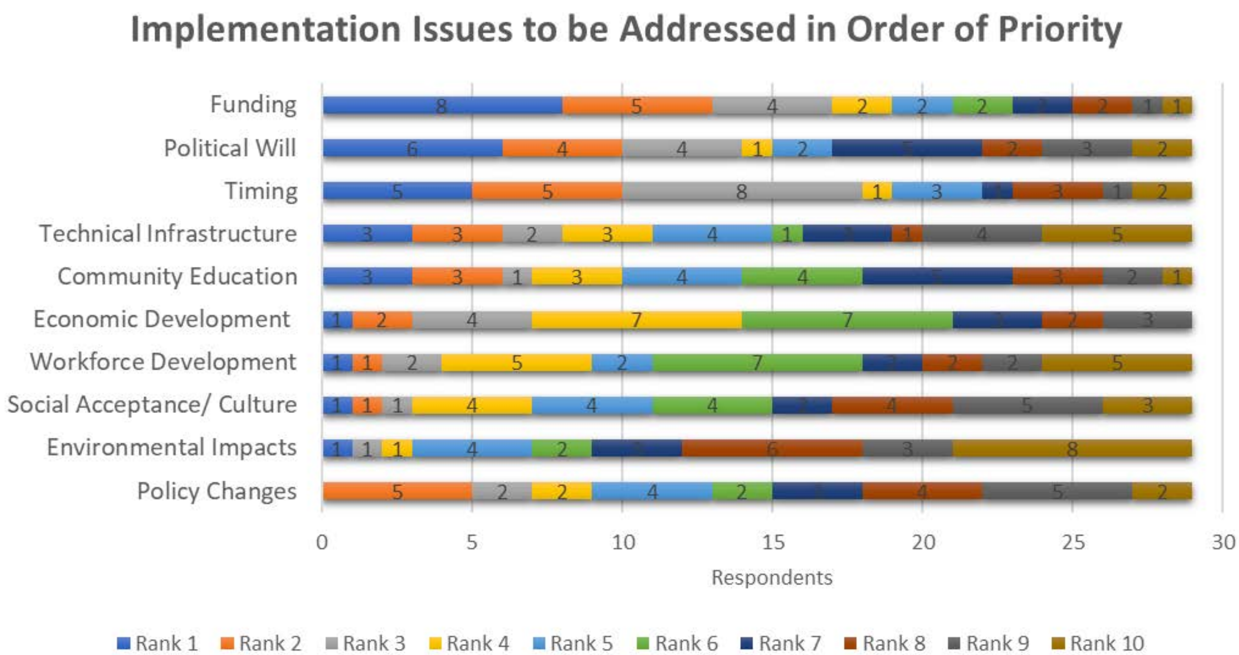

Figure 7. Advisory Group respondents' ranking of top considerations for energy transition implementation

While PR100 provides useful data and analysis, it will be up to decision makers and advocates to decide which actions to take to ensure Puerto Rico reaches its 100% renewable energy goal by 2050. In Year 1 of the study, we asked Advisory Group members for their perspectives on important considerations regarding implementation of Puerto Rico's energy transition. This feedback helped inform the Implementation Roadmap developed as part of the study (Section 17, page 590).

Key Finding: Advisory Group members identified funding, political will, and timing as important considerations for the implementation of Puerto Rico's energy transition informed by PR100.

Comments on the topics provided valuable insight into what stakeholders see as potential barriers or factors to consider regarding implementation of the energy transition. Gaining this understanding can inform discussions about implementation and decision-making.

For *funding*, respondents wanted to understand who is funding Puerto Rico's energy transition, what are the timelines and benefits associated with various funding options, how decisions are made regarding the use of available FEMA and HUD recovery funding from Hurricane Maria, how to access project finance at reasonable rates in Puerto Rico's fiscal environment, and how to take advantage of other federal funding opportunities such as the Infrastructure Investment and Jobs Act, the Inflation Reduction Act of 2022. Suggestions included directing FEMA and HUD funding to capital investments in rooftop solar and storage, and to use other sources of funding for grid-hardening and utility-scale renewable energy alternatives. Suggestions also included classifying energy projects based on complexity and benefits, and prioritizing funding for the most-beneficial, least-complex projects. Additional comments included a call to prioritize and promote social equity at the legislative level, an observation that if there is political will funding will be available, and the need to identify who is making decisions and who the study is really advising.

On the topic of *political will*, respondents identified the need for political will to (1) put vulnerable communities ahead of financial interests of those closest to governing leaders, (2) maintain long-term and stable energy policies, and (3) allow for innovation. One respondent's perception of the current political will of the Puerto Rico government is development of fossil infrastructure, particularly liquefied natural gas, noting the government has no incentive currently to boost renewable energy, which is where reconstruction money must be used. Another respondent noted implementation of the energy transition depends on the political will of the federal and Puerto Rico government to support PR100 and Advisory Group member participation. Other respondents suggested making the government follow considerations presented in the PR100 final report (i.e., this report) and making all gubernatorial candidates endorse and sign agreement with PR100 results and Advisory Group member recommendations. One respondent noted that the study is only likely to effect change through education because while community activism is sometimes useful, the community has no leverage on the funds.

Comments regarding *timing* centered on the need for urgent action. Respondents noted the importance of presenting considerations from PR100 in a timely way to ensure the PR100 effort was not only an academic exercise—before (1) study results and stakeholder input that informed it are no longer useful, (2) financial commitments are made by the Puerto Rico government and companies pushing an agenda of more fossil infrastructure, and (3) the Financial Oversight and Management Board for Puerto Rico might nullify the study findings. Suggestions included to (1) understand the history of slow decision-making and progress due to federal and Puerto Rico government procedural requirements and reviews when establishing a timeline for implementation, (2) consider the timing and phases of execution in PR100 results to support decision-making by PREB in particular, and (3) identify the critical path to detail necessary next steps for timely progress. Calls for near-term action (in the next 3–5 years) include FEMA investments in the grid to support rapid deployment of a high penetration of renewables; to protect the most vulnerable families and save lives by deploying rooftop solar and storage in a participatory way; and to support Puerto Rico's economy by not exporting billions of dollars for fuel from outside of Puerto Rico. Another respondent noted the need to communicate the implementation timeline to the public and that 30 years is a short time for an energy transition that maintains system reliability and price stability.

In addition to information received in the feedback form, some Advisory Group members highlighted the need to identify a champion to lead the decision-making process and implementation of Puerto Rico's energy future consistent with practices that support a just energy transition.

Key Finding: Advisory Group members highlighted the need to identify a local champion for equitable implementation of Puerto Rico's energy transition.

One Advisory Group member emphasized the need to clearly state decisionmakers' obligations and responsibilities to ensure energy justice and achieve a sustainable transition to 100% renewable energy for Puerto Rico. Some examples of these obligations and responsibilities suggested by this Advisory Group member are:

- "To ensure distribution, procedural, recognition, restorative, and transformative justice."
- "To ensure energy democracy."
- "To distribute the costs (e.g., pollution) and benefits (e.g., economic opportunities) fairly and equitably among people."
- "To recognize and accommodate distinctive needs of most vulnerable groups.
- "To remedy and not repeat past harms."
- "To make decisions about the energy system through a participatory process that considers the voices and concerns of affected communities."
- "To be transparent with and to communicate effectively with the people."
- "To use the best available data to integrate energy justice in decision-making (e.g., social vulnerability modeling, social burden analysis, and cost of environmental impacts)."
- "To prioritize the well-being of all Puerto Rico's residents and communities."
- "To ensure sustainable land use planning."
- "To prioritize investments in resilient and sustainable infrastructure."[38]

2.1.2.2 Industry Sectors

In roundtables with industry sectors in spring 2023, participants responded to the following general questions, which were modified for each group. Responses are summarized in Appendix B (Table B-3, page 669).

- What are the unique energy needs of your sector?
- What are the ways you have been impacted by the current energy system?
- What would you like to see in the future energy system?

[38] Personal correspondence: email from Maritere Padilla Rodríguez to PR100 project team on November 30, 2023

- What do you see is the role of your sector in the transition to renewable energy?

Key Finding: Engaging representatives of multiple industry sectors about how they are impacted by the energy system and what they would like to see in the future highlighted unique perspectives and commonalities. Impacts of power system disruptions across sectors include higher costs, damaged equipment, harm to reputation and competitiveness, and mental and physical health effects. All sectors need reliable, resilient, affordable energy to achieve their objectives.

- The *commercial sector* needs reliable, high-quality power to be productive and competitive.
- *People with disabilities* need to be able to power energy-dependent medical equipment and refrigerate medication.
- The *agriculture sector* prioritizes the protection of farmland for production.
- Those in *workforce development* seek to address labor needs by understanding project lifecycles and coordinating across educational resources.
- *Philanthropists* need information and tools to inform their investments.

2.1.2.3 Community Events

During the PR100 Community Engagement Tour of communities across Puerto Rico in January, February, and March 2023 (described in Section 2.1.1.4, page 16) we received comments in response to the following general questions, variations of which we asked in each community:

- What are the unique aspects of this community that are important for those doing energy planning to consider?
- What are the most pressing energy challenges facing this community? How are people impacted by the electric infrastructure that exists?
- Who are the most vulnerable people or populations in this community?
- Which energy solutions would you like to see in the future?
- What would you not want to see?
- What is the ideal way of sharing information and engaging with this community in the planning process?

Feedback from participants increased the PR100 project team's understanding of unique characteristics and similarities of communities across Puerto Rico and past harms associated with the energy system. It also enabled the team to gather more information about what people would and would not like to see in the future. Feedback also informed program design of DOE's Puerto Rico Energy Resilience Fund. A selection of comments by community members are listed in Appendix B (Table B-4, page 671).

Key Finding: People in communities across Puerto Rico have experienced extreme hardship and loss of life due to frequent and long-duration power outages. While some people and groups are particularly vulnerable—including the elderly, people with disabilities and chronic health conditions, and low-income households—everyone, including students, families with children, and the middle class, needs access to reliable energy and clean water. Rooftop solar and storage and the preservation of agricultural land are high priorities in all communities. While each community has unique aspects, common challenges include not having property title; not having existing electrical service; structural concerns such as the roof or electrical system being unsuitable for rooftop solar installation; frequent flooding; and energy-dependent water systems that do not work during outages.

2.1.3 Community Participation in Implementation

In this section, we discuss the extent to which our stakeholder engagement process could be a model for community participation in the implementation of Puerto Rico's transition to 100% renewable energy.

On the Spectrum of Community Engagement to Ownership (Gonzalez 2019)[39] (Figure 8), based in part of Arnstein's ladder of citizen participation (Arnstein 1969), the study falls primarily in the "involve" stage, with elements of "consult" and "collaborate." We sought to actively involve a breadth of stakeholders from the beginning of the study to define the scenarios and inform model inputs to increase the likelihood that results would answer their questions about how to achieve Puerto Rico's energy goals. As noted in Section 2.2 (page 28), we formed and began actively working with the Advisory Group at the launch of the study in February 2022. We began scoping the study in the second half of 2021 and presented the approach to select groups of stakeholders in that phase. For future studies interested in participatory research and community ownership of study design and results, researchers might want to consider engaging communities sooner in the study design process in order to move along the spectrum to "defer to" communities.

[39] The six stages of the spectrum are Ignore, Inform, Consult, Involve, Collaborate, and Defer to.

STANCE TOWARDS COMMUNITY	0 IGNORE	1 INFORM	2 CONSULT	3 INVOLVE	4 COLLABORATE	5 DEFER TO
IMPACT	**Marginalization**	**Placation**	**Tokenization**	**Voice**	**Delegated Power**	**Community Ownership**
COMMUNITY ENGAGEMENT GOALS	Deny access to decision-making processes	Provide the community with relevant information	Gather input from the community	Ensure community needs and assets are integrated into process & inform planning	Ensure community capacity to play a leadership role in implementation of decisions	Foster democratic participation and equity through community-driven decision-making; Bridge divide between community & governance
MESSAGE TO COMMUNITY	***Your voice, needs & interests do not matter***	***We will keep you informed***	***We care what you think***	***You are making us think, (and therefore act) differently about the issue***	***Your leadership and expertise are critical to how we address the issue***	***It's time to unlock collective power and capacity for transformative solutions***
ACTIVITIES	Closed door meeting Misinformation Systematic	Fact sheets Open Houses Presentations Billboards Videos	Public Comment Focus Groups Community Forums Surveys	Community organizing & advocacy House meetings Interactive workshops Polling Community forums	MOU's with Community-based organizations Community organizing Citizen advisory committees Open Planning Forums with Citizen Polling	Community-driven planning Consensus building Participatory action research Participatory budgeting Cooperatives
RESOURCE ALLOCATION RATIOS	**100%** Systems Admin	**70-90%** Systems Admin **10-30%** Promotions and Publicity	**60-80%** Systems Admin **20-40%** Consultation Activities	**50-60%** Systems Admin **40-50%** Community Involvement	**20-50%** Systems Admin **50-70%** Community Partners	**80-100%** Community partners and community-driven processes ideally generate new value and resources that can be invested in solutions

Figure 8. Spectrum of community engagement to ownership

Gonzalez (2019)

Similarly, as stakeholders continue to implement Puerto Rico's transition to 100% renewable energy, it is evident that achieving energy justice for the people of Puerto Rico is a top priority for many. This feedback, which we heard repeatedly from various stakeholders, underscores the importance of involving stakeholders even earlier in the process. As an example, one member of the Advisory Group suggested the creation of an advisory body or committee that would include the views of experts, the public, farmers, academia, businesses to inform siting decisions, such as the Maryland Soil Health Advisory Committee, staffed by the Maryland Department of Agriculture (MDA), which includes representatives from across the agricultural and environmental sectors.

Two important considerations from our Year 1 report (Blair et al. 2023) hold:

- Stakeholders have emphasized the need to determine who will lead the implementation phase of Puerto Rico's energy transition. Identifying the appropriate organizations and individuals to initiate and facilitate the process of fostering democratic participation and equity is crucial. The leader or leaders will play a pivotal role in ensuring the energy transition aligns with the aspirations of Puerto Ricans and upholds the principles of fairness and inclusivity.
- An important way to work toward energy justice is by developing a process to ensure broad and meaningful stakeholder participation in the planning, decision-making, and implementation of the pathway to 100% renewable energy. Developing implementation structures and processes that foster ongoing engagement and participation of communities and industry sectors, and which consider their unique and common impacts, aspects, and priorities, could support a just and inclusive energy transition for Puerto Rico.

2.2 PR100-UPRM Partnership

To support the PR100 project, Sandia National Laboratories executed a contract with electric grid researchers in the Electrical and Computer Engineering Department at UPRM and facilitated oversight of the UPRM work. UPRM professors Marcel Castro-Sitiriche, Agustin Irizarry-Rivera, Lionel Orama Exclusa, and Eduardo Lugo, and a team of graduate student researchers executed the work. This partnership was intended both to allow laboratory researchers to take on suggestions from Puerto Rican researchers on appropriate modeling for the Puerto Rico context and to support Puerto Rican researchers performing work interconnected with the PR100 project. The contributing professors are well established in their fields and have researched and published extensively on renewable energy in Puerto Rico, as well as being focused on representing community interests and saving lives by increasing the resilience of Puerto Rico's energy system.

The UPRM team met with national laboratory team members from multiple PR100 tasks on a roughly fortnightly basis. Discussions regularly included UPRM team members' advice on the laboratories' modeling decisions and scenario development, as well as current research by the UPRM team and how it could inform PR100. The UPRM team regularly participated in the Advisory Group meetings, and it presented at several of them, including on energy justice for disaster restoration.

The work with the UPRM team encompassed three areas: UPRM team advice on PR100 modeling (Section 2.2.1), UPRM-led development of energy justice metrics for Puerto Rico

(Section 2.2.2), and a UPRM-led questionnaire on the relationship between energy supply and mental health (Section 2.2.3).

2.2.1 Area 1: Advice on PR100 Modeling

In Area 1, the UPRM team advised the laboratories' modeling team on several topics. The team shared its insights on approximate prices for residential PV and battery installations, and for appropriate residential system sizing for different income groups. The UPRM team advised on which electrical uses constituted critical residential load and the magnitudes of those loads. The team investigated the rate of installation of residential systems in Puerto Rico, including suspected installations that are not subscribed to net metering along with reasons a household might not subscribe to net metering. And, the team produced geographically granular restoration trends for different parts of Puerto Rico after Hurricane Maria and Hurricane Fiona.

A memo was produced in support of the work under Area 1. It is anticipated to be published by the UPRM team as a public report by the conclusion of the PR100 project.

This memo, "Distributed Rooftop Solar Photovoltaic Generation Adoption in Puerto Rico" (Irizarry-Rivera et al. 2023), is a discussion of current PV and battery adoption rates in Puerto Rico that incorporates households that do not interconnect. Its main findings include:[40]

> "The number of net metering clients is doubling every 15 months," and the "installed capacity of net metering solar PV systems is doubling 18 to 19 months."
>
> "The newly installed distributed solar photovoltaic generation capacity with net metering is about 20 MW/month and net metering clients are increasing by 1% of total residential clients every 5 months."
>
> "In 14 months the installed distributed electric storage doubled, from 401 MWh to 807 MWh. This trend is persistent, the installed generation capacity of net metering solar PV systems is doubling every 14 months."
>
> "In Puerto Rico utility-scale renewables are not growing while distributed renewables are growing at an accelerated pace."
>
> "We estimate that non-net metering distributed solar photovoltaic generation is around 33% of net metering installations."

2.2.2 Area 2: Energy Justice Metrics Within the Context of Puerto Rico

In Area 2, the work, led by UPRM, examined last-restored customers. Extant metrics focus on restoring power to many customers quickly and may not be sensitive to the last few percent of customers to be restored. As a result, these last-restored customers may experience disproportionately long-duration outages and hence may experience disproportionate consequences, including higher death rates. This concern is particularly critical for remote and rural areas in Puerto Rico, where access to alternative critical services may be limited due to difficulties with travel or money.

[40] Personal correspondence: email from Marcel Castro Sitiriche to PR100 project team on September 27, 2023

UPRM drafted two memos under Area 2:

- "Resilience, Energy Justice, and Rooftop Solar Photovoltaic Mitigation Alternatives" (M. J. Castro-Sitiriche et al. 2023) suggests energy justice metrics for the context of Puerto Rico. Key topics include:[41]
    - Total time of power service restoration to 100% of the clients affected by a major event is a recommended metric.
    - Special emphasis of the last 5% of the customers restored is needed to effectively identify mitigation strategies to overcome the vulnerability to long power outages.
    - The number of deaths resulting from a long power outage needs to be prominently included in resiliency metrics although its analysis requires a complex systems approach.
    - The focus on the resiliency of electric services, which includes the electric grid, needs to replace the explicit or implied emphasis on grid resiliency. People need resilient electric power service, and often the grid is not the best way to deliver it.
- A paper describing energy justice metrics and how they should best be applied to Puerto Rico is in progress.

2.2.3 Area 3: Questionnaire on Energy Supply and Mental Health

In Area 3, the questionnaire was administered in June 2023 and was advertised before then in social media and local newspapers. It focused on the mental health effects of unreliable electrical service, particularly during disasters but also as a day-to-day concern, and on the prevalence and funding mechanisms for achieving household energy resilience. The 789 respondents to the survey addressed questions related to PV adoption, blackout frequency and impact, and health impacts.

A memo summarizing questionnaire responses, "Comprehensive Survey of Residential Photovoltaic Systems in Puerto Rico," which describes survey results and trends," was produced (Lugo-Hernández et al. 2023). Main findings presented in this memo are that:[42]

> "92% of the participants with mental health diagnosis reported that their mental health symptoms worsen with electric blackouts. The majority of people reported experiencing feelings of anxiety, frustration, anger and desperation when experiencing blackouts."
>
> "When asked about what appliances or equipment are essential for them to power during a blackout they indicated that Refrigerators (99%), Fans (77%), Stoves (35%), and respiratory therapy equipment or respirators (30%)."
>
> "Customers report great dissatisfaction with various electric service indicators resulting in 79% being Unsatisfied or Very Unsatisfied with their electric bill. The majority of participants (66%) felt that the electric service has deteriorated since LUMA took over the administration of energy distribution. Also, 66% of those

[41] Personal correspondence: email from Marcel Castro Sitiriche to PR100 project team on September 27, 2023.
[42] Personal correspondence: email from Marcel Castro Sitiriche to PR100 project team on September 27, 2023

who have needed assistance from LUMA's customer service felt Unsatisfied or Very Unsatisfied."

"29% of participants reported having 3 or more weekly blackouts and 44% reported that it takes more than 4 hours on average to regain service."

"27% of the sample have a solar energy system of which 95% have batteries. The majority of study participants (66%) that do not have a solar system, indicate that cost is the main reason for not having one and 78% of those participants have no plan to purchase a solar system during the next year."

"Our sample consisted of people who mostly have private health insurance (85%); 15% have Government issued health insurance or have no insurance; 30% have some medical equipment that needs to be powered by electricity. The two most common needed equipment were respiratory therapy equipment or respirators, and refrigerators (for insulin or other medication)."

"Energy burden is an area that needs more research as study results show that 60% of participants pay more than $100 monthly in their electric bill and 26% pay on average more than $200."

2.3 Metrics and Evaluation

2.3.1 Motivation and Background on Stakeholder Engagement Evaluation

Effective stakeholder engagement enables the incorporation of a breadth of perspectives and priorities within a project and aids in wider dissemination of results. Evaluating the effectiveness of stakeholder engagement enables accountability and reduces the gap between the engagement's promises and the underlying evidence supporting its practice (Esmail, Moore, and Rein 2015). For PR100, engagement helped researchers and project members keep up with ongoing changes and realities that infrastructure managers, financiers, designers, and communities must face directly. Assessing engagement iteratively allows midcourse corrections and improvements from the research group and its activities (Albritton et al. 2014, 40). Comparative studies show that stakeholder engagement along with continuous engagement assessment leads to higher effectiveness, efficiency, equity, flexibility, legitimacy, sustainability, and replicability in research projects (Goodman and Sanders Thompson 2017; Sherman and Ford 2014). All these benefits helped support PR100's overarching goals of analyzing alternatives for Puerto Rico's resilience and renewable energy goals in terms of decision-making needs. Particularly, the objectives for PR100 stakeholder engagement aim to (1) inform development of scenarios to meet Puerto Rico's goal of 100% renewable energy by 2050 and (2) understand and answer stakeholder questions about possible pathways to 100% renewable energy.

The literature on stakeholder engagement is vast and growing, yet the literature specific to evaluation methods for stakeholder engagement, especially for infrastructure research, is highly specialized and significantly limited. However, some fundamental studies in this domain suggest a small set of key principles to guide stakeholder evaluation approaches (Albritton et al. 2014; Sherman and Ford 2014). Stakeholder evaluation assessments should provide information on the effectiveness of the collaboration, protect anonymity, and they should be time-conscious to generate higher response rates and not overburden collaboration. Assessments also should involve a cyclical and iterative process, so data collection strategies must consider important trade-offs (Goodman et al. 2019). The range of data gathering methods involves trade-offs. For example, surveys can be quick, cost-effective, and anonymous, but they are limited in terms of data depth and interpretation, whereas interviews and open questions are more time-consuming and not always anonymous but can provide more descriptive and in-depth information.

In terms of conceptual frameworks that can help frame data analysis and interpretation, Albritton et al. (2014) identify three key dimensions of stakeholder engagement evaluation: context, process, and impact. *Context* speaks to the situational aspects of the engagement, which for PR100 is represented by the number of Advisory Group members across sectors (e.g., NGOs and industry). *Process* captures procedural aspects of the engagement, such as communication, cohesive organization, and the degree of active collaboration. *Impact* is an outcome-driven dimension related to aspects of the overall stakeholder experience, knowledge mobilization across members and organizations, and broader impacts outside the immediate auspices of the study (e.g., news coverage, social media shares). In this way, these aspects were mapped within the context, process, and impact dimensions in Table 3 along with respective measures and data sources to form a stakeholder evaluation matrix. As described in Section 2.3.2 data gathered directly from PR100 stakeholders through questionnaires were also mapped to this stakeholder engagement evaluation matrix for iterative assessments.

Table 3. Key Dimensions of Stakeholder Engagement Evaluation for PR100

Category 1 focuses on representation and inclusion, Categories 2 and 3 focus on participation and active engagement, and Categories 4 through 6 on project outcomes considering stakeholder engagement. Broader impacts speak to engagement beyond the Advisory Group, such as community-based events or press coverage of PR100.

	Category	Goals	Measurable Outcomes	Data Description
Context	**Representation**	Representation and Inclusion: Adequate number of relevant members from diverse organizations, including the private sector, public sector, universities, and NGOs	• Size of stakeholder group • Number of members by sector and over time	• Zoom/Teams attendance reports • Sign-in sheets • AG member database
Process	**Communication and Effectiveness**	Project content is clearly communicated and effective in terms of comprehension, applicability, receiving stakeholder feedback	• Stakeholder responses regarding the effectiveness of engagement at meetings, presentations, other communications for project progress	• Post-meeting and 6-month evaluation forms • Online community (Mobilize) metrics (e.g., appreciation rates)
	Involvement, Cohesiveness, and Collaboration	Ample space for continuous collaboration and stakeholder activity beyond attending meetings and presentations	• Attendance over time • Stakeholder responses • Ongoing interaction among Advisory Group members and project staff • Data sharing and idea exchange	• Attendance • Online community (Mobilize) summaries: posts, comments, activity, new memberships • Open questions on evaluation forms • Formal memos
Impact	**Stakeholder Satisfaction and Experience**	Improved research and project outcomes that support implementation	• Stakeholder responses in terms of satisfaction with the engagement process, and its outcomes	• Six-month and post-meeting evaluation forms
	Knowledge and Technology Mobilization	Collaborative production of data sets, models, and tools that are highly relevant and actionable for sustainable energy transition goals	• Knowledge transfers (data, tacit insights, reports, insights) • Relevant PR100 data, frameworks, modeling approaches for transition goals	• Data/toolsets sharing log • Mobilize resource downloads • Public- and stakeholder-facing reports

	Category	Goals	Measurable Outcomes	Data Description
	Broader Impact	Dissemination of knowledge, outcomes, and project progress with the public and community at large and open possibility for external feedback	• Public mentions and non-project-initiated media (e.g., news, interviews, community engagement) • Shares • Presentations • Stakeholder-driven dissemination	• Online community (Mobilize) posts and other activity (see 3.1.1.6) • News articles • Blog posts • Social media shares and mention • Site visits • Public webinar attendance

2.3.2 PR100 Approach for Engagement Metrics and Analyzing Feedback

In Year 2, the Advisory Group had more than 100 members, which both represented a significant opportunity for inclusive feedback across several energy-related domains and posed challenges in terms of digesting feedback and assessing the effectiveness of stakeholder engagement processes. This tension highlights the importance of creative, effective, and information-based strategies to make improvements and better facilitate engagement practices.

To document the stakeholder engagement process and establish a framework for continuous evaluation and reflexivity, an approach for establishing metrics and analyzing engagement activities with the Advisory Group was necessary. Based on the size of the Advisory Group, available tools, and feedback needs, we developed a strategy that combined data collected from feedback forms, open-answer questions, user activity in the Puerto Rico Energy Recovery and Resilience online community on the Mobilize application and Advisory Group participation in meetings and events. Post-Advisory Group meeting evaluations were administered via a form with both Likert-style and open-ended questions for quantitative and qualitative analysis, and due to their direct nature in respect to assessing engagement, were the primary source of data for engagement evaluation.

We framed data from the post-meeting evaluation forms, attendance records, and other sources, in terms of the three engagement evaluation dimensions discussed in Section 2.3.1: context, process, and impact. For context, we took stock of the disciplinary and professional background by subsetting the list of Advisory Group members by industry that we updated routinely. For process and impact, we leveraged the post-meeting evaluation forms by designing questions that could illuminate these aspects as the project unfolded and iterative discussions with the Advisory Group progressed. The evaluation processes began with the 6-month Advisory Group meeting and continued for subsequent regularly held meetings, and results were routinely reported internally to laboratory staff to focus on improving engagement processes. Evaluations were also occasionally shared with Advisory Group members during meetings and in slides summarizing stakeholder engagement activities and demonstrating how feedback is incorporated.

2.3.3 Evaluation Results for Engagement Context, Processes, and Impact

Throughout the study, the project team collected and maintained data pertaining to stakeholder membership, participation, and feedback. The primary resources used to evaluate engagement processes were the post-meeting evaluation forms that occurred from the 6-month Advisory Group meeting and continued at monthly to bimonthly rates for the duration of the project. Generally, the cyclical engagement and evaluation processes were rewarding, but maintaining participation across the stakeholder membership in the evaluation procedures was a persistent challenge. For this reason, data were sometimes limited, and efforts were made to improve participation for engagement evaluation feedback forms after key meetings.

In this way, the iterative results were reported internally, which enabled lessons to be learned as the project progressed. A few key insights emerged from analyzing stakeholder responses over the 2-yr engagement period, the most persistent of which was the importance of respondents and their communities seeing evidence of their feedback incorporated into the project. In response, and to ensure accountability in the incorporation of stakeholder feedback, a record of Advisory Group member suggestions that were incorporated into analyses and interpretation was maintained and shared with Advisory Group members during presentations in subsequent meetings and in this report (Section 2.1.2.1.1, page 20). Remaining aspects of stakeholder engagement contexts, processes, and impacts based on feedback data are discussed in this section.

2.3.3.1 Advisory Group Composition by Industry Over Time

We took stock of the Advisory Group composition in October 2022 and roughly 6 months later in April 2023. Figure 9 shows stakeholder representation across sectors from academia to utility organizations and their respective subsectors near the end of Year 2. A few disengagements and several additions occurred within this period as the total Advisory Group membership grew from 92 to 117 individuals. Representation grew primarily in the legal, finance, and management consulting areas of the private sector, federal government agencies, and in the community organization-oriented NGOs. These changes reflect cues taken from the initial stocktaking of the Advisory Group composition with respect to sectors and subsectors, along with feedback regarding important voices to include as suggested by Advisory Group, community, and project members. Attendance was fairly stable over time considering slight oscillations between meetings in terms of both the total number of attendees and representation by sector; the average number of attendees for regular meetings was 46 by October 1, 2023. As reflected by the composition of the Advisory Group, NGO members regularly led representation in meetings, followed by the private sector toward the end of Year 2. However, representation in topical and ad hoc meetings were more prominently represented by stakeholders specialized in respective sectors.

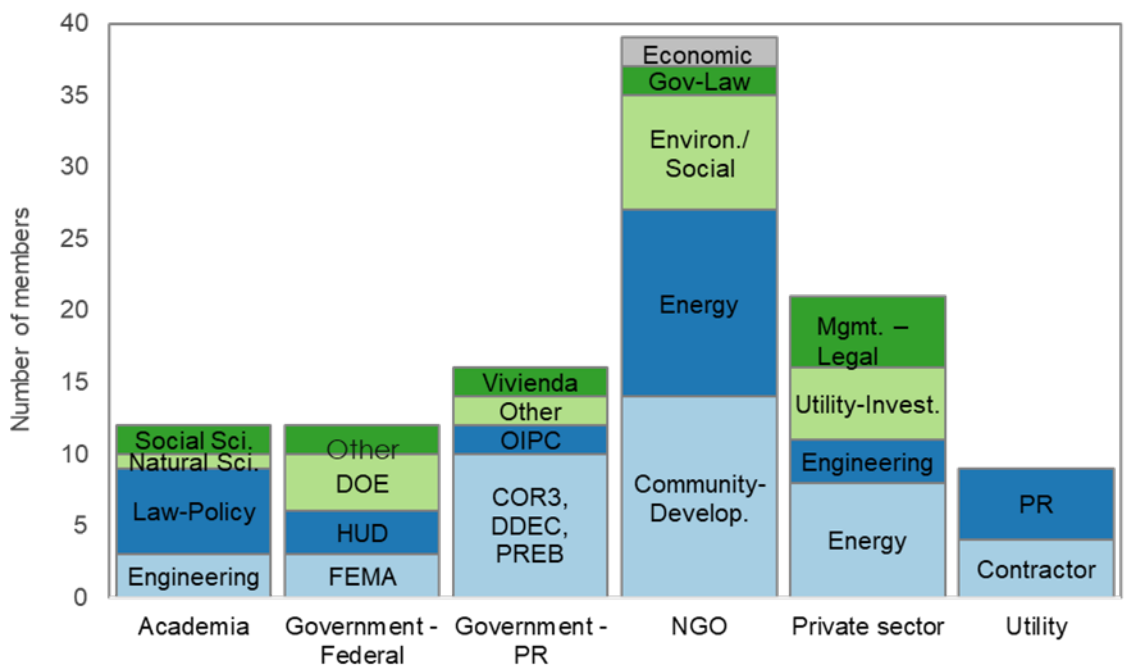

Figure 9. PR100 stakeholder composition by sector (i.e., industry) and subsector (labeled directly) in October 2023

2.3.3.2 Stakeholder Evaluations of Engagement Processes and Impacts

Advisory Group members were asked to complete online evaluation forms after each full group meeting that included both Likert-style questions that could be quantified and open-ended questions that allowed respondents to express feedback via text. We transformed Likert responses to scores from 0 to 1 (0 = lowest and 1 = highest). Overall, the stakeholder evaluations engagement processes and impacts ranged from 0.63 to 0.94 for individual meetings with an overall average score of 0.77 (see Appendix C, Table C-1, page 674). However, as mentioned in the beginning of the current section (Section 2.3.3), participation in engagement evaluation was sometimes low, specifically for the January and June 2023 set of forms, which garnered the least participation with only two and seven evaluation responses each, respectively.

Toward the second half of Year 2, ratings representing the effectiveness and clarity of the meeting content decreased. Based on the qualitative feedback from stakeholders and reflections among the laboratory team, we deemed this to be due to challenges surrounding technical presentations and detailed results for a diverse audience. As Advisory Group meetings focused more on refining model parameters and results, it was necessary to balance (1) the level of detail desired by stakeholders with different technical backgrounds like engineering and (2) other kinds of details and higher-level takeaways desired by those with policy, management, and other kinds of backgrounds. In response, the PR100 project team iteratively discussed several strategies to improve presentations and the overall effectiveness of meetings. Working strategies included offering optional, topical meetings to present and discuss detailed results and assumptions, and aiming for higher-level takeaways and discussions during full group meetings.

Qualitative data from the evaluation forms were divided into two feedback streams: suggested topics to cover in future meetings and engagement improvements. Qualitative results were addressed by the stakeholder engagement task team members by setting agendas for future meetings and developing strategies to improve engagement processes. Topical suggestions varied greatly, but recurring topics centered on energy justice, community outreach and participation, post-PR100 implementation, and several economic aspects of the energy transition (e.g., net metering and funding).

Key Finding: Evaluation of engagement processes revealed appreciative reactions to the level of detail and extensive content of an energy justice focused Advisory Group meeting in June 2023, several important discussion topics, and the need for improvements to visualizations and the balance between time spent on discussions versus presentations.

3 Energy Justice and PR100

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Section Summary

A key focus of PR100 was to chart possible pathways toward a renewable energy future for Puerto Rico based on priorities and perspectives of stakeholders and grounded in principles and practices of energy justice. This effort began by ensuring PR100 itself involved stakeholders and adhered to the practices that support a just process for energy planning.

In this section, we discuss definitions of energy justice and associated pillars, principles, and academic frameworks that informed this aspect of the study. We describe our approach to integrating energy justice principles throughout the study, highlight energy justice priorities identified by stakeholders, and present results of a literature review conducted to help ground the study in energy justice. Finally, we provide an overview of our understanding of energy justice considerations in the Puerto Rico context, and we discuss topics related to the circular economy for energy materials in the context of energy justice for Puerto Rico.

Puerto Rico Context

- Utility customers in Puerto Rico pay more on average for electricity than those in the 50 U.S. states (Figure 11), and power outages are vastly more frequent and of longer duration than in the 50 states. In 2021, PREPA customers experienced an average of 1,559 minutes of service interruption compared with 136 minutes in the 50 states (11.5 times greater) and 7.8 interruptions per year on average compared with 1.1 interruptions in the 50 states (7.1 times greater) (FOMB 2023b); (Table 5).
- The average household energy burden, or percentage of income spent on energy, is higher in Puerto Rico than all other states except Vermont (both are 4%, compared with 1%, 2%, or 3% in all other states) and higher than the U.S. average for all income groups (Figure 12). Average energy burden for very low-income households (0%–30% area median income) in Puerto Rico is particularly high (35%) as compared with the U.S. average (12%).
- All but a few census tracts in Puerto Rico are considered disadvantaged communities as defined by the White House Council on Environmental Quality because they are overburdened and underserved (Figure 20).

Key Findings

- Energy justice themes prioritized by Advisory Group members include energy access, affordability, reliability, and resilience; community participation; economic and workforce development; siting and land use; environmental and health effects; and public sector implementation.
- The literature on energy justice is growing and includes academic publications as well as reports, websites, blogs, videos, and other materials. The history of energy system injustices in Puerto Rico and local knowledge on problems and solutions is increasingly well documented. Still, there is an ongoing need to deepen our understanding of energy justice concerns and priorities in Puerto Rico.

Considerations

- Working toward energy justice for Puerto Rico involves prioritizing access to affordable, resilient electricity and high-quality energy sector jobs and economic opportunities for the most vulnerable people and communities, such as rural, remote, low-income, and people with disabilities.
- An important way to work toward a just and inclusive energy transition for Puerto Rico is by developing implementation structures and processes that foster ongoing engagement and participation of communities and industry sectors, and take into consideration their unique and common impacts, aspects, and priorities, to ensure broad and meaningful stakeholder participation in the planning, decision-making, and implementation of the transition to 100% renewable energy.

3.1 Definitions, Pillars, and Principles

The definition of energy justice used in this study is "... the goal of achieving equity in both the social and economic participation in the energy system, while also remediating social, economic, and health burdens on those historically harmed by the energy system..." (Baker, DeVar, and Prakash 2019). This vision was foundational for PR100 and was reflected in the explicit goal to ground the study in principles and practices of energy justice.

While these concepts and principles have been richly discussed in the academic and practice-oriented literature, energy justice is a relatively recent intellectual domain that is still developing. The pace of innovation in energy justice is in keeping with the pace of change in energy technologies and the implementation of them in transitioning local, regional, and global portfolios of energy resources. Consequently, multiple intersecting theoretical frameworks can be drawn on to form the basis for thinking about energy justice in Puerto Rico as the Commonwealth charts its path toward a renewable energy future. See Appendix D for a discussion of the theoretical foundation of energy justice in PR100.

Energy justice grew in part out of related movements in environmental justice (McCauley et al. 2013). Environmental justice derives from activism for environmental protection and remediation of past environmental damages that have disproportionately affected marginalized communities' status due to class, race, or ethnicity. Energy justice represents the basic application of similar principles, including the remediation of past inequities, to the domain of energy production and distribution.

3.1.1 Pillars of Energy Justice

The literature points to five main pillars or tenets of energy justice, illustrated in Figure 10:

- **Procedural Justice:** broad and meaningful participation by all people and groups in framing issues and making decisions related to the energy system; engagement of all stakeholders in a nondiscriminatory way; centering on concerns of marginalized communities (K. Jenkins et al. 2016)
- **Recognition Justice:** recognition and respect of divergent perspectives and cultural and local knowledge; acknowledgment of marginalized and disadvantaged communities' experiences in relation to energy systems (Heffron and McCauley 2017)
- **Distributive Justice:** equitable distribution of energy system benefits and burdens, including exposure to risk, across all members of society, regardless of income, race, and so on (Baker, DeVar, and Prakash 2019)
- **Restorative Justice:** efforts to repair harms to communities and the environment caused by energy activities and identify opportunities for prevention of future harm (Finley-Brook and Holloman 2016).
- **Transformative Justice:** in which structures, policies, and practices that perpetuate inequities are eliminated, and energy systems undergo systemic change based on social mobilization and political change to be designed and managed with greater participation by all stakeholders for the benefit of future generations (Lee and Byrne 2019).

Taken together, these principles guide PR100 to ensure energy justice is a driving consideration in possible pathways toward Puerto Rico's renewable energy transition and future.

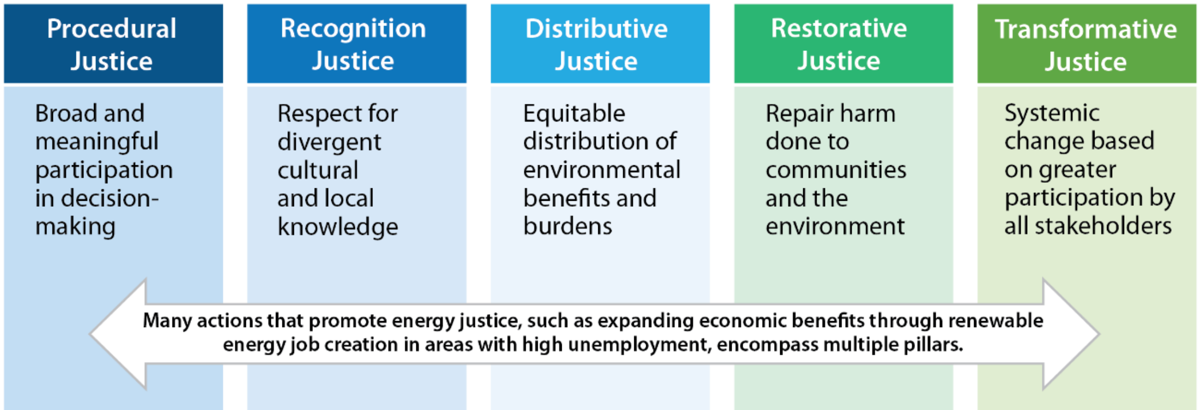

Figure 10. Five pillars of energy justice

Sources: Jenkins et al. (2016), Heffron and McCauley (2017), Baker et al. (2019), and Lee and Byrne (2019)

3.2 Energy Justice Integration in PR100

We sought to ensure energy justice principles were integrated throughout PR100. We worked closely with members of the Advisory Group (Section 3.1.1.2) and project partners from Hispanic Federation and the University of Puerto Rico at Mayagüez (UPRM) to understand their energy justice priorities and what a just energy transition for Puerto Rico might entail. In close work with UPRM students and faculty we contributed to and benefitted from extensive discussions about energy justice principles and metrics, and their real-world implications for the people of Puerto Rico. This collaboration resulted in the development and documentation of new energy justice metrics, some of which are described in this report (Section 14.2, page 561) and a forthcoming memo from UPRM (M. J. Castro-Sitiriche et al. 2023).

We held internal discussions with each modeling team to explore how their work would be shaped by and reflect energy justice concerns, how to integrate energy justice principles into their analyses, and to consider the implications of their work related to each of the energy justice pillars. The result of these discussions with stakeholders including the project team was a view of energy justice issues and priorities in Puerto Rico, and an inventory of the ways they could be better addressed in PR100.

We presented this process at an Advisory Group meeting on the topic of energy justice in June 2023, including our framework for understanding energy justice and recap of discussions with each of the PR100 modeling teams about how energy justice informed their work. Time was also allotted for questions and discussions from the Advisory Group, whose input was invaluable to constructing the final phases of the project, the products of the project, and the report.

The results of this process included:

- A better appreciation of the obligations of procedural justice, especially in terms of transparency in documenting and communicating the methods used to develop modeling scenarios and gathering input on scenarios of interest to stakeholders data to construct them

- A fuller accounting of the benefits and burdens of the energy system being modeled, and stakeholder valuation of these benefits and burdens, reflecting distributive justice and recognition justice
- A better view of the past challenges associated with the energy system and the effect on the people of Puerto Rico, reflecting restorative justice and further informing scenario design and our ability to address stakeholder concerns about the future energy system
- A recognition of the role that PR100 could play in informing discussions about Puerto Rico's energy future, including how PR100 analysis results, data, and tools could be useful for a wide array of implementers. This helped shape the products of the study and how they were disseminated, such that PR100 would be an effective resource for the people of Puerto Rico to remake their energy system, including how it is designed and managed, to achieve the goals of transformative justice and energy democracy.

Results of the process of integrating energy justice throughout the study are reflected in the structure of this report. Some sections include a discussion of energy justice integration and/or implications as they relate to the section topic (see Sections 6.3, 7.2, 8.3, 12.3.3). Additionally, the overall structure of the report and its contents were designed with our commitment to energy justice in mind. Rather than a technical report, written by and for outside analysts, modelers, and researchers, we offer this PR100 report and associated materials as a package from which stakeholders in all roles can learn, and with which they can enrich their visions of a renewable energy transition for the entire archipelago.

> **Key Finding:** Engaging in a deliberate process of discussing energy justice frameworks with each topic lead and determining how to more explicitly call out or integrate energy justice ensured the study as a whole was more oriented as a resource for working toward energy justice in Puerto Rico and addressing stakeholders' keen interest in this topic.

3.3 Energy Justice Priorities Identified by Stakeholders

In April 2022, during the third meeting of our Advisory Group, we held small group discussions on the topic of energy justice. Below is a summary of concepts, by theme, that emerged from answers to the question: What is your vision for a just energy transition for Puerto Rico?

- **Energy access, affordability, reliability, and resilience.** Ensure equitable access to affordable, reliable, resilient, renewable energy for all households and businesses, including underserved and rural communities; ensure the cost of energy is not a financial burden.
- **Community participation.** Ensure the study incorporates local knowledge and results are shared in a way that everyone can understand them; recognize and include underrepresented Puerto Ricans and communities in the decision-making processes.
- **Economic and workforce development.** Design the energy transition to drive economic development; a just transition moves our economy away from fossil fuels and toward solar energy in Puerto Rico while providing just pathways for workers to transition to high-quality work.
- **Siting, land use, and environmental and health effects.** Use the existing built environment footprint first; ensure the energy transition does not negatively affect the development of other essential services like food production; consider appropriate balance of land uses (e.g., do not sacrifice agricultural land for energy development).

- **Public Sector Implementation:** Enable greater transparency about use of federal funds and timing; provide access to funds by municipalities and others for local resilience projects; ensure PREPA and LUMA consider PR100 results and input from local energy experts regarding contracting and selection process for federal funds.

Key Finding: Energy justice themes prioritized by Advisory Group members include energy access, affordability, reliability, and resilience; community participation; economic and workforce development; siting and land use; environmental and health effects; and public sector implementation.

3.4 Grounding the Study in Energy Justice: Literature Review

As part of the effort to ground PR100 in energy justice, we conducted a literature review and created a database of resources to critically examine existing research on energy justice broadly and in Puerto Rico, highlighting key themes, disparities, policy implications, and community engagement strategies. The purpose of the literature review was to ensure we were working from and basing the study on a shared understanding of principles and practices of energy justice. We conducted an in-depth review of academic articles, reports, policy documents, and other relevant sources to investigate the concept of energy justice, and key issues and challenges in the Puerto Rico context. We periodically posted updates to the database to our online community and invited members to suggest additional resources to include. In the database we indicated which resources were authored by Advisory Group members to lift up sources of local knowledge and flagged resources with a Puerto Rico focus. As of September 2023, there were 83 resources in Energy Justice Resources database.[43]

Key Finding: The literature on energy justice is growing and includes academic publications as well as reports, websites, blogs, videos, and other materials. The history of energy system injustices in Puerto Rico and local knowledge on problems and solutions is increasingly well documented. Still, the need to deepen our understanding of energy justice concerns and priorities in Puerto Rico is ongoing.

We employed a thematic analysis approach to identify recurring themes, concepts, and patterns within the literature. We grouped relevant information based on categories such as energy access, affordability, environmental equity, policy implications, and community involvement. We identified 11 key themes by which to categorize the resources (Table 4). Some resources cut across multiple themes, which we acknowledged in the database. The literature methods and detailed thematic analysis are presented in Appendix E.

[43] Publicly accessible through our password-protected PR Energy Recovery and Resilience online community on the Mobilize platform: https://pr-energy.mobilize.io/main/groups/49360/lounge/resources?path=%2FEnergy%20Justice

Table 4. Energy Justice Themes and Descriptions

Themes	Description
Academic frameworks	Concepts, tenets, and academic frameworks on the topic of energy justice
Case studies	Case studies and experiences of specific communities across the energy justice themes identified
Economic and workforce development	Impacts on jobs created or lost, workforce development and training, and economic participation in the context of energy justice
Energy access	Includes affordability, reliability, resilience, access to new technology, and energy efficiency upgrades
Energy democracy	Community ownership, public engagement, access to decision-making, program and policy design
Environmental and health impacts	Impacts to human and environmental health associated with the energy system, including disparities in exposure to pollution
Foundational works	Core works as identified by the research team
Infrastructure interdependencies	Transportation, telecommunications, water, and wastewater as it pertains to energy justice
Land use and siting	Decision-making processes related to where energy infrastructure is sited, with a focus on energy justice and considerations and social acceptance; includes concepts of fairness, transparency, and public decision-making and topics including appropriate use of agricultural lands
Puerto Rico	Pertain to or reference Puerto Rico
Utility actions	Program administration, grid tariff regulatory reform, tariff on-bill financing, utility decarbonization plans

3.5 Energy Justice Considerations for Puerto Rico

Addressing energy injustices in Puerto Rico requires an understanding of the energy justice context. In this section, we discuss—at a high-level—facets of energy justice in Puerto Rico including energy access and affordability, vulnerabilities of disadvantaged communities, and the use of data visualization tools to access information and inform solutions. Within PR100, we also conducted an in-depth resilience analysis using a social burden metric and generated scenario maps to visualize critical service needs by area (see Section 5.2). We also highlight a few examples of how local organizations are currently advancing energy justice in Puerto Rico.

3.5.1 Energy Affordability and Reliability

Access to affordable, reliable electricity is a principal energy justice issue in Puerto Rico. Utility customers in Puerto Rico pay more on average for electricity than those in the 50 U.S. states (Figure 11), and power outages are vastly more frequent and of longer duration than in the 50 states. In 2021, PREPA customers experienced an average of 1,559 minutes of service interruption compared with 136 minutes in the 50 states (11.5× greater), and 7.8 interruptions per year on average compared with 1.1 interruptions in the 50 states (7.1× greater) (FOMB 2023b); See Table 1).

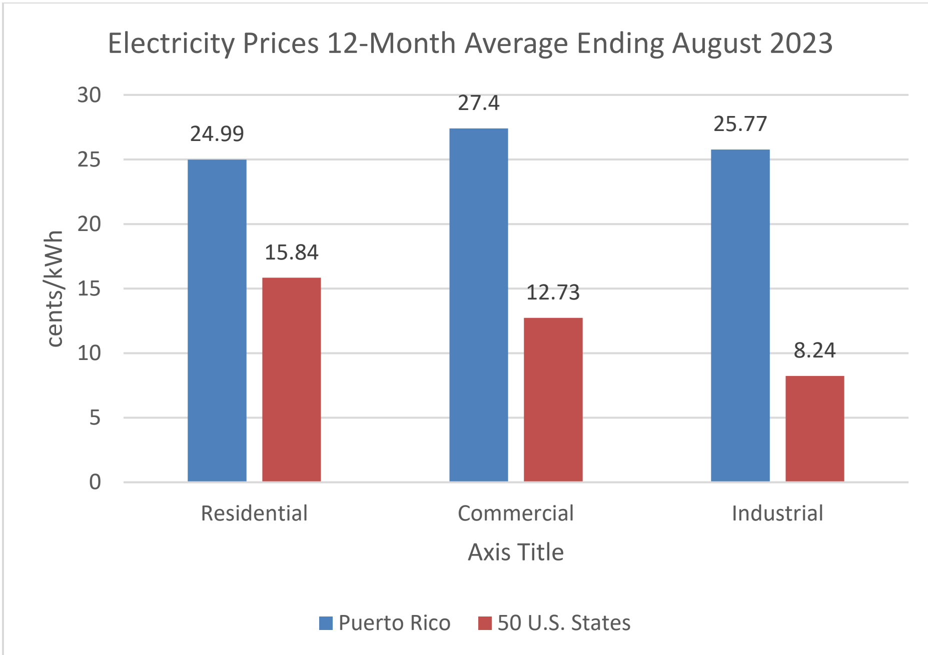

Figure 11. Electricity prices in Puerto Rico and the 50 U.S. states by customer type, 12-month rolling average ending August 2023

Data Source: EIA (2023a; 2023b)

Table 5. Frequency and Duration of Power Outages in Puerto Rico Compared With the 50 U.S. States in 2021

Adapted from FOMB 2023

Reliability Metric	PREPA Calendar Year 2021	IEEE U.S. Median, Calendar Year 2021	Gap: PREPA versus U.S. Median
System Average Interruption Duration Index (SAIDI) *Minutes per year*	1,559	136	11.5×
System Average Interruption Frequency Index (SAIFI) *Number of interruptions per year*	7.8	1.1	7.1×

The average household energy burden, or percentage of income spent on energy, is higher in Puerto Rico than all other states except Vermont (both are 4%, compared with 1%, 2%, or 3% in all other states),[44] and higher than the U.S. average for all income groups (Figure 12). Average energy burden for very low-income households (0%–30% area median income) in Puerto Rico is particularly high (35%) as compared with the U.S. average (12%).[45]

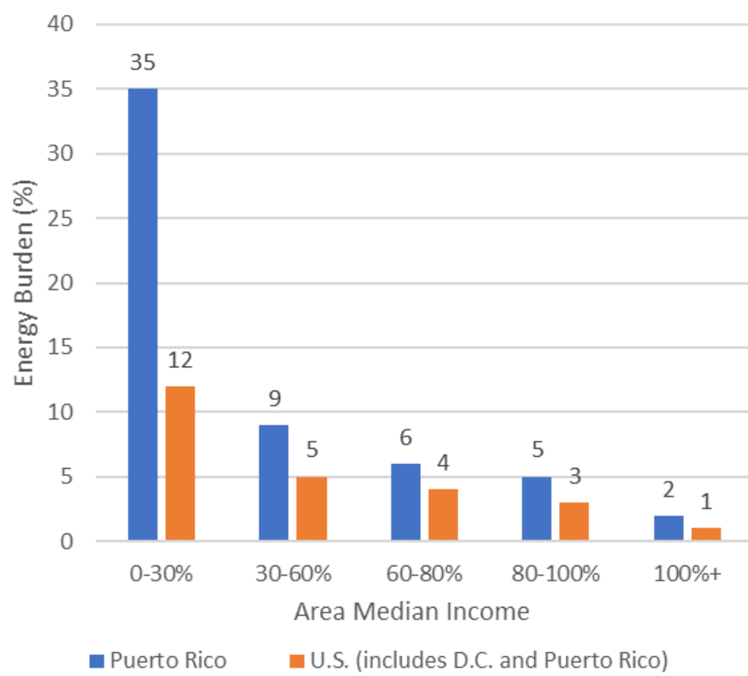

Figure 12. Average energy burden in Puerto Rico and 50 U.S. states (includes Puerto Rico and the District of Columbia) by income group

Data Source: Low-income Energy Affordability Data (LEAD) Tool, accessed October 15, 2023

A map of energy burden by census tract for all income levels combined in Puerto Rico (Figure 13) reveals energy burden of 8% or greater in tracts around San Juan, Ponce, and other various locations across the main island.

[44] "Low-Income Energy Affordability Data Tool," https://www.energy.gov/scep/slsc/lead-tool, accessed October 15, 2023.
[45] Data for the LEAD Tool comes from the U.S. Census Bureau's American Community Survey 2020 Public Use Microdata Samples. Methodology is available at https://lead.openei.org/docs/LEAD-Tool-Methodology.pdf

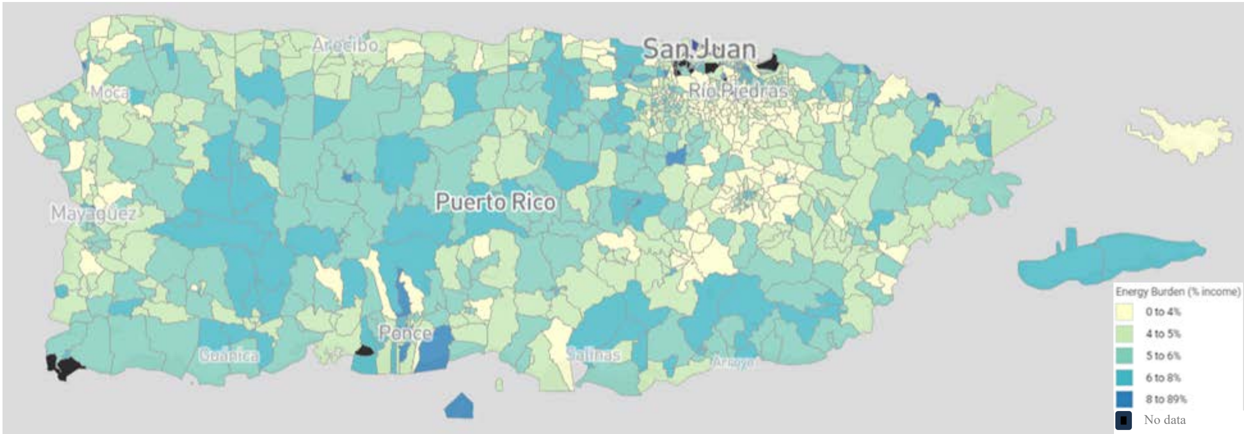

Figure 13. Energy burden, or percentage of household income spent on energy, in Puerto Rico by census tract for all income levels

Source: LEAD Tool, accessed October 15, 2023

3.5.2 Energy Access

Analysis of electricity service restoration time after long-duration power outages by region illustrates disparities in energy access by region. Figure 14 shows restoration time by region of Puerto Rico after Hurricane Maria in 2017 (a Category 5 hurricane), and Figure 15 shows restoration time by region after Hurricane Fiona in 2022 (a Category 1 hurricane accompanied by historic rainfall, landslides, and flooding), five years (and billions of dollars in federal funding commitments later). Contrasting the two events highlights how long communities across Puerto Rico waited for power to be restored after Maria and how much more quickly the system was restored after Fiona.

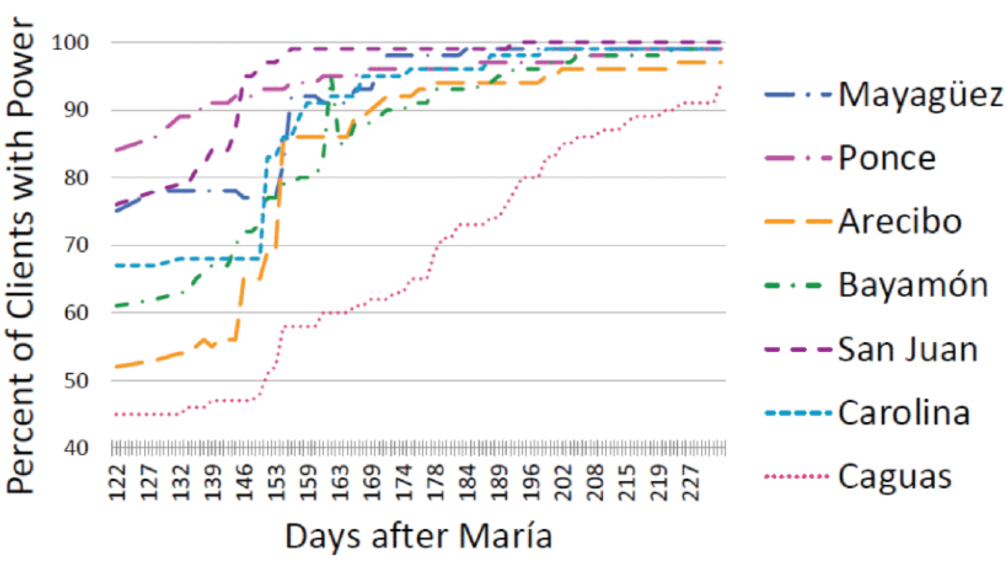

Figure 14. Power restoration over time after Hurricane Maria by region of Puerto Rico

M. Castro-Sitiriche, Cintrón-Sotomayor, and Gómez-Torres (2018)

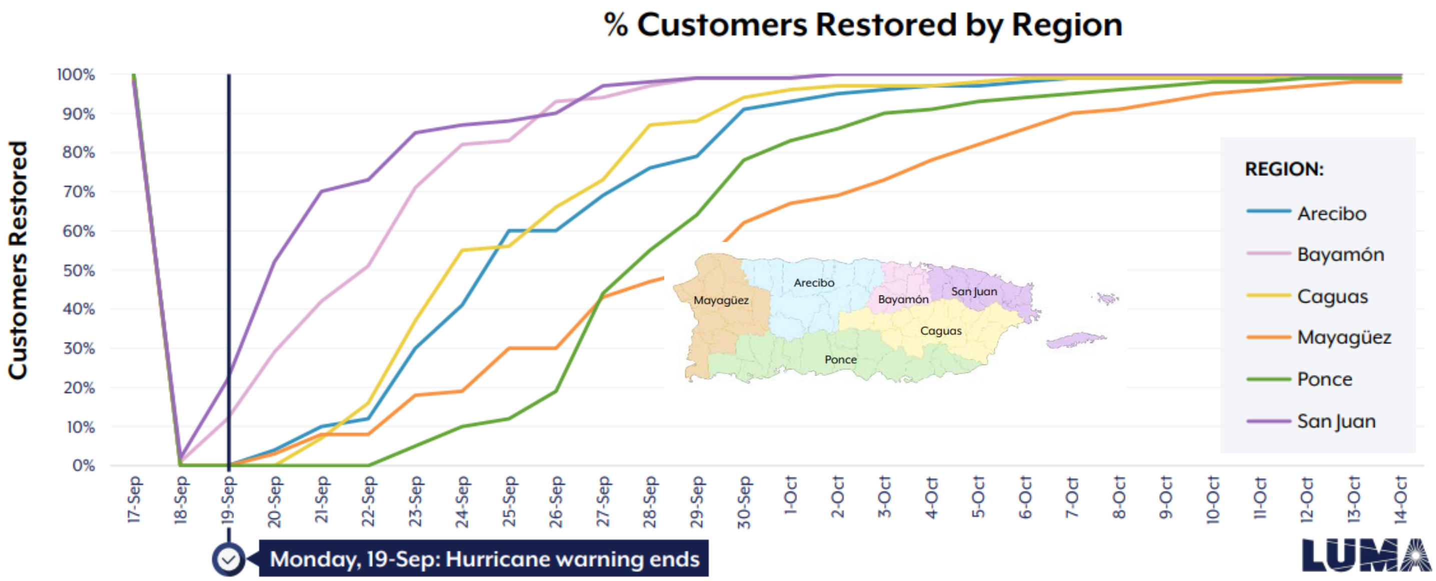

Figure 15. Power restoration over time after Hurricane Fiona by region of Puerto Rico

Source: LUMA (2022)

As part of our work with UPRM on PR100, Castro-Sitiriche et al. (forthcoming) recommend placing special emphasis on the last 5% of customers restored after outages to effectively identify mitigation strategies to overcome vulnerability to long-duration power outages (Figure 16). UPRM contributors proposed customer hours of lost electricity service (CHoLES) as an important metric for power system resilience and to establish a baseline measure of regional impact; unlike grid resilience, the CHoLES metric can take into account community resilience measures such as solar and storage systems that operate independently of the grid during an outage.

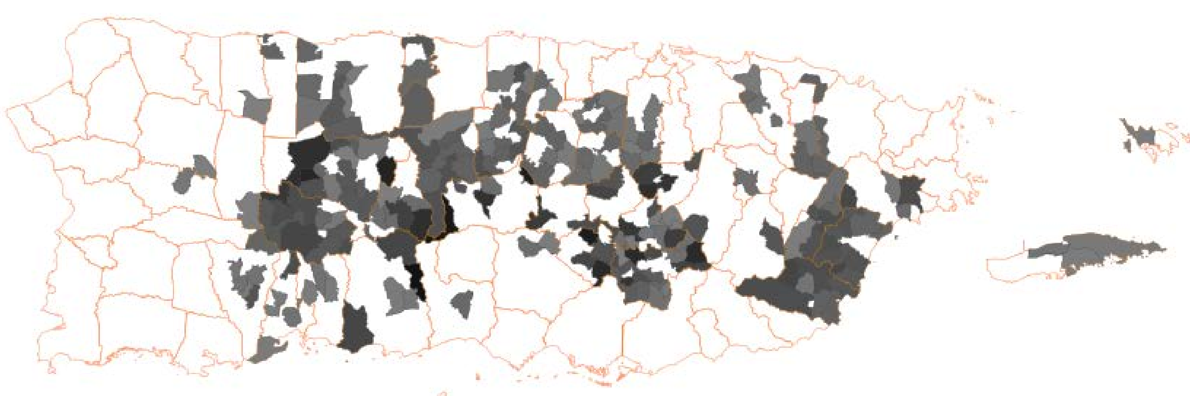

Figure 16. Communities with power restored more than 197 days after Hurricane Maria (last 5% of customers)

Source: Castro-Sitiriche et al. (2023)

UPRM contributors also proposed a hypothetical scenario in which 200,000 utility customers who were among the last to have had power restored after Maria had islandable rooftop solar and storage systems as a basis for comparison using the CHoLES metric. In Figure 17 and Figure 18, the green-shaded area shows how the number of days until all customers had power would change if the 200,000 customers who were last to have power restored had islandable rooftop solar and storage systems. According to this analysis, the number of days before 100% of customers had power restored could have been 156 days if grid power was supplemented with islandable solar and storage systems —compared to 329 days with only grid power (Figure 17). Figure 18 shows that CHoLES for grid power supplemented with islandable solar and storage for 200,000 households could have been 2,445 million CHoLES as compared with only grid power of 3,336 million CHoLES after Hurricane Maria.

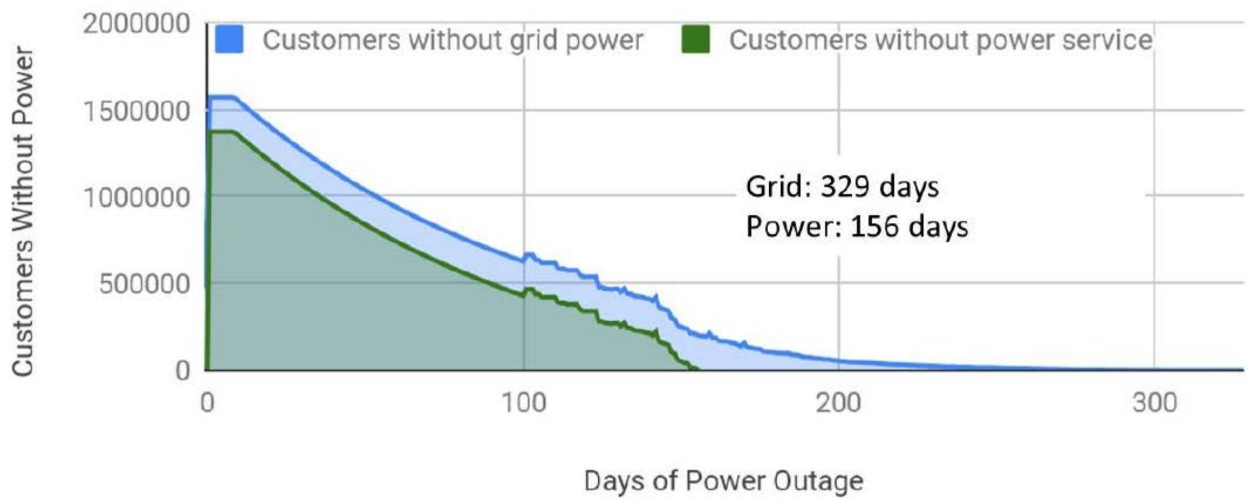

Figure 17. Number of days customers were without grid power and without power service after Hurricane Maria in a hypothetical scenario where 200,000 more households had islandable rooftop solar and storage

Source: Castro-Sitiriche et al. (2023)

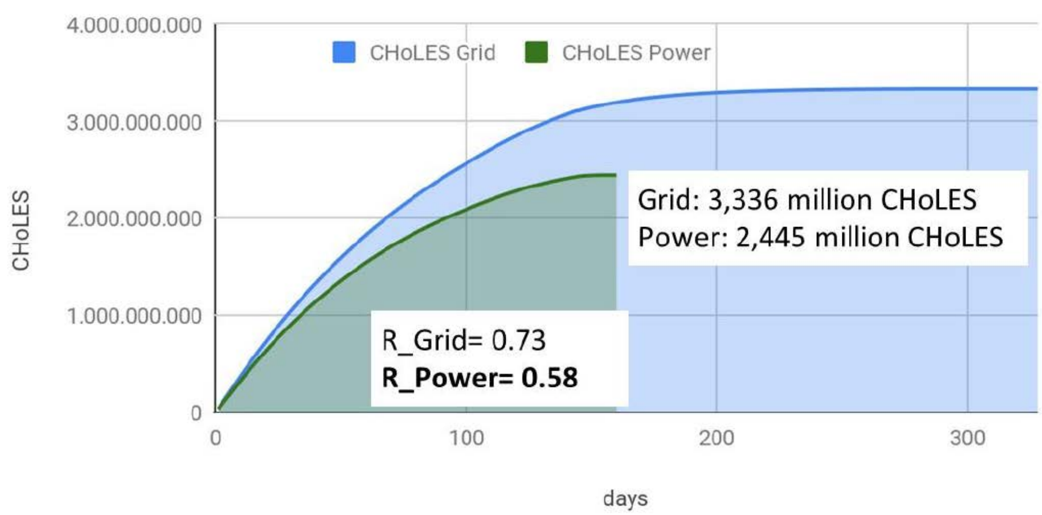

Figure 18. CHoLES for grid power and power service after Hurricane Maria in a hypothetical scenario where 200,000 more households had islandable rooftop solar and storage

Source: Castro-Sitiriche et al. (2023)

UPRM contributors underscore the importance of engaging with communities that historically have been among the last 5% to have power restored after long-duration outages to identify and address their unique energy resilience needs and posit that the benefit of increased power system resilience can be measured in CHoLES.

Consistent with this approach, NREL developed an interactive map of last-mile communities in Puerto Rico (Figure 19) in support of defining eligibility for the U.S. Department of Energy (DOE) Puerto Rico Energy Resilience Fund program. Eligible beneficiaries of the program include, "(a) very low-income single-family households where an individual with an energy-dependent disability resides (no geographic restriction); or (b) very low-income single-family households located in a last-mile community, which DOE defines as, "a census block that (a) has a high percentage of very low-income households, and (b) experiences frequent and prolonged power outages."[46]

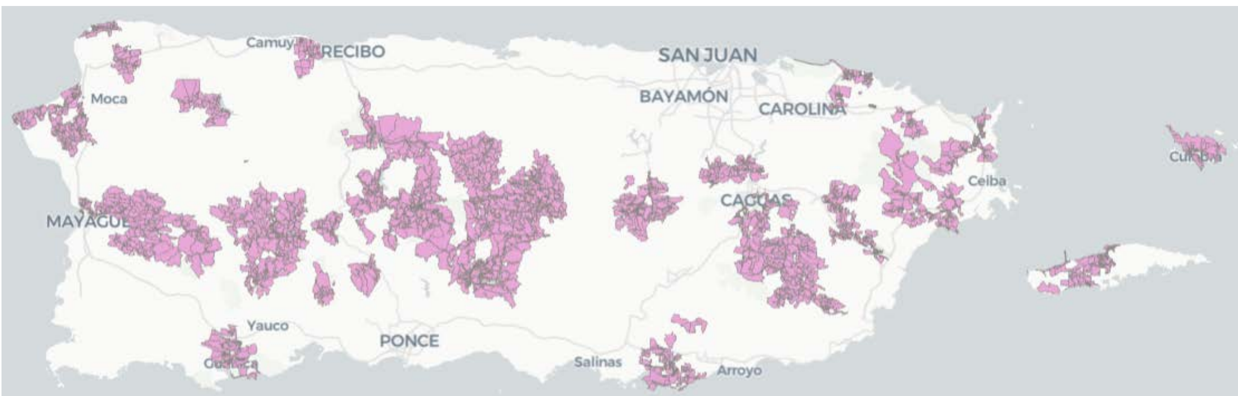

Figure 19. Last-mile communities in Puerto Rico as defined by DOE for the Puerto Rico Energy Resilience Fund Program

"Interactive Puerto Rico Last Mile Community Map," DOE, https://clausa.app.carto.com/map/9d2a8e25-2f54-4f88-b95b-7151739bd3c7

3.5.3 Intersecting Vulnerabilities of Disadvantaged Communities

Many communities across Puerto Rico experience intersecting vulnerabilities that highlight a need to increase resilience, restore past harms, and advance energy justice. The Climate and Economic Justice Screening Tool (CEJST)[47] can be used when engaging with communities to understand energy justice indices and multifactorial vulnerability at the local level. The tool combines key indicators to identify census tracts defined by the White House Council on Environmental Quality as disadvantaged communities because they are overburdened and underserved.[48] Clicking on a census tract in the tool reveals how that community is affected by a variety of burdens in seven categories: climate change, energy, housing, legacy pollution, transportation, water and wastewater, and workforce development. Census tracts are considered

[46] "Frequently Asked Questions on the Puerto Rico Energy Resilience Fund 2023 Funding Opportunity Announcement," DOE, https://www.energy.gov/gdo/frequently-asked-questions-puerto-rico-energy-resilience-fund-2023-funding-opportunity. For this program DOE defines a very low-income household as one, "in which at least one individual is enrolled in or receives benefits from one or more of the following government assistance programs: Low-Income Home Energy Assistance Program (LIHEAP), Nutrition Assistance Program (NAP), or Temporary Assistance for Needy Families (TANF)."

[47] CEJST is a product of the White House Council on Environmental Quality. See https://screeningtool.geoplatform.gov/en#3/33.47/-97.5.

[48] "About," Climate and Economic Justice Screening Tool, https://screeningtool.geoplatform.gov/en/about

disadvantaged if they meet one burden threshold *and* the associated socioeconomic threshold (low income for the first six categories and high school education for workforce development). Figure 20 shows that all but a few census tracts in Puerto Rico are considered disadvantaged communities.

Figure 20. Disadvantaged communities in Puerto Rico

Source: CEJST, accessed October 15, 2023. A few circled road numbers appear at this extent of the map.

Figure 21 shows a census tract in the Municipality of Guayama in southeastern Puerto Rico (population: 5,186) that in addition to being in the 98th percentile for low-income (households where income is less than or equal to twice the federal poverty level, not including higher education students), and the 93rd percentile for energy cost (average annual energy costs divided by household income) is also affected by proximity to legacy pollution (93rd percentile for proximity to Risk Management Plan[49] facilities and 97th percentile for proximity to Superfund[50] sites). In the workforce development category, this community is also in the 99th percentile for poverty (share of people in households where income is at or below 100% of the federal poverty level), and 37% of people 25 years or older in the community do not have a high school diploma.

[49] "Risk Management Program (RMP) Rule," EPA, https://www.epa.gov/rmp
[50] "Superfund," EPA, https://www.epa.gov/superfund

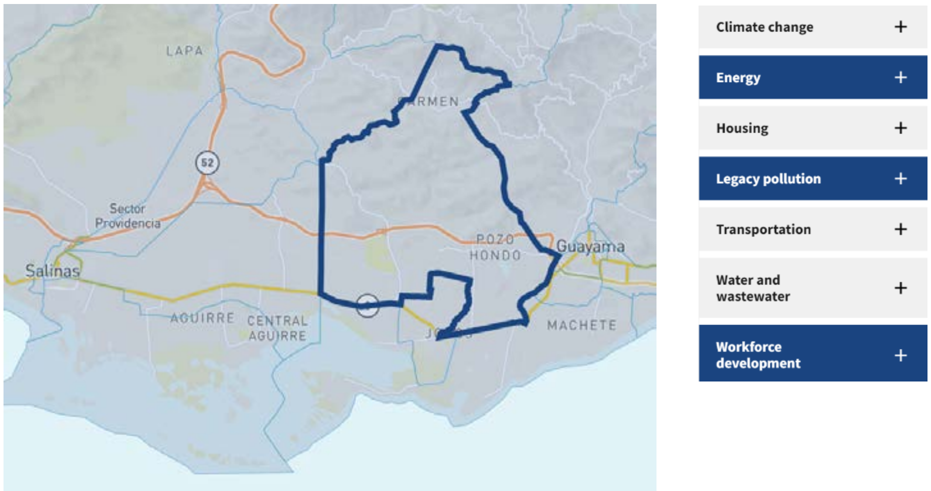

Figure 21. Example of a disadvantaged community in Guayama, Puerto Rico, affected by energy burden, legacy pollution, and workforce development challenges

Source: CEJST, accessed October 15, 2023

Figure 22 shows a census tract in the Municipality of Loiza in northeast Puerto Rico, where in addition to low income and unemployment in the 99th percentile and poverty in the 98th percentile, the projected flood risk is very high (92nd percentile), as are energy cost (95th percentile) and lack of indoor plumbing (97th percentile).

Figure 22. Example of a disadvantaged community in Loiza in northeastern Puerto Rico, affected by climate change, energy burden, housing, and workforce development challenges

Source: CEJST, accessed October 15, 2023

Zooming in on these example communities highlights energy justice opportunities that address needs at the local level, such as increasing access to affordable, renewable energy to decrease the cost of energy; reducing or eliminating pollution from fossil fuel-based energy to address past harms; and promoting workforce development through new jobs in the renewable energy sector.

Another mapping tool that enables assessment of environmental hazards and social vulnerability is the Environmental Justice Screening and Mapping Tool (EJScreen).[51] It combines environmental and demographic data to identify areas with potential environmental justice

[51] EJScreen was developed by the U.S. Environmental Protection Agency (EPA). See https://www.epa.gov/ejscreen.

concerns. While EJScreen primarily focuses on the 50 U.S. states, it can still provide useful information for Puerto Rico by identifying areas that might be disproportionately burdened by environmental hazards, including data on air quality, water quality, hazardous waste sites, and proximity to polluting facilities, such as Superfund sites (Figure 23). By using EJScreen, policymakers, community-based, and environmental organizations in Puerto Rico can identify areas with the highest environmental justice concerns to help target interventions such as pollution reduction initiatives, infrastructure improvements, or community development projects, to address the specific needs of vulnerable communities.

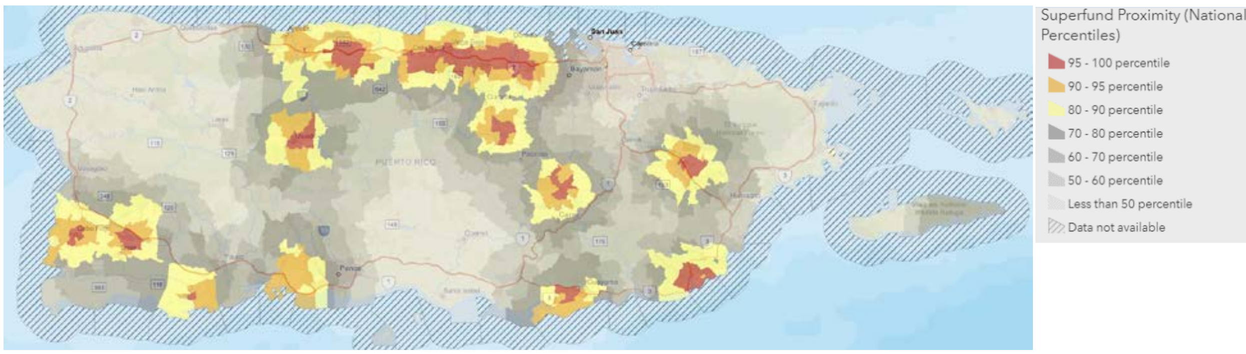

Figure 23. Communities in proximity to Superfund sites in Puerto Rico

Source: EJScreen, accessed October 14, 2023

Although tools like the Climate and Economic Justice Screening Tool (CJEST) and EJScreen provide valuable data and insights, on-the-ground knowledge, expertise, and additional data sources specific to Puerto Rico are essential to fully understand the energy justice landscape in the region.

3.5.4 Energy Justice Initiatives

The advancement of energy justice by and for Puerto Ricans is well underway as evidenced by multiple examples, just a few of which we highlight here. For example, Queremos Sol, a coalition of community leaders in Puerto Rico, advocates for distributed solar and storage and conducts associated modeling and analysis (Biaggi, Kunkel, and Rivera 2021). And community-based resilient energy projects have been developed across Puerto Rico, including Casa Pueblo's Adjuntas Pueblo Solar[52] initiative and Hydroelectric Cooperative of the Mountains' community microgrid in Castañer (IREC 2022). Other examples include:

- Resilient Power Puerto Rico[53] projects and other initiatives
- Institute for a Competitive and Sustainable Economy and Rocky Mountain Institute, *Public Collaborative for Puerto Rico's Energy Future* (RMI and ICSE 2018)
- Rockefeller Foundation, Fundación Comunitaria de Puerto Rico, and Rocky Mountain Institute, Community Energy Resilience Initiative[54]

[52] "Adjuntas Pueblo Solar," Casa Pueblo, https://casapueblo.org/la-increible-hazana-de-casa-pueblo/.
[53] https://resilientpowerpr.org/.
[54] "Resiliencia Comunitaria In Puerto Rico," Rocky Mountain Institute, https://rmi.org/community-energy-resilience-initiative/.

- Foundation for Puerto Rico Whole Community Resilience Planning Program,[55] including Interactive Social Capital and Vulnerability and Risk Maps
- Enterprise Community Partners et al. *Communities Together: A Guide For Resilient Community Center Design In Island Communities* (resilientSEE Puerto Rico 2019)
- CDBG-DR and the Puerto Rico Department of Housing, Community Energy and Water Resilience Installations Program[56]
- Solar workforce development initiatives including Interstate Renewable Energy Council's Puerto Rican Solar Business Accelerator,[57] *Puerto Rico Solar Industry Workforce Market Study* (IREC 2021) and case study of gender equity in solar workforce development (IREC n.d.)
- Inter-American University of Puerto Rico-Metro Campus is launching a new technical center for environmental justice in partnership with Energy Justice for Puerto Rico and the Department of Economic Development and Commerce, with support from EPA[58]
- Development of Puerto Rico Social Vulnerability Index to, "capture vulnerability across minority ethnic and racial subgroups in Puerto Rico, where 98.8% identify as Hispanic or Latino" (Tormos-Aponte, García-López, and Painter 2021).

3.6 Energy Justice and the Circular Economy

As jurisdictions around the world make progress toward ambitious renewable energy and decarbonization goals, two important considerations are the sustainability of supply chains of technologies that will power energy transitions, including access to critical materials[59] and how to keep those materials in productive use and out of landfills at the end of a product's useful life (end of life, or EOL). The circular economy is an approach to resource management based on the principles of eliminating waste and pollution, circulating resources at their highest value, and regenerating nature to create safe jobs and healthy resilient communities while reducing greenhouse gas emissions and biodiversity loss.[60] A circular economy for energy materials (Figure 24) entails redesigning technologies to reduce material use; finding substitutions for critical materials; designing for extended product lifetime and recyclability; developing remanufacturing and recycling processes and markets for materials; and developing market and policy mechanisms to compel reuse, remanufacturing, and recycling. Advancing the circular

[55] "Whole Community Resilience Planning Program," Foundation for Puerto Rico, https://foundationforpuertorico.org/en/wcrp/.
[56] "Community Energy and Water Resilience Installations Program," CDBG-DR, https://cdbg-dr.pr.gov/en/community-energy-and-water-resilience-installations-program/.
[57] " Puerto Rican Solar Business Accelerator," IREC, https://irecusa.org/programs/puerto-rican-solar-business-accelerator/.
[58] "EPA Joins Environmental and Community Leaders to Help Design Inter-American University's Role as New Technical Center for Environmental Justice in PR and USVI," EPA, https://www.epa.gov/newsreleases/epa-joins-environmental-and-community-leaders-help-design-inter-american-universitys.
[59] Critical materials are defined by the U.S. Secretary of the Interior as any non-fuel mineral, element, substance, or material that has a high risk of supply chain disruption and serves an essential function in one or more energy technologies, including technologies that produce, transmit, store, and conserve energy. Highly critical materials in the near and medium term are cobalt, graphite, lithium, and nickel, magnesium, and various rare earths (dysprosium, gallium, iridium, neodymium, and terbium): "What Are Critical Materials and Critical Minerals?" EPA, https://www.energy.gov/cmm/what-are-critical-materials-and-critical-minerals.
[60] "Circular Economy Introduction: What is a circular economy?" Ellen MacArthur Foundation, https://ellenmacarthurfoundation.org/topics/circular-economy-introduction/overview.
"What is a Circular Economy? EPA, https://www.epa.gov/circulareconomy/what-circular-economy.

economy for energy materials is also one of NREL's critical objectives to ensure essential supply chain materials are available in the necessary quantities and at their highest value to support the renewable energy transition.[61]

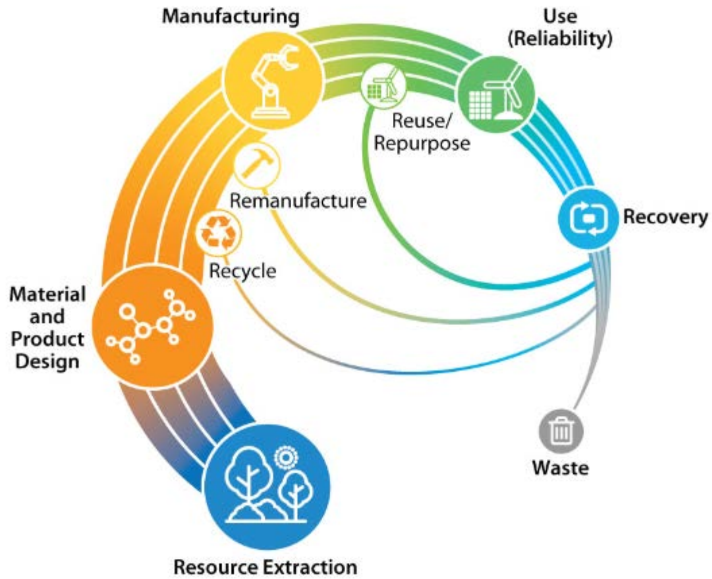

Figure 24. Circular economy for energy materials

Source: Circular Economy for Energy Materials," NREL, https://www.nrel.gov/research/circular-economy.html.

The circular economy for energy materials in Puerto Rico and elsewhere has implications for distributive justice (equitable distribution of energy system benefits and burdens, including exposure to risk, across all members of society) and restorative justice (efforts to repair harms to communities and the environment caused by energy activities and prevent future harm). The energy system of the future, while reducing lifecycle emissions, must also eliminate harm to people and the environment during extraction and processing of raw materials, keep materials in productive use at EOL, and use them as raw materials in the next generation of equipment. Developing a circular economy for energy materials in Puerto Rico is a pathway to ensuring renewable energy equipment like solar panels and lithium-ion batteries does not burden Puerto Rico's overtaxed solid waste infrastructure or create pollution, and instead contributes to economic and workforce development in the form of jobs in processing, transporting, remanufacturing, reuse, and recycling industries for these materials. Throughout PR100, we received multiple questions and comments from members of the Steering Committee, from the Advisory Group, and during community engagement events expressing concern about what will happen with solar panels and batteries at EOL. This section provides a high-level overview of this topic.

[61] "Circular Economy for Energy Materials," NREL, https://www.nrel.gov/research/circular-economy.html.

3.6.1 Technologies and Materials

The results of PR100 indicate deployments of solar photovoltaics, battery energy storage systems, wind power technologies, and electric vehicles (EVs) are all likely to accelerate considerably as Puerto Rico progresses toward its goal of 100% renewable energy by 2050.

Solar panels typically have a service life of 30–35 years,[62] residential batteries' service life can range from 5–15 years,[63] and the service life of EV batteries is 8–10 years.[64] Also, EV batteries can be refurbished for stationary storage by replacing damaged cells or modules and reconfiguring the modules or packs to accommodate a non-vehicle application (Chen et al. 2019). While using longer-lifetime PV modules has been found to be a more effective way to reduce waste than recycling (Mirletz et al. 2022), considering the lifespans of many current technologies, it will be important for Puerto Rico to develop and expand industries for reuse, remanufacturing, and recycling this equipment.

Key materials in the production of these technologies are:

- **Solar photovoltaic (PV) Panels:** cadmium, indium, gallium, selenium, silver, tellurium
- **Lithium-Ion Batteries:** cobalt, lithium, nickel, manganese
- **Wind Turbines:** rare earths (neodymium and dysprosium)
- **EV Batteries:** rare earths (neodymium and dysprosium)
- **All Technologies:** Aluminum and copper (Dominish, Teske, and Florin 2019).

While recycling renewable energy technologies is essential for reasons discussed above, barriers exist. Commercial processes for recycling solar PV panels and lithium-ion batteries are available and improving (Chen et al. 2019), and they are emerging for wind turbine blade material (Cooperman, Eberle, and Lantz 2021) and rare earths from EVs and wind turbines.[65] However, in many parts of the world, including the United States, commercial operations are not widespread. If solar panels contain hazardous materials (e.g., lead or cadmium) in high enough quantities, the panels can be considered hazardous waste (EPA 2021b), and even when not treated as hazardous, the cost to recycle may often be higher than the cost to landfill.[66]

Regarding reuse and remanufacturing, online resale marketplaces are sources for managing and exchanging used and surplus renewable energy equipment, and some recyclers refurbish panels for sale in addition to recycling. In fact, the Associated Press reported that refurbished solar

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[62] "End-of-Life Management for Solar Photovoltaics," DOE, https://www.energy.gov/eere/solar/end-life-management-solar-photovoltaics.

[63] Residential battery life is driven by usage cycle; Telsa warranties PowerWalls for 10 years. ("How Long Do Residential Energy Storage Batteries Last?" *pv magazine,* Ryan Kennedy, September 21, 2021, https://pv-magazine-usa.com/2021/09/21/how-long-do-residential-energy-storage-batteries-last/.

[64] "New Study: How Long Do Electric Car Batteries Last?" *Recurrent*, Liz Najman, March 27, 2023, https://www.recurrentauto.com/research/how-long-do-ev-batteries-last

[65] "Green Rare-Earth Recycling Goes Commercial in the US," *News*, Ames National Laboratory, February 25, 2022, https://www.ameslab.gov/news/green-rare-earth-recycling-goes-commercial-in-the-us.
"Mitsubishi Materials to Recycle Rare Metals from Used EVs," *Materials*, Nikkei Asia, February 9, 2023, https://asia.nikkei.com/Business/Materials/Mitsubishi-Materials-to-recycle-rare-metals-from-used-EVs.

[66] "End-of-Life Management for Solar Photovoltaics," DOE, https://www.energy.gov/eere/solar/end-life-management-solar-photovoltaics.

panels from We Recycle Solar have been sold at Mercados Solar in Carolina, Puerto Rico (O'Malley 2023).

3.6.2 Market and Policy Mechanisms

Policy and market mechanisms have the potential to compel reuse and recycling. In the European Union, the Waste Electrical and Electronic Equipment Directive sets the standard for e-waste recycling policy by requiring the separate collection and proper treatment of waste electrical and electronic equipment, which encompasses renewable energy technologies, and the directive sets targets for collection, recovery and recycling.[67] In the United States, there is no federal regulation regarding recycling renewable energy equipment, and only a few states have enacted legislation regarding EOL management (EPA 2021b; Curtis et al. 2021). Though Puerto Rico's Department of Consumer Affairs recently called for the Legislative Assembly to begin developing the framework for a recycling program for solar energy system components in the near term,[68] no policy currently exists.

Voluntary recycling programs exist. For example, the Solar Energy Industries Association (SEIA)'s National PV Recycling Program[69] is a network of solar recycling and refurbishment companies that can provide a range of EOL solutions for installers and system owners. SolarRecycling.org[70] is another organization that offers donation, resale, or recycling at EOL. Some solar and storage companies like First Solar[71] offer high-value recycling programs to customers for their equipment at EOL. And increasingly, large independent power producers like Greenbacker Renewable Energy Company LLC and national installers like Sunrun are signing long-term contracts with recyclers like SOLARCYCLE[72] to provide EOL services at decommissioning.

3.6.3 Puerto Rico Context and Considerations

As an archipelago, Puerto Rico already grapples with solid waste and sustainable materials management.[73] Puerto Ricans generate more waste per person per day (5.56 pounds) than the U.S. national average (4.91 pounds), and the percentage of recyclables diverted from landfills is less than 10%,[74] compared with 32% on average in the 50 states.[75] Lack of funding, limited recycling infrastructure, and disaster debris further compounds the problem. As of 2020, 18 of the 29 open dumps and landfills in Puerto Rico are "considered to be operating open dumps

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[67] "Waste from Electrical and Electronic Equipment (WEEE)," European Commission, https://environment.ec.europa.eu/topics/waste-and-recycling/waste-electrical-and-electronic-equipment-weee_en.
[68] "Hearing: Island Lacks Rules for Disposal of Solar Panels AND Batteries," The San Juan Daily Star, https://www.sanjuandailystar.com/post/hearing-island-lacks-rules-for-disposal-of-solar-panels-batteries.
[69] "SEIA National PV Recycling Program," SEIA, https://www.seia.org/initiatives/seia-national-pv-recycling-program.
[70] https://www.solarrecycle.org/
[71] "Solutions: Recycling," First Solar, https://www.firstsolar.com/en/Solutions/Recycling.
[72] https://www.solarcycle.us/
[73] "Clean-Up Begins in Puerto Rico, Where Landfills Are Already Filled to Capacity," by Emanuella Grinberg, Polo Sandoval, and Linh Tran, October 23, 2017, CNN, https://www.cnn.com/2017/10/23/health/puerto-rico-cleanup-landfills-maria/index.html.
[74] *Municipalities Mitigating for Future Disasters TODAY*, EPA n.d. https://www.epa.gov/system/files/documents/2021-09/gfx-solid-waste-management-in-puerto-rico.pdf.
[75] "National Overview: Facts and Figures on Materials, Wastes and Recycling," EPA, https://www.epa.gov/facts-and-figures-about-materials-waste-and-recycling/national-overview-facts-and-figures-materials.

(waste is in direct contact with soil and other natural resources)," and "12 operate under closure or compliance orders issued by the federal government" (EPA 2021a). In this context, it will be even more important for Puerto Rico to establish effective systems for reusing and recycling of renewable energy equipment. This may entail (1) developing material recovery facilities and reverse logistics for collecting, storing, sorting, and transporting equipment to recycling facilities outside Puerto Rico or (2) establishing recycling facilities where raw materials are reprocessed into new renewable energy parts or equipment in Puerto Rico.

While solar and storage systems installed in Puerto Rico are ideally hardened to withstand hurricanes (Elsworth and Van Geet 2020), and steps are taken to prepare systems against storms (NREL 2022a), a consideration for Puerto Rico may be shorter-than-average lifespans for some solar equipment in particular due to damage from more frequent and higher intensity storms in the future. Installing more solar kits or refurbished equipment may also result in more equipment reaching EOL sooner than average expected lifespans and increasing the projected volume of EOL equipment in Puerto Rico. For comparison, by 2030, the United States is expected to have as many as 1 million total tons of solar panel waste, and by 2050, the amount is estimated to increase to 10 million total tons (EPA 2021a).

Additional research is needed to further assess:

- The current state of Puerto Rico's solid waste and recycling industry
- Projections for composition, volume, and timing of renewable energy technology reaching the end of its useful life and entering the second life stream (as opposed to the waste stream)
- What is needed to integrate the reuse, remanufacturing, and recycling of renewable energy equipment into the current system or develop new systems
- What opportunities exist to develop or expand reuse, remanufacturing, and recycling industries and associated workforce development in Puerto Rico in the future
- The creation of a small business market around the circular economy for energy materials in Puerto Rico.

4 Renewable Resources

Jaemo Yang[1], Travis Williams[1], Haiku Sky[1], and Manajit Sengupta[1]

[1] National Renewable Energy Laboratory

Section Summary

We assessed renewable energy resources across Puerto Rico in PR100 to determine technical potential, economic potential, and market adoption for multiple renewable energy technologies. We developed high-resolution, multiyear wind and solar data sets to support detailed analysis of both technologies. Land use considerations were incorporated within the utility-scale solar and wind technical potential analysis. The multiple renewable energy technologies included in the assessment comprise two categories:

- **Mature technologies:** distributed solar, utility-scale solar, utility-scale wind (offshore and land-based), and hydropower (refurbishment of existing systems and expansion of non-powered dams)
- **Emerging technologies:** marine energy and ocean thermal, pumped storage hydropower, and floating solar.

Key Findings

- Renewable energy potential assessed for Puerto Rico exceeds the current and projected total annual loads by more than tenfold through 2050.
- The technical potential of mature technologies—utility-scale solar, distributed solar, and land-based wind—is sufficient to achieve Puerto Rico's renewable energy goals.
- Emerging technologies may further diversify the technology mix in the future.
- Utility-scale solar PV potential capacity on nonagricultural land is sufficient to meet total annual electric load to 2050 in our scenarios.
- More utility-scale solar PV developable capacity per site is available at a lower levelized cost of electricity (LCOE) on average in scenarios where more land is available.

Considerations

- While technical potential of mature technologies is sufficient to achieve Puerto Rico's renewable energy goals, community participation and evaluation of land use priorities is important when making decisions about siting solar and wind projects.
- Divergent stakeholder visions for Puerto Rico's energy future will need to be reconciled in the process of charting a pathway to implementation of Puerto Rico's energy future. Competing interpretations of existing policy such as land use regulations will need to be addressed.

A key area of any renewable energy analysis is a quality assessment of the available resources. In particular, renewable resources are typically location-specific and can vary widely. Additionally, renewable resources (particularly solar, wind, and hydropower) vary subhourly, daily, seasonally, as well as interannually. The site-specific nature and time-dependent profile of potential generation is critical to assessing the value of these resources as well as how they can work together in an integrated bulk power system.

We conducted assessments of the technical potential of a variety of renewable energy resources in Puerto Rico, and we have generated high-resolution, multiyear resource data sets comprising land-based wind, offshore wind, and solar, as well as wind and solar forecast data. Additional resource potential assessments were conducted for technologies including marine energy and ocean thermal, refurbishment of existing hydropower, pumped storage hydropower, and floating photovoltaics (FPV).

The resource data are used to determine the renewable energy technical potential of a given technology to define its achievable energy generation given system performance, topographic, environmental, and land use constraints. The types of resource potential include technical potential, economic potential, and market adoption (Figure 25, page 60). Technical potential is the total amount of a resource that could be deployed; it is only limited by physical constraints (e.g., rooftop area, available land area, and technical efficiency). Economic potential is a subset of technical potential and includes resources that incorporate costs and would result in potential project locations with a positive economic value. Market adoption then typically incorporates competition (either currently or in the future) to determine which resource to deploy.

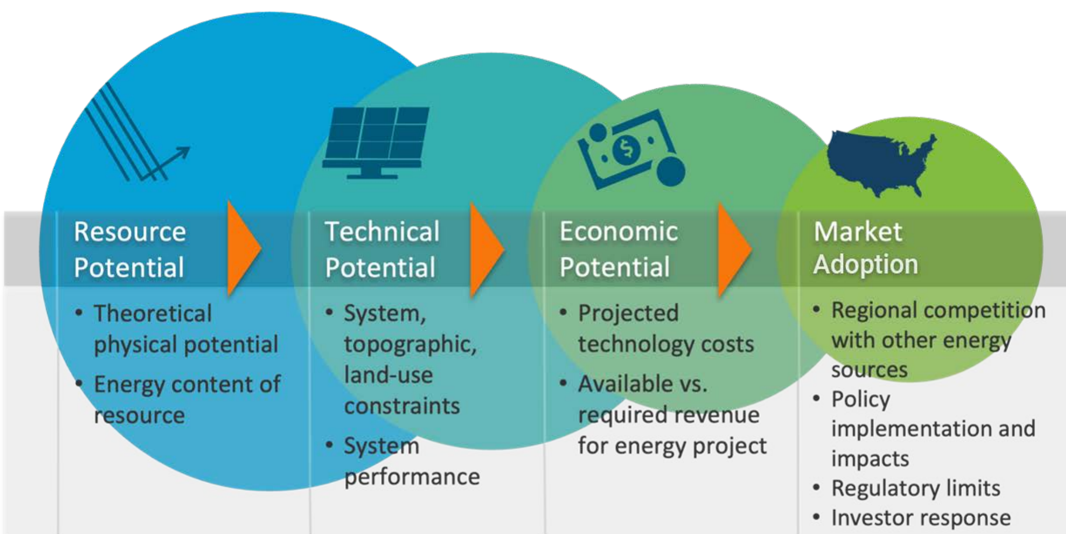

Figure 25. Levels of renewable energy potential analysis, starting with the theoretical potential provided by a region's atmospheric resource and progressively refining this estimate with technical, economic, and market considerations

Source: Brown et al. (2016)

Technical potential is a physical limit but does not indicate likely deployment. The benefit of assessing technical potential is that it establishes an upper boundary estimate of development potential (Lopez et al. 2012). A summary of the potential capacity and potential annual generation in Puerto Rico, based on technology type, is presented in Table 6.

Table 6. Technical Potential in Puerto Rico of Technologies Considered

Resource Name	**Potential Capacity**	**Potential Annual Generation**	**Notes**
Biofuel engines	No Limit	—	Assumes limitless imports of biofuels
Existing hydropower	100 MW	0.2 TWh/year	Assumes rebuilding and expanding existing resources. See Section 4.3, page 111.
Ocean thermal energy conversion	4,400 MW (estimated across Puerto Rico and U.S. Virgin Islands)	38.0 TWh/year (estimated across Puerto Rico and U.S. Virgin Islands)	PR100 considered only the shelf off the coast of the Municipality of Yabucoa and estimated 4,000 MWe of nominal ocean thermal energy conversion capacity, which we modeled conservatively to produce a maximum of 4,400 MWe (NREL-estimated maximum production figures are closer to 5,200 MWe). Technical potential estimates are from Kilcher, Fogarty, and Lawson (2021); the nominal versus maximum production value is from Ascari et al. (2012). See Section 4.4, page 114.
Offshore wind	46,850 MW	156.0 TWh/year	Duffy et al. 2022
Rooftop solar photovoltaics (PV)	20,400 MW	24.6 TWh/year	Mooney and Waechter 2020
Utility-scale PV (excludes agricultural land)	14,220 MW	24.1 TWh/year	Based on Less Available Land scenario variation, which excludes agricultural land
Utility-scale PV (includes agricultural land)	44,660 MW	75.5 TWh/year	Based on More Available Land scenario variation, which includes agricultural land
Utility-scale land-based wind (excludes agricultural land)	1,610 MW	5.9 TWh/year	Based on Less Available Land scenario variation, which excludes agricultural land (Duffy et al. 2022)
Utility-scale land-based wind (includes agricultural land)	4,600 MW	16.9 TWh/year	Based on More Available Land scenario variation, which includes agricultural land (Duffy et al. 2022)
Total Annual Generation Potential (without biofuel engines)		**248.8 TWh/year (excluding agricultural land)**	Compared to a current annual load of 18.9 TWh in 2021
		313.9 TWh/year (including agricultural land)	

One of the first questions a jurisdiction must ask when it considers meeting 100% of its electricity needs with renewable energy is whether resources are sufficient to accomplish the goal. In some parts of the world, transitioning to 100% renewable energy would be very expensive due to insufficient resources (e.g., low solar irradiance or low wind). As depicted in

Figure 26, comparing the potential annual generation (from Table 6) to the 2021 annual load confirms that the combination of renewable resources in Puerto Rico is more than sufficient to meet the electrical energy demands of the archipelago on an annual basis. The 2021 annual load data were selected as it represents the highest level of load across the span of the study, given that loads are projected to decrease through 2050 (see Section 5.1, page 119).

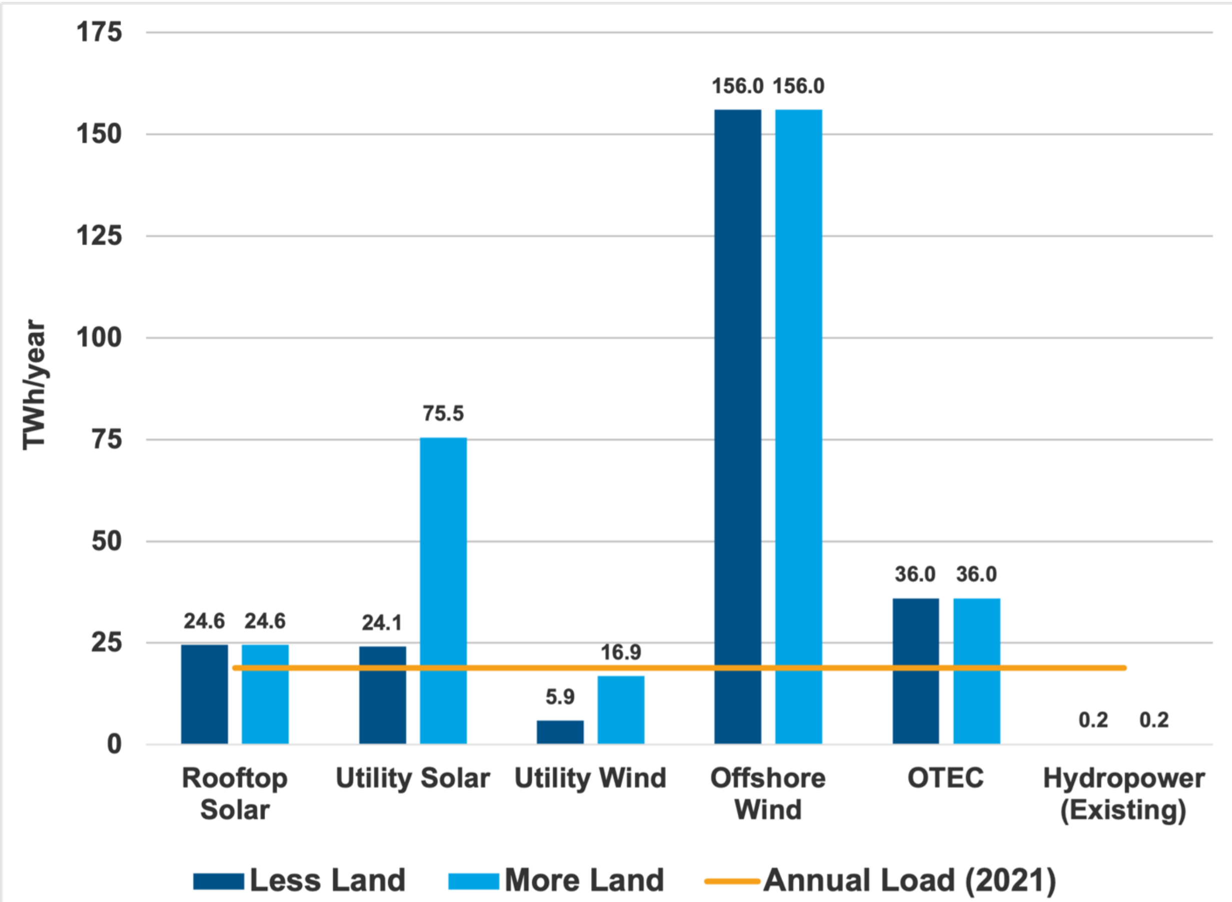

Figure 26. Potential annual generation in TWh of various renewable technologies compared to annual load in Puerto Rico in 2021

4.1 Solar

4.1.1 Solar Resource Assessment

High-resolution data sets for Puerto Rico are available in the National Solar Radiation Database (NSRDB) (Sengupta et al. 2018). The NSRDB is a publicly accessible data set that has been developed and disseminated by NREL for more than 20 years. The NSRDB provides meteorological data for North and South America, as well as estimations of solar radiation based on satellite data for solar energy-related applications. In a previous project, NREL additionally developed an approach to downscale solar resource data from the NSRDB from a 4-km x 4-km spatial and 30-minute temporal resolution to a 2-km x 2-km and 5-minute resolution (Buster et al. 2021), and Grue et al. (2022) used the 2-km and 5-min data for quantifying the solar energy resource for Puerto Rico.

The satellite-derived data sets used in this work were produced using the Physical Solar Model (PSM), which was developed as part of a collaboration of NREL, the University of Wisconsin, and the National Oceanic and Atmospheric Administration to generate high-quality solar resource data. The PSM is a two-step physical model that includes (1) retrievals of cloud and aerosol properties from satellites and data acquisition of other meteorological properties and (2) implementation of a radiative transfer model with the integrated meteorological inputs to produce the final data set.

The PSM adopts REST2 (Gueymard 2008), which is known to be one of the best clear-sky radiative transfer models (Badescu et al. 2012) to calculate clear-sky global horizontal irradiance (GHI) and direct normal irradiance (DNI). For cloudy-sky conditions, the Fast All-sky Radiation Model for Solar applications (FARMS) (Xie, Sengupta, and Dudhia 2016), which can efficiently simulate all-sky solar radiation, is used to calculate GHI, and then the Direct Insolation Simulation Code (Maxwell 1987) model is used to calculate DNI.

The NSRDB has notably evolved since the initial publication of the database in 1992. The most recent version of NSRDB includes these updates:

- Estimation of high-resolution solar resource data based on the state-of-the-art in the satellite information
- Implementation of machine-learning technique to fill missing cloud properties
- Improved projection of clouds using parallax and shading corrections
- Improved projection of surface albedo.

The PSM requires various input sources to generate high-quality solar radiation time-series variables. The cloud properties were retrieved from the Geostationary Operational Environmental Satellite, or GOES (Menzel and Purdom 1994; Schmit et al. 2005). The aerosol optical depth was obtained from NASA's Moderate Resolution Imaging Spectroradiometer (MODIS) (Chu et al. 2002) and Modern Era Retrospective analysis for Research and Applications, version 2 (MERRA-2) (Gelaro et al. 2017). PSM uses surface albedo data derived from MODIS, which provides high-quality measurements at 30 arc-seconds for each 8-day interval. The other atmospheric data inputs (e.g., wind speed and direction, pressure, temperature, and water vapor) for the radiative transfer model were provided by NASA's

MERRA-2. Comprehensive details about the input data of NSRDB are summarized by Sengupta et al. (2018).

We calculated the long-term average of GHI and DNI over 25 years (1998–2022) in spatial, seasonal, and annual scales to analyze how the solar energy resources behave across Puerto Rico. Figure 27 maps the 25-yr average of GHI and DNI for Puerto Rico. The average estimates are based on the daily total of GHI and DNI obtained from the 4-km and 30-min NSRDB data sets (the most recent version of NSRDB generated by the PSM Version 3.2.2). As shown in Figure 27, the mean solar irradiances depend on land cover and topography. GHI and DNI are high on the northern and southern coast of the main island, whereas mountain areas exhibit low GHI and DNI.

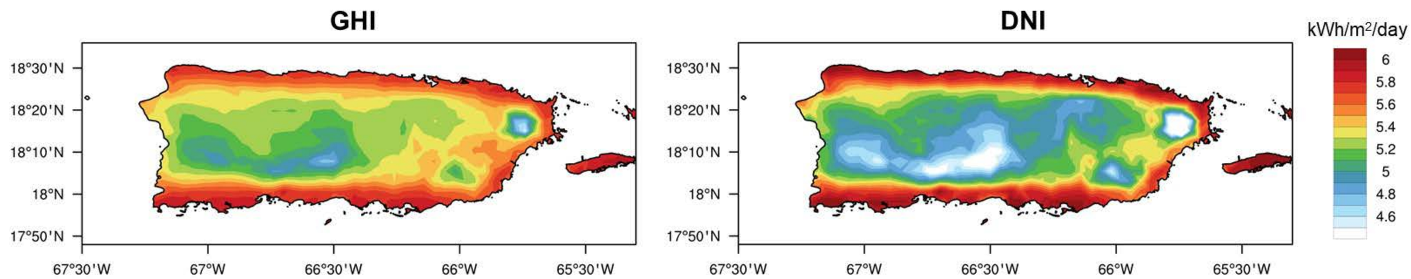

Figure 27. 2D maps of 25-yr average GHI and DNI for Puerto Rico

4-km and 30-min resolution NSRDB data sets

Figure 28 shows the monthly variation of GHI and DNI from 1998 through 2022. The monthly average GHI and DNI ranged from 4.49 to 6.56 kWh/m2/day and from 5.17 to 6.74 kWh/m2/day across all months over 25 years. Higher GHI values (>6 kWh/m2/day) were observed from March through August than in the other months. Meanwhile, DNI shows a different seasonal pattern than GHI for Puerto Rico. As shown in Figure 28, DNI peaks in the dry season (December–April) and exhibits lower DNI in the early rainy season (May–July) and the late rainy season (August–November) than in the dry season. This is because increased cloudiness prevails in Puerto Rico during the wet season. DNI is essentially more sensitive to cloudiness than GHI; thus, the wet season produces more clouds, which results in lower DNI.

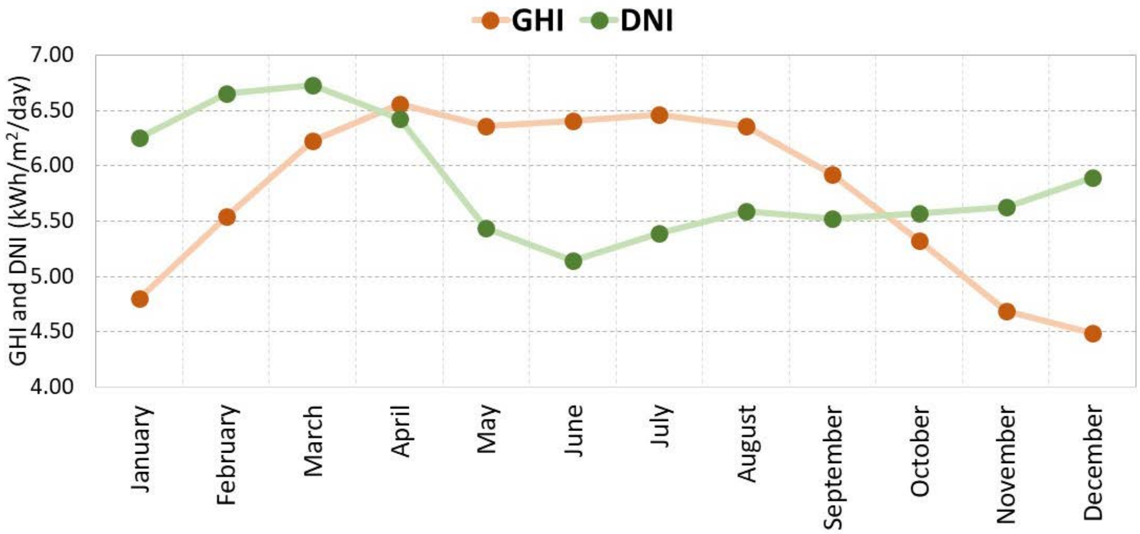

Figure 28. Monthly average GHI and DNI for Puerto Rico

Figure 29 represents the yearly changes in GHI and DNI, similar to monthly variation shown in Figure 28. Over the 25 years, Puerto Rico exhibits GHI and DNI ranging from 5.44 to 5.94 kWh/m^2/day and from 5.15 to 6.24 kWh/m^2/day respectively. The year 2010 shows the lower solar resource (GHI of 5.44 kWh/m^2/day and DNI of 5.15 kWh/m^2/day) than the other years. No obvious strong decreasing or increasing trends were captured from the NSRDB for Puerto Rico.

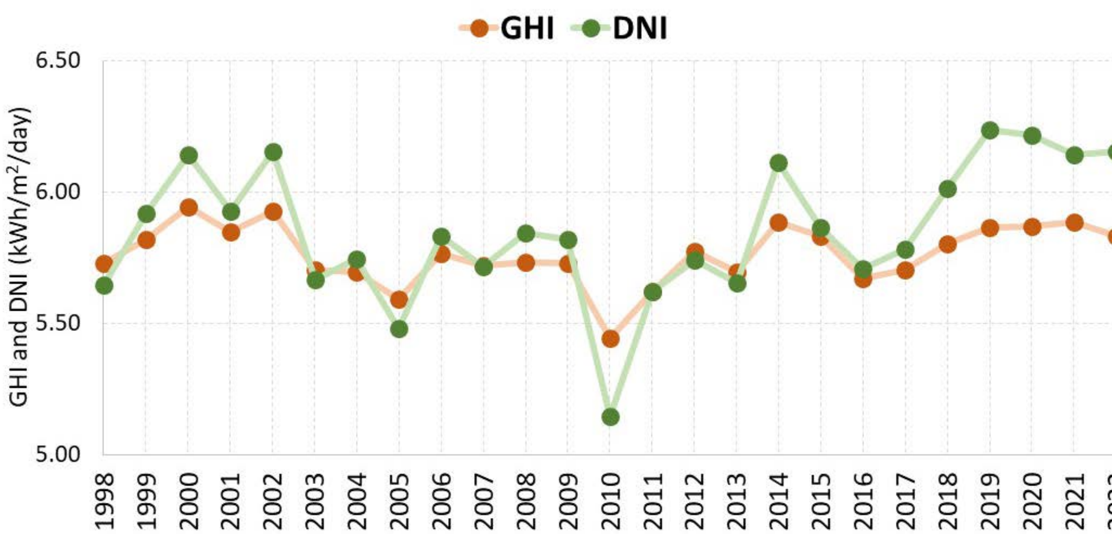

Figure 29. Yearly average GHI and DNI for Puerto Rico

Users can access the solar resource data sets via the NSRDB website in three ways: the NSRDB Viewer, an application programming interface (API), or a cloud-based service. [76]

4.1.2 Rooftop Solar Technical Potential

We used results of an NREL analysis conducted by Mooney and Waechter (2020) to assess (1) how rooftop solar potential in Puerto Rico is distributed geographically, by income group,

[76] See "How to Access the Data," NREL, https://nsrdb.nrel.gov/data-sets/how-to-access-data.

building type, and tenure of the building occupants and (2) how much electrical consumption can be offset by rooftop solar.

The analysis processed 2015–2017 lidar scans (<0.35 nominal resolution) covering 96% of Puerto Rico's building stock. The lidar data were intersected with Census demographics tables of household counts by income, tenure, and building type. Given that the lidar data did not allow direct observation of the tenant's attributes, a bootstrapping method was used. Additionally, a statistical model, trained on lidar tracts, was used to impute building stock characteristics (e.g., area, orientation, shading) for 4% of building stock without sufficient data. Finally, solar generation was simulated for each roof plane using NREL's PVWatts and was aggregated at the tract and county level. Figure 30 showcases a summary of the methodology.

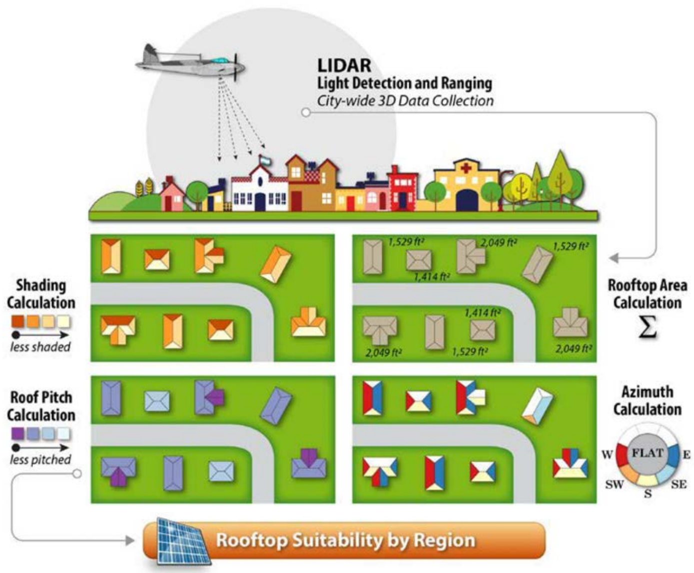

Figure 30. Summary example of rooftop PV analysis methodology

Source: Mooney and Waechter (2020)

4.1.2.1 Assumptions for Building Suitability

The following assumptions were used in the analysis conducted by (Mooney and Waechter 2020) for rooftop suitability (Table 7) and PV system performance (Table 8).

Table 7. Rooftop Suitability Assumptions

Source: Mooney and Waechter (2020)

Roof Physical Characteristics	Description
Shading	Measured shading for four seasons and required an average of 80% unshaded surface
Azimuth	All possible azimuths
Tilt	Average surface tilt <= 60 degrees
Minimum Area	>= 1.62 m^2 (area required for a single solar panel)

Table 8. PV Performance Assumptions

Source: Mooney and Waechter (2020)

PV System Characteristics	Value for Flat Roofs	Value for Tilted Roofs
Tilt	15 degrees	Tilt of plane
Ratio of module area to suitable roof area	0.7	0.98
Azimuth	180 degrees (south-facing)	Midpoint of azimuth class
Module Power Density	183 W/m^2	
Total system losses	Varies (System Advisor Model defaults + individual surface % shading)	
Inverter efficiency	96%	
DC-to-AC ratio	1.2	

4.1.2.2 Residential Rooftop Solar Potential Results

The results of the Mooney and Waechter (2020) analysis indicated the following:

- Potential annual generation for all residential buildings is 24.6 TWh/year.
- Potential annual generation for low- and moderate-income households is 11.9 TWh/year.
- Potential capacity for all residential buildings is 20.4 GW_{DC}.
- Potential capacity for low- and moderate-income households is 9.8 GW_{DC}.

The data produced from the analysis, summarized in Table 9, are a key input to the dGen modeling (see Distributed Photovoltaics and Storage Investments Over Time, Section 9).

Table 9. Residential PV Rooftop Technical Potential by Income Group

Source: Mooney and Waechter (2020)

Income Group	Household (thousands)	Suitable Buildings (thousands)	Suitable Module Area (millions of m^2)	Potential Capacity (GW_{DC})	Potential Annual Generation (TWh/year)
Very Low (0%–30% AMI)	267.8	203.6	21.9	4	4.8
Low (30%–50% AMI)	151.2	129.1	13.5	2.5	3
Moderate (50%–80% AMI)	203.3	177.4	18.6	3.4	4.1
Middle (80%–120% AMI)	297.8	267.7	28.2	5.1	6.2
High (>120% AMI)	317.1	279.5	29.6	5.4	6.5

Income Group	Household (thousands)	Suitable Buildings (thousands)	Suitable Module Area (millions of m^2)	Potential Capacity (GW_{DC})	Potential Annual Generation (TWh/year)
All Low- and Moderate-Income Buildings	622.3	510.1	54	9.8	11.9
All Residential Buildings	1,237.2	1,057.3	111.8	20.4	24.6

While the modeling and analysis primarily focused on residential rooftop sites identified from lidar data, the results data set does not include structures such as carports and other nonrooftop options potentially suitable for PV deployment. PR100 modeling and analysis inclusive of carports and other nonrooftop options was not conducted.

The total capacity of over 20 GW_{DC} of potential rooftop capacity represents an open access/permissive siting regime. In other words, this capacity includes all available rooftop surfaces and planes without notable reductions for shading. If more stringent restrictions were applied, including shading (such as excluding all cells/objects where shading losses exceed 20%), reduced slopes, and excluding a certain range of planes, the technical potential would be reduced significantly. Research examining the impact of these constraints on technical potential is ongoing. Specific adjustments for rooftop capacity in the distributed solar and storage adoption modeling conducted for this study using the Distributed Generation Market Demand (dGen) model are discussed in Section 7.3.4.

4.1.3 Utility-Scale Solar Technical Potential

We performed a technical potential analysis to 1) provide an overview of the resource potential of utility-scale solar photovoltaic (UPV) production in Puerto Rico and 2) to provide the required technical potential inputs for downstream models in PR100. The most direct downstream model using these inputs is Engage, a capacity expansion model that also incorporates a suite of factors including electricity demand modeling, federal and local incentive programs, competition with other generation sources, and other market-oriented factors (see Section 8).

Technical potential refers to the maximum amount of capacity and generation possible in an area, given physical, technological, and regulatory constraints (Lopez et al, 2012). Factors such as topography, water bodies, infrastructure, setbacks from structures, conservation areas, military restrictions, and other siting constraints restrict the amount of capacity that can be installed in a study area. Factors such as generator and land use efficiency combine with capacity estimates to set the maximum amount of energy generation possible in an area. Capital, operating, and financing costs combine with these factors to further refine the potential production possible for a study area by filtering out potential generation sites that cannot operate under some maximum cost threshold. Each level of energy production potential analysis serves as the basis for finer-scale analyses. Ultimately, market conditions and government policies will refine these technical and economic potential assessments to arrive at some, typically much smaller, estimate for deployable market adoption (Figure 25).

This analysis employs a technical potential modeling methodology centered on the Renewable Energy Potential (reV) model, which enables an exploration of a range of uncertainty in both future land use and future technology advancement scenarios. A description of this modeling process, the specific methodology for developing a techno-economic potential analysis for Puerto Rico, and the results of that analysis are presented below. This analysis uses the updated NSRDB described above in Section 4.1.1 as the input resource potential. It also uses cost and performance parameters that align with the Annual Technology Baseline for model years 2030, 2035, 2040, 2045, and 2050. This work builds on and updates a previous technical potential analysis for Puerto Rico conducted by Grue et al. (2021).

4.1.3.1 Methodology

The methodological components of this project include (1) estimating of the technical potential for utility-scale solar capacity in Puerto Rico, (2) incorporating an updated version of the NSRDB (Sengupta et al. 2018) into potential generation estimates, and (3) estimating general costs in the form of a levelized cost of energy for all potential sites across Puerto Rico.

Each of these components are performed using a modeling pipeline centered on the reV model[77] (Maclaurin et al. 2019). reV is a modeling platform that: converts atmospheric resource data into energy capacity and generation, combines this with financial assumptions to generate levelized cost of electricity (LCOE), constrains these outputs with detailed land use data, and connects the resulting simulated plants to the electric grid. To convert NSRDB irradiance data to energy, reV uses the PVWatts module of the System Advisor Model (SAM) (Blair et al. 2018). For this work, we used reV version 0.7.3, NSRDB version 3.2.2, and PVWatts version 8. The data for the NSRDB and the source code for reV and SAM are all open-sourced and available to the public.

To address uncertainty in available land for development, we modeled two land use variations: a More Land variation with minimal restrictions on access to land and a Less Land variation with a high level of restrictions. To address the uncertainty associated with the technological and economic development of utility-scale solar technology, we modeled three future technology scenarios: a Conservative Technology scenario with minimal performance and cost improvements over time, an Advanced Technology scenario with large improvements, and a Moderate Technology scenario with projections between the first two. These scenarios directly correspond with the cost and system performance trajectories described in the 2022 Annual Technology Baseline ATB (NREL 2022). The Annual Technology Baseline (ATB)[78] is an NREL product that models representative system parameters, performance, and costs for a suite of renewable energy technologies and projects them out to 2050 for different resource classes and technology advancement scenarios.

We model LCOEs to reflect costs and financing structures using standard assumptions described in the ATB and those that incorporate local market conditions in Puerto Rico to align with the cost modeling performed in Section 8 (page 209). Modeling LCOEs using standard assumptions isolates the effect of generation in Puerto Rico and allows for comparisons with other regional

[77] "Geospatial Data Science: reV: The Renewable Energy Potential Model," NREL, https://www.nrel.gov/gis/renewable-energy-potential.html.
[78] "Annual Technology Baseline," NREL, https://atb.nrel.gov/.

studies that also use the ATB. Modeling LCOEs that incorporate island-specific market conditions provides a more realistic view of realizable costs.

Outputs of the reV model include detailed maps of developable area, point data sets representing potential plant models with cost, generation, and land use attributes, and half-hourly time-series of modeled generation at each of these points.

4.1.3.1.1 Technical Potential Modeling

The reV model is designed as a pipeline of processing modules where the outputs of each module serve as inputs into the next. The first module, reV Generation, serves as a spatial coordinator of the SAM PVWatts module, which ingests a time-series of irradiance data and simulates a time-series of generator capacity factors along with an estimate of LCOE. reV passed data from the NSRDB through SAM and built a time-series of these capacity factors and this initial LCOE estimate at all available points in Puerto Rico. Data generated by the reV Generation module are in the same spatial and temporal resolution as in the NSRDB, and results were provided in 24 yearly files each with 1,100 4-km points, and 17,520 30-min time-steps at each point for each run. These data were passed into the reV Multi-Year module, which combined all 24 yearly data sets and calculates long-term mean capacity factors and LCOEs.

The multiyear file was then passed into the reV Supply Curve module, which aggregated values into a separate grid sized to represent typical sizes for solar plants, applied a land use inclusion layer (see Section 4.1.3.1.7) to refine the generation and LCOE values, and set the capacity of each resulting model plant according to this same land use grid. The supply curve grid resolution was based on the 10-m land use grid; it was not aligned with the generation grid. Because of the land area requirements for a typical solar plant in Puerto Rico, the supply curve grid was smaller than the resource grid cell so each supply curve grid could overlap with up to four generation grids. To calculate capacity, the area of the inclusion layer within each cell was multiplied by a capacity density value; capacity density is the amount of capacity per unit area for a representative utility-scale PV plant and is described in detail in Section 4.1.3.1.8. Average LCOEs and capacity factors within each supply curve area used the 10-m inclusion layer to weight the value of each contributing generation cell according to the following equation:

$$X_w = \frac{\sum_{i=1}^{n} N_i X_i}{\sum_{i=1}^{n} N_i}$$

where X_w is the weighted value of a variable X, n is the number of reV Generation cells intersecting the target reV supply curve cell, and N is the number of 10-m inclusion layer cells within the intersection of a reV Generation cell and the target reV supply curve cell. A visualization of the process is available in Figure 31.

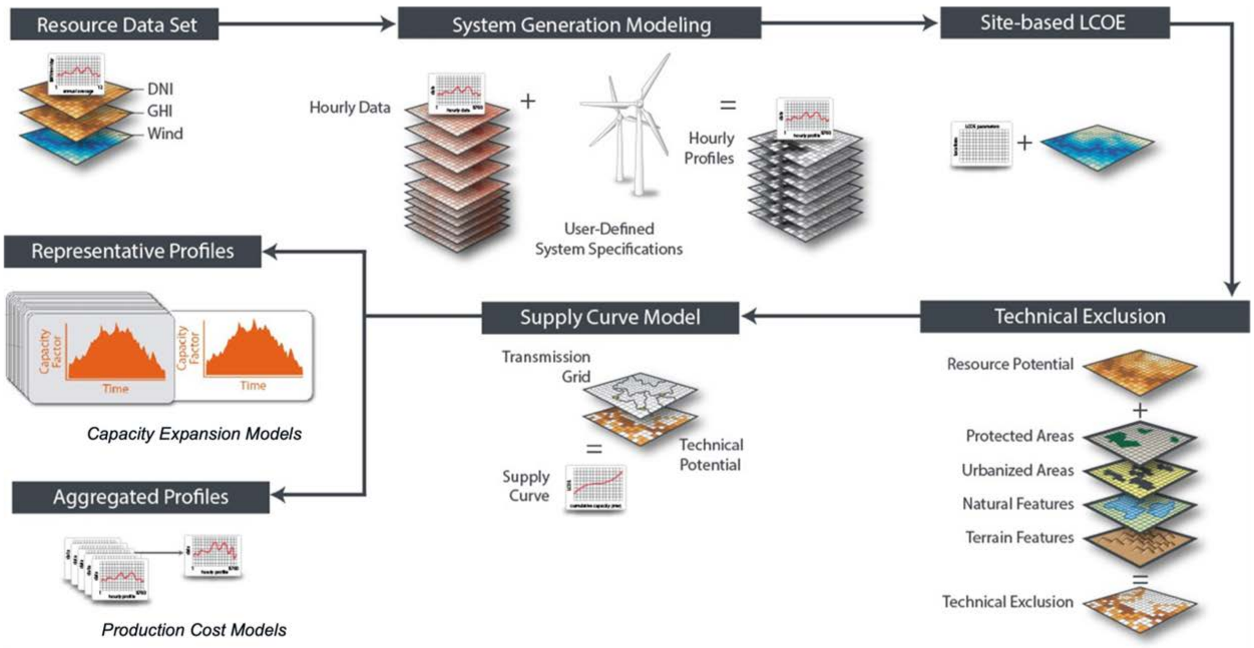

Figure 31. Diagram of reV modeling pipeline

Source: https://github.com/NREL/reV

This second grid was set to a 2.88-km by 2.88-km area, which is the standard grid cell size used for reV UPV modeling for the contiguous United States (CONUS). Because this area was larger than the bounding box around any existing plant in Puerto Rico, it might have been appropriate to use a smaller grid cell for increased granularity; however, we maintained this grid size to avoid computational issues in downstream models in the broader PR100 effort.

After capacities, capacity factors, and LCOEs were assigned, each plant was connected to a GIS data set representing the existing transmission grid. This step was performed by measuring the required distance for a tie-line from each model plant to the nearest substation and applying a cost per megawatt-mile value. The resulting cost was then used to calculate a levelized cost of transmission value, which was then added to the site LCOE value to create a total LCOE figure for the project. The output of this step resulted in a supply curve for each model scenario. The supply curve took the form of a georeferenced table of costs and supply variables at each site. Associating available capacity with levelized costs incorporates every component of the technical potential analysis into an easily interpretable data set that can be used to identify relationships between capacity, generation, and cost values but also allows for the identification of spatial relationships between these variables.

The final step of the modeling pipeline was to create a single generation time-series for each model plant resulting from the process described above. This step was performed in reV's Representative Profiles module, which was used to aggregate each contributing generation profile for a given plant by taking a spatially weighted average of all values across the time axis. The resulting data set can provide either the spatially weighted average of each contributing generation profile at each time-step or the individual generation profile that best fits this average profile in terms of an error metric such root mean squared error. The aggregated mean profile will better represent the solar resource across the entire area of a plant with less variation while the latter will best represent the generation profile of a single location within the plant. Because reV models the production of an entire plant, the former was used in this case.

The final resulting data set included 17,520 time-steps per year for each site, 23 resource years, six system cost/performance years, three technology advancement scenarios, and two land use variations. Each data set included plant capacity, capacity factors, annual generation, tie-line costs and distances, LCOEs, and GHI.

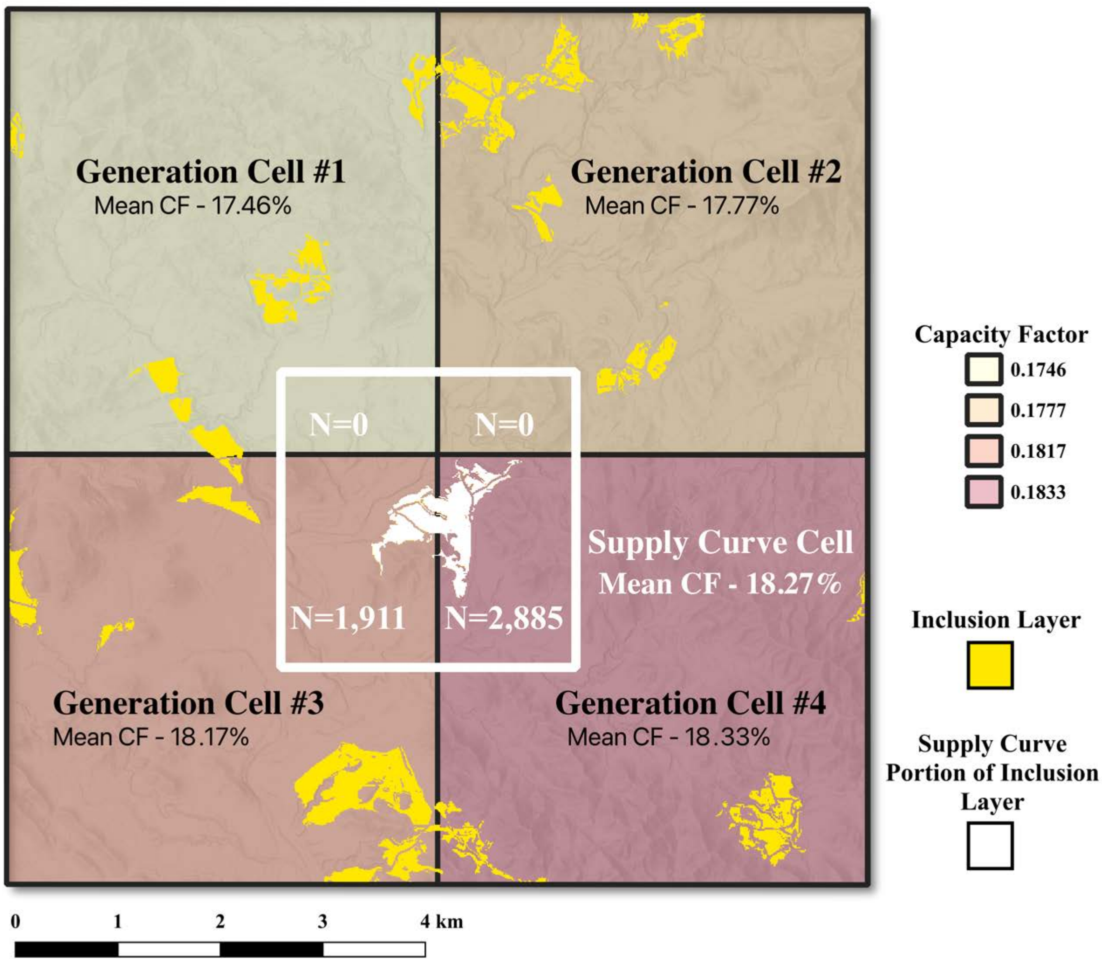

Figure 32. Visualization of the aggregation process for reV Generation capacity factors within a supply curve cell

The value from each contributing generation cell was weighted by the number (N) of inclusion layer cells it contained when the average value was calculated. CF is capacity factor.

4.1.3.1.2 Cost Modeling

The question of cost in Puerto Rico is complex. Because of consistent local cost differences and supply chain issues like those at the time of the analysis, capital costs for energy projects in Puerto Rico were significantly higher than they were in the 50 U.S. states. Local factors that lead to elevated costs include transportation of component parts and materials, persistent industry-wide supply chain issues from the COVID-19 pandemic, inflation, and international conflict.

Additionally, regulatory differences in Puerto Rico from the 50 U.S. states can affect the ultimate cost of an energy project. Uncertainty about the longevity of these cost-increasing factors is significant; industry-wide supply chain issues may or may not resolve, the magnitude of local cost factors could easily change, and the additional cost burden of the current regulatory structure may or may not persist. However, efforts have been made to quantify the trajectory of these costs given what we know about the system today. Using cost and financing assumptions derived from public power purchase and operating agreements (PPOAs) in Puerto Rico, the capacity expansion modeling team developed a process for calculating LCOEs under ATB technology future scenarios (see Section 8, page 209). This process takes the costs associated with the ATB cost year 2023, the financing assumptions described in the PREB report, and the agreed upon LCOE figures used to set the PPOA prices and develops a model that solves for these empirical LCOE figures and provides location factors (cost multipliers) for Puerto Rico in relation to CONUS, from which the standard assumptions are derived.

To contextualize the effect of these Puerto Rico–specific cost increases, we compared PPOA-derived LCOEs and LCOEs calculated using the standard ATB assumptions and the simple fixed charge rate (FCR) method (NREL 2022b). To understand the technical potential outputs from reV, it is important to highlight the following differences between the two financial models:

1. The FCR method uses standard ATB assumptions throughout the model while the PPOA uses Puerto Rico–specific assumptions throughout.
2. The PPOA method uses the capital and operation costs of the ATB to derive cost scaling over time.
3. The PPOA method uses diminishing location factors over time to reflect the likely impermanence of current price hikes.
4. The PPOA method includes the investment tax credit whereas the standard model does not.
5. Therefore, the outputs will describe:
    A. High alignment with near-future empirical LCOEs and long-term finance structures (25 years in this case)
    B. An accounting for Puerto Rico–specific costs and incentives
    C. A highly researched cost trajectory over time
    D. An assumption of a general return to status quo pricing over time.

4.1.3.1.3 Simple Fixed Charge Rate (FCR) Model

The FCR method for calculating LCOE is frequently used to estimate generic costs in technical potential studies. We used the FCR method here to provide a baseline estimate that excludes any unique market and regulatory conditions in Puerto Rico. We included this method to (1) isolate the effect of the solar resource and technology performance on costs, (2) facilitate comparisons with other regional studies using standard assumptions, and (3) provide a baseline cost to quantify the effect of the local cost adders embedded in the PPOA model. The LCOEs that reV calculates include both an LCOE component for each model site before interconnection, which is referred to as the site LCOE and an interconnection LCOE component, which is referred to as the levelized cost of transmission, or LCOT. These were summed to calculate the final output, which we refer to as total LCOE:

$$Total\ LCOE\ = \text{Site LCOE} + \text{LCOT}$$

Here, LCOT was defined as:

$$LCOT\ = \frac{Line\ Cost\ \times\ Capacity\ \times\ Distance * FCR}{(CF \times Capacity\ \times\ 8{,}760\ hours)}$$

where *Line Cost* is the transmission tie-line capital cost in units of cost per unit capacity and unit distance and is set at a constant 3,667 \$/MW-km, *Distance* is the distance from the site to the nearest substation in km, *CF* is the average capacity factor of the site, and *Capacity* is the total potential site capacity in megawatts. *FCR* is defined in detail below. The site LCOE method uses capital costs, fixed operating costs, annual generation, and the FCR to calculate the levelized cost of energy (LCOE) for the plant such that:

$$Site\ LCOE\ = \frac{FCR \times CapEx + OpEx}{(CF \times capacity\ \times 8{,}760\ hours)}$$

where *CapEx* is the total capital expenditure of the project in $\$/kW_{DC}$, *OpEx* is the annual operating expenditure of the project in $\$/kW_{DC}$, and *FCR* is defined as the "amount of revenue per dollar of investment required that must be collected annually from customers to pay the carrying charges on that investment"[79] across the lifetime of the plant. The FCR is calculated as a function of the cost recovery factor (*CRF)* and the project finance factor (*PFF)*, such that:

$$FCR = CRF \times PFF$$

CRF is a function of the weighted average cost of capital (*WACC*) and the cost recovery period of the plant (*t*) and is defined as:

$$CRF = WACC \times \frac{1}{(1 - \frac{1}{(1 + WACC)^t})}$$

where *WACC i*s a function of the debt fraction of capital cost *z,* rate of return on equity (*RROE)*, the average inflation rate over the lifetime of the plant (*i*), the interest rate on debt (*IR*), and the total state and federal tax rate (*TR*) and is defined as:

$$WACC = \frac{1 + [1 - DF] \times [(1 + RROE)(1 + i) - 1] + DF \times [(1 + IR)(1 + i) - 1] \times [1 - TR]}{1 + i} - 1$$

[79] "Annual Technology Baseline: Equations and Variables in the ATB," NREL, https://atb.nrel.gov/electricity/2023/equations_&_variables.

The *PFF* is a function of TR, the present value of depreciation (PVD) and is defined as:

$$PFF = \frac{(1 - TR \times PVD)}{(1 - TR)}$$

where *PVD* is a function of the modified accelerated cost recovery system (MACRS), and the schedule of depreciation factors over the first 6 years of the plant's lifetime (*DS*):

$$PVD = \sum_{y=0}^{y=6} MACRS_y \times DS_y$$

All variables that were used to calculate the FCR are described in Table 10.

Table 10. Variables Used in the Calculation of the FCR

Parameter	Value
Capital cost recovery period (CRP)	25
Debt fraction (DF)	0.735
Depreciation factor schedule (DS)	0.9592, 0.9201, 0.8826, 0.8466, 0.8121, 0.779
Fixed charge rate (FCR)	0.0515
Inflation rate, real (i)	0.025
Interest rate, real (IR)	0.015
Modified accelerated cost recovery system (MACRS)	0.20, 0.32, 0.192, 0.1152, 0.1152, 0.0576
Rate of return on equity, real (RROE)	0.052
Tax rate, state and federal (TR)	0.257

Because the 2022 ATB (NREL 2022b) reports only utility-scale solar costs for single-axis tracking systems, the fixed-tilt costs had to be derived using the 2021 solar benchmarking study (Ramasamy et al. 2022) from which the values of the ATB were drawn. The 2021 fixed-tilt costs, reported in AC, were converted to DC using the DC/AC ratio assumption of 1.28 to gather 2021 fixed-tilt costs at 100 MW (the assumed plant size in the ATB). Then, cost multipliers from this baseline were calculated over time using the reported tracking system costs in the ATB. Costs were then inflated from the reported 2020 dollars to 2021 dollars to standardize values with other models in the PR100 effort. This process replicated the values reported for tracking systems exactly. However, a major drawback of this method is that fixed-tilt system costs were assumed to fall at the same rate as tracking systems.

The 2021 benchmarking study (Ramasamy et al. 2022) also provides capital costs for a range of plant sizes. These costs were used to develop an economies of scale multiplier curve to apply to the costs of each plant after capacities were estimated in the reV exclusion process (see Section 4.1.3.1.5).

Table 11. ATB Costs Associated with Each Technology Scenario and Model Year Assuming a 100-MW_{DC} Plant

Technology Scenario	Year	Capital Cost ($/$kW_{DC}$)	Fixed Annual Operating Cost ($/$kW_{DC}$)
Advanced	2022	809.16	14.02
Advanced	2023	764.54	13.43
Advanced	2030	452.26	9.43
Advanced	2035	424.45	8.98
Advanced	2040	396.64	8.56
Advanced	2045	368.83	8.14
Advanced	2050	341.01	7.73
Conservative	2022	852.09	14.57
Conservative	2023	850.41	14.52
Conservative	2030	838.64	14.19
Conservative	2035	766.56	13.35
Conservative	2040	694.49	12.51
Conservative	2045	622.41	11.67
Conservative	2050	550.34	10.83
Moderate	2022	820.05	14.19
Moderate	2023	786.34	13.77
Moderate	2030	550.34	10.83
Moderate	2035	525.82	10.47
Moderate	2040	501.3	10.12
Moderate	2045	476.78	9.77
Moderate	2050	452.26	9.43

4.1.3.1.4 PPOA Model

The PPOA model is much more complex than the simple FCR model and a thorough description may be found in Section 8.2.6 (page 217); however, we provide in this section a general description of the notable components of the model for context. The PPOA model can incorporate either the production tax credit (PTC) or the investment tax credit (ITC) into its LCOE estimates. The ITC was found to be consistently more valuable than the PTC in this for utility-scale PV in Puerto Rico, so this is what we used. The ITC was set at a 30% rate out to 2033 and was then progressively reduced to 0% by the end of 2035, when the program expires. At this point, the model assumed no incentive program replacement and overall cost reductions resumed the trajectory set by the 2022 ATB (NREL 2022b).

Importantly, a recent amendment to the initial PPOA LCOEs added significant costs to previous estimates resulting in an increase in the original location factor from an original 1.39 to 2.25 (see Section 10.2.5). Because the effect of this cost increase was attributed to recent disruptions in global supply chains, we reduce this latter factor down to the original 1.39 by 2035. This was done linearly such that the location factor in the PPOA calculation follows the trajectory shown in the Figure 33.

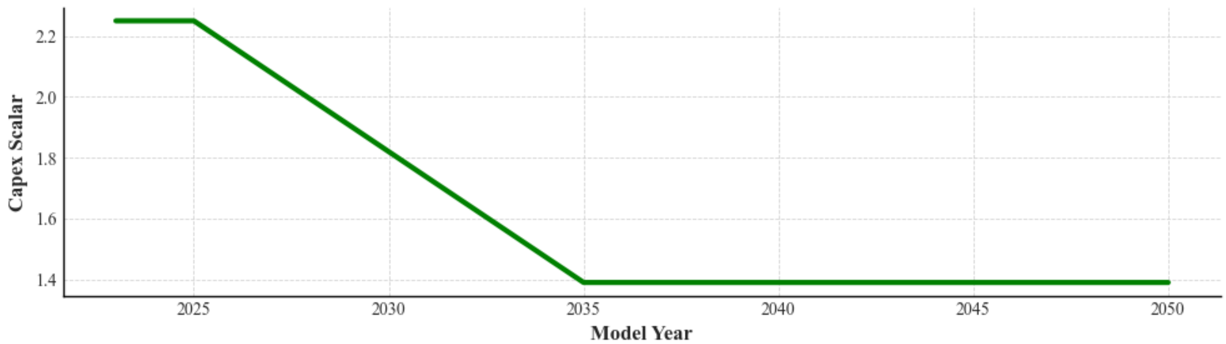

Figure 33. Capital cost multipliers by year, used only in the PPOA model

4.1.3.1.5 Economies of Scale

When appropriate data are available, the reV model can capture per-unit capital cost reductions associated with larger plants and adjust LCOEs accordingly. To do this, a cost curve must be developed that captures the cost reduction at increasing capacity bins. We use NREL's 2021 solar benchmarking study (Ramasamy et al. 2022) to derive a suitable curve. The benchmarking study only provides costs for plants up to 100 MW_{DC}, but plants that are significantly over 100 MW_{DC} are unlikely to be built in Puerto Rico: The largest current plant in Puerto Rico is the Oriana Solar plant at 57.7 MW_{DC}, and the largest plant currently planned is the AES Salinas Solar plant at 120 MW_{DC} (PREB 2022). Here it is important to highlight that the technical potential estimates generated by the reV model represent the maximum capacity that is technically possible in an area; they do not predict the actual capacity of a solar plant. Capacity expansion models that use these outputs extract only the amount of capacity needed from a reV cell to solve the deployment scenario, and so the costs should reflect this extractable capacity.

So, to take advantage of the information provided in the benchmarking study (Ramasamy et al. 2022), we adjusted the economies of scale curve to fall in price from 5 MW_{DC} to 100 MW_{DC}, where it then levels out for lack of data. The shape of this curve can be seen in Figure 34.

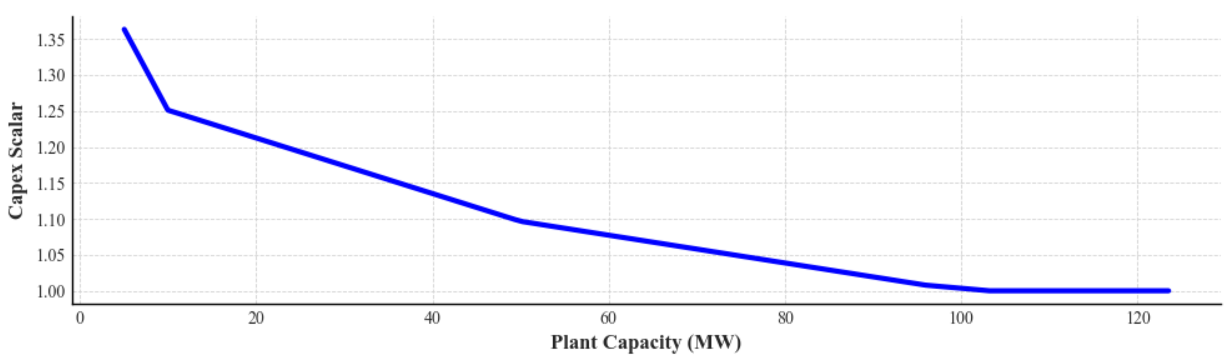

Figure 34. Capital cost multipliers by capacity, used in both the simple FCR and PPOA LCOE models

4.1.3.1.6 Generation and System Design

We used the ATB to configure the SAM system parameters associated with a baseline technology year (2023) and three advancement scenarios associated with future years (Table 12). These advancements scenarios, referred to as the Conservative Technology, Moderate Technology, and Advanced Technology scenarios, were used to represent different possible cost and performance trajectories. An important feature to note is that to better understand the cost and performance trajectories modeled in PR100 is the inclusion of bifacial PV modules, or energy generation from both sides of a PV module. A bifaciality factor was included in system designs starting in 2030 for the Moderate Technology and Advanced Technology system designs and was defined as the ratio of energy generation from the module's rear surface relative to the front (Prilliman and Freeman Keith 2022). Prilliman and Keith (2022) describe this factor in detail and analyze the uncertainties associated with SAM's implementation of this parameter. Through an examination of existing plants in Puerto Rico and discussions with local utility-scale solar developers, it was determined that the single-axis tracking systems that are common in the 50 U.S. states were not appropriate for Puerto Rico and so we use a fixed-tilt mounting structure. A summary of system design parameters used in the SAM model is available in Table 12.

Though all cost and performance years are available, ATB system design parameters are only available for the baseline year and 2030. However, the ATB does model yearly improvements in generation efficiencies using learning curves and other statistical modeling, which are reported as average capacity factors for each year out to 2050. Therefore, to capture generation improvements over time, a time-series of generic capacity factor improvement ratios were calculated using 2023 as the baseline. These values were applied to the average capacity factor calculated by reV at each site. Doing so maintained the site-specific generation variation expected by the specific system design described below while incorporating the effect of expected technological advancements. All figures in Table 12 were derived from the 2022 ATB release (NREL 2022b).

Table 12. System Parameters

Parameter	Baseline	Conservative	Moderate	Advanced
Year	2023	2030	2030	2030
Albedo	0.2	0.2	0.2	0.3
Azimuth	180°	180°	180°	180°
Bifaciality factor	0	0	0.85	0.85
Capacity density	70 MW_{DC}/km^2	70 MW_{DC}/km^2	70 MW_{DC}/km^2	70 MW_{DC}/km^2
DC/AC ratio	1.28	1.28	1.28	1.28
Ground cover ratio	0.44	0.44	0.44	0.44
Inverter efficiency	96%	96%	98%	98.5%
Losses	14.3	14.3	10.4	7.5
Panel type	Standard monocrystalline	Standard monocrystalline	Standard monocrystalline	Standard monocrystalline

4.1.3.1.7 Land Use Assumptions

Land use assumptions in reV are intended to recreate development restrictions in a study area, and they include both physical barriers and regulatory restrictions. These assumptions were translated into a gridded inclusion layer that was used to set the capacities of each model plant and refine generation and cost estimates. Because Puerto Rico is highly land-constrained, we used a 10-m resolution inclusion grid (which was significantly finer than the model's default 90-m grid) to better capture detailed land use patterns. After consultations with the Advisory Group, we decided that the 2015 Puerto Rico Land Use Plan (Puerto Rico Planning Board 2015) would serve as the basis for these assumptions. This land use plan delineates different categories of agricultural, ecological, hydric, landscape, and urban land categories. A map of this plan can be seen in Figure 35 and a legend describing the categories is available in Table 13.

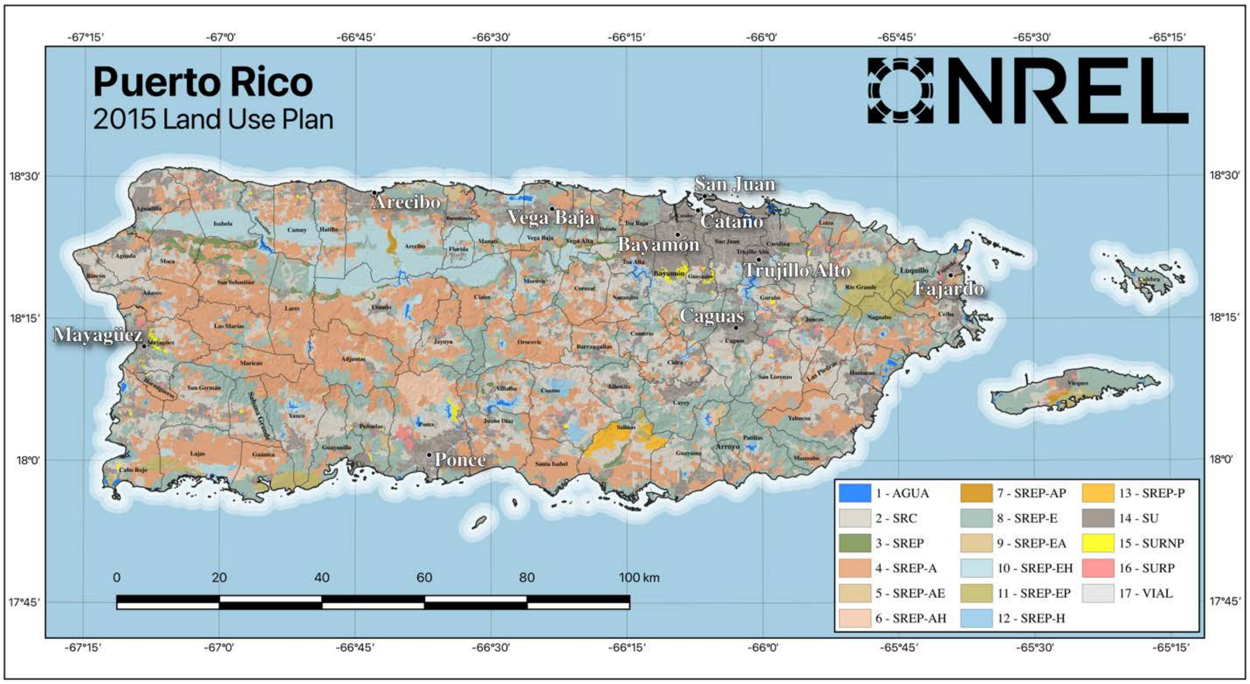

Figure 35. 2015 Puerto Rico Land Use Plan Map

Source: Puerto Rico Planning Board (2015)

Table 13. 2015 Puerto Rico Land Use Plan Categories

Acronym	Full Name
AGUA	Water
SRC	Rustic Common
SREP	Specially Protected Rustic Land
SREP-A	Specially Protected Rustic Land – Agricultural
SREP-AE	Specially Protected Rustic Land – Agricultural/Ecological
SREP-AH	Specially Protected Rustic Land – Agricultural/Hydric
SREP-AP	Specially Protected Rustic Land – Agricultural/Landscape

Acronym	Full Name
SREP-E	Specially Protected Rustic Land – Ecological
SREP-EA	Specially Protected Rustic Land – Ecological/Agricultural
SREP-EH	Specially Protected Rustic Land – Ecological/Hydric
SREP-EP	Specially Protected Rustic Land – Ecological/Landscape
SREP-H	Specially Protected Rustic Land – Hydric
SREP-P	Specially Protected Rustic Land – Landscape
SU	Urban Land
SURNP	Urbanizable Land – Not Programmed
SURP	Urbanizable Land – Programmed
VIAL	Road Network

In 2019, the state planning board implemented an updated land use plan that was less restrictive for development projects in Puerto Rico and was not well received by the public, according to the planning board. Use of the older 2015 plan is expected to, to some degree, preclude conflict between agriculture, conservation, and renewable energy. An illustrative example of this type of conflict can be seen in a recent lawsuit lodged by environmental groups against the Puerto Rico government (PRLC vs PRPB 2023). In the lawsuit, the plaintiffs assert that a large set of upcoming solar projects (Tranche 1) were approved for installation on special agricultural reserves and specially protected rustic land in violation of local regulations.

Shifts in land use priorities over time resulting from lawsuits such as this or others like it cannot be predicted. To account for this uncertainty, we used two future land availability variations to restrict developable land in the model. The first variation, referred to as Less Land, restricts development from all high-value agricultural, ecological, hydric, and landscape land categories. This variation does not allow for any deployment in the land use categories disputed in PRLC vs PRPB 2023. The second access variation, referred to as More Land, relaxes these constraints and includes specially protected rustic agricultural land categories from the land use plan. However, the More Land variation still completely excludes special agricultural reserve land, ecological, landscape, and hydric categories from development. Both variations also exclude high slope areas, water bodies, buildings, Federal Emergency Management Agency (FEMA) flood hazard zones, natural protected areas, habitat areas of critical concern (HAPC), airports, roads, transmission lines, and substations. The land use plan categories and these secondary data sets include some redundancies, but this helps ensure the model does not deploy on undevelopable land. A complete list of exclusion assumptions for each category is shown in Table 14.

Table 14. More and Less Land Variation Exclusions and Inclusions

Category	Less Land	More Land	Source
Agricultural Reserves	Exclude	Exclude	JP[a]
Airports	Exclude	Exclude	HOTOSM[b]
Buildings	Exclude	Exclude	HOTOSM
Flood Hazard Zones > 1% Annual Chance	Exclude	Exclude	FEMA[c]

Category	Less Land	More Land	Source
HAPC	Exclude	Exclude	PRPB[d]
Land Use Plan – AGUA	Exclude	Exclude	PRPB
Land Use Plan – SRC	Include	Include	PRPB
Land Use Plan – SREP	Exclude	Include	PRPB
Land Use Plan – SREP-A	Exclude	Include	PRPB
Land Use Plan – SREP-AE	Exclude	Include	PRPB
Land Use Plan – SREP-AH	Exclude	Include	PRPB
Land Use Plan – SREP-AP	Exclude	Include	PRPB
Land Use Plan – SREP-E	Exclude	Exclude	PRPB
Land Use Plan – SREP-EA	Exclude	Exclude	PRPB
Land Use Plan – SREP-EH	Exclude	Exclude	PRPB
Land Use Plan – SREP-EP	Exclude	Exclude	PRPB
Land Use Plan – SREP-H	Exclude	Exclude	PRPB
Land Use Plan – SREP-P	Exclude	Exclude	PRPB
Land Use Plan – SU	Exclude	Exclude	PRPB
Land Use Plan – SURNP	Include	Include	PRPB
Land Use Plan – SURP	Include	Include	PRPB
Land Use Plan – VIAL	Exclude	Exclude	PRPB
Minimum Contiguous Area	0.071 km^2	0.071 km^2	Area required for a 5-MW plant
Natural Protected Areas	Exclude	Exclude	PA-CAT[e]
Slope	> 10%	> 10%	USGS NED[f]
Substations	Exclude	Exclude	LUMA
Transmission	Exclude 45-m Buffer	Exclude 45-m Buffer	LUMA
Water Bodies	Exclude	Exclude	USGS NHD[g]

[a] Junta de Planification (JP): Puerto Rico Agricultural Reserves. Accessed 2023. https://sige.pr.gov/server/rest/services/MIPR

[b] Humanitarian Open Street Map (HOTOSM): Puerto Rico Buildings. Accessed 2022. https://data.humdata.org/dataset/hotosm_pri_buildings

[c] FEMA, Flood hazard areas for Puerto Rico. Accessed 2023. https://hazards.geoplatform.gov/server/rest/services/Region2/Advisory_Base_Flood_Elevation__ABFE__Data/MapServer/

[d] Puerto Rico Planning Board (PRPB) https://databasin.org/datasets/7f1cc5f0febc40829e5845df556981fe/

[e] Protected Areas Conservation Action Team (PA-CAT), Protected Areas. Accessed 2022. https://databasin.org/datasets/4db5a86ee415471f94b46e0975a1ae29/

[f] United States Geological Survey National Elevation Dataset (USGS NED). Accessed 2022. https://www.usgs.gov/publications/national-elevation-dataset

[g] United States Geological Survey National Hydrography Dataset (USGS NHD). Accessed 2022. https://www.usgs.gov/national-hydrography/national-hydrography-dataset

In addition to modeling explicit land use restrictions, the reV model excludes highly fragmented land from development using a contiguous area filter. For PR100, roads were not included in this step, as most of these are small dirt roads and were not observed to prevent development in the existing plants in Puerto Rico. Using the area filter, sites with less than 0.071 km^2 of contiguous land were removed from the inclusion layer; this value represents the minimum area required for a utility-scale plant (5 MW_{DC}) using a capacity density assumption of 70 MW_{DC}/km^2. The utility-scale capacity threshold of 5 MW_{DC} was chosen to align with the 2022 U.S. solar photovoltaic system and storage cost benchmarking study (Ramasamy et al. 2022) that serves as the basis for UPV's representation in ATB. The derivation of the capacity density value is described in the next section. Notably, the reV model will split this available land into grid cells, which in some cases will reduce smaller parcels of available land to below the 5-MW_{DC} threshold. A second capacity threshold was then applied to the supply curve tables, meaning the total capacity inferable from this inclusion layer would usually be slightly larger than that represented in the final outputs.

4.1.3.1.8 Capacity Density

PR100 assumed significant improvements in land use efficiency for utility-scale PV over assumptions used in previous NREL technical potential studies. Here, we refer to this efficiency variable as "capacity density," which we define as an amount of capacity per unit area. reV used this value to calculate the total capacity of each model plant after the available area was determined in the exclusion step. Because of the centrality of capacity in this analysis, this was one of our most important input assumptions. Therefore, to determine an appropriate representative value for Puerto Rico, we performed an analysis of existing solar densities and expected trends.

Empirical capacity estimates may be associated with different methods for delineating the boundaries of a utility-scale PV plant. As illustrated in Figure 36 (page 83), the boundary may represent (1) the parcel owned or leased by the developer, (2) the fenced or disturbed area within the parcel in which operations take place, or (3) the area immediately surrounding the actual photovoltaic arrays. For a planned plant, the only area, if any, a researcher might have access to is the parcel area. There is a large variety of land use patterns at this scale, and it is often much larger than the fenced/disturbed area that the facility occupies, so without additional information about the land use plan of the developer, this information is not very useful for a detailed analysis such as ours for PR100. For existing plants, it is possible to delineate the disturbed area boundary with reasonable accuracy from satellite imagery if the fenced area is not directly retrievable from public sources. Capacity density estimates for this type of area were significantly more precise than those for ownership level boundaries, though they still varied considerably. Density estimates based on the direct array area represent the highest level of precision possible. However, the reV model cannot yet model land use with that level of precision, and so the disturbed area capacity density is more appropriate.

While undevelopable lands are explicitly modeled, design decisions such as the appropriate placement of service roads, transformers, substations, inverters, and buffer zones around facilities have not yet been incorporated into the methodology. Additionally, design decisions affecting the ultimate capacity density of a plant will vary due to local regulations and business considerations, elements that are also outside the current capabilities of the model. Ideally, this would recreate the decision-making process of a typical developer and generate a unique density value appropriate for each site. This represents an area of potential improvement and is being actively considered. In the meantime, we were limited to the standard practice of using a single constant value to represent a typical plant. It is important to note that this value may be lower than the highest observations seen today, but we hope that this will sufficiently capture the variation of capacity density estimates across Puerto Rico while capturing technological improvements over time.

To define the appropriate capacity density value for Puerto Rico, there are three general sources of empirical data from which to draw: (1) industry-wide assessments of common and expected density values, (2) densities associated with a handful of existing large-scale plants in Puerto Rico, and (3) the capacities and site boundaries of planned plants in Puerto Rico. Of these, the most precise estimates may be drawn from existing utility-scale plants in Puerto Rico, though these may not represent recent space-saving innovations and are limited in number (six).

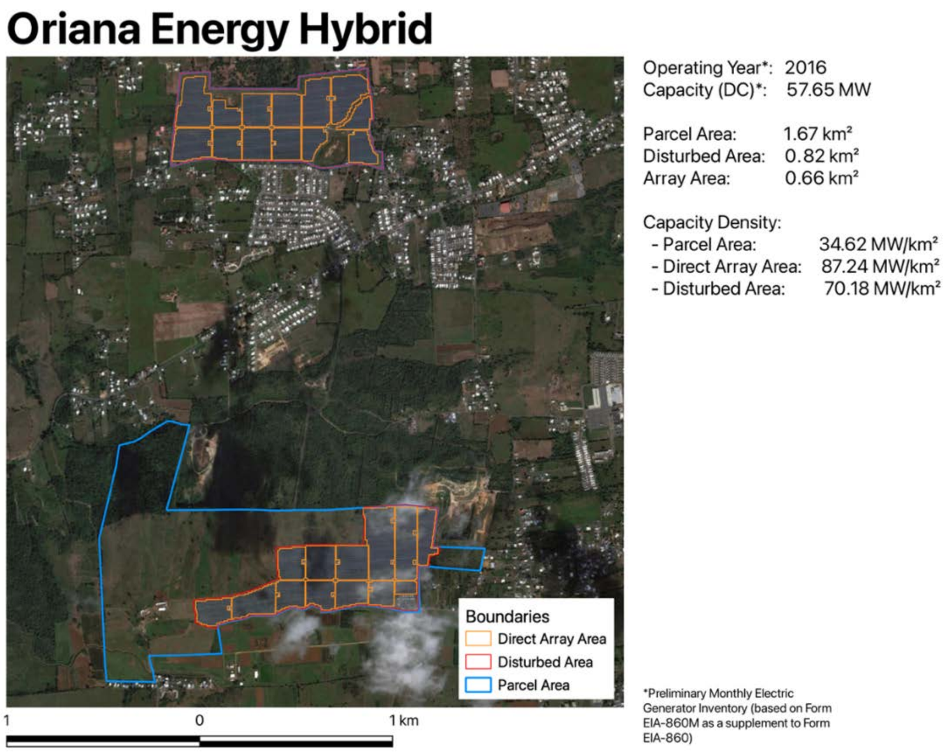

Figure 36. Example of solar plant boundary delineations using the Oriana Energy Hybrid plant in Isabela, Puerto Rico

In this case, the plant was split into two parts, only one of which was associable with a parcel boundary.

The set of planned plants provides valuable insight into near-future planned capacities, but the ultimate disturbed areas are not yet observable, and the target capacities associated with each project have not yet been achieved. The industry-wide assessments represent a much larger sample size, and though they provide more insight into the effects of innovations over time, they do not reflect local practices. Each type has value and limitations, so assimilating each into a singular representative capacity density value is challenging. In this case, the uncertainties and limitations associated with the planned plant capacities and land use plans were determined to be too great, so only the existing plants and industry-wide assessments were used here.

To begin, we generated estimates of capacity density for each of the six existing utility-scale plants in Puerto Rico. Boundaries representing the direct array and disturbed area were manually digitized using GIS software (QGIS),[80] OpenStreetMap[81], and satellite imagery.[82] Reported plant capacities for each plant[83] were associated with areas from these boundaries and used to create capacity density estimates for each delineation of area. Ratios between the disturbed and direct array areas were also calculated for each plant. An example of the results of this exercise is shown in Figure 36. The accuracy of this process was directly validated for two plants using official estimates provided by correspondence with Infinigen Renewables, which manages the Oriana and Horizon solar plants. According to Infinigen, the capacity densities for the Horizon and Oriana Solar plants were 63.45 and 70.52 MW_{DC}/km^2 respectively, while the disturbed area estimates derived here were 63.23 and 70.18 MW_{DC}/km^2. The average ratio between the direct array and disturbed area was 0.72.

Recent research by Lawrence Berkeley National Laboratory uses project-level U.S. Energy Information Administration (EIA) reporting and satellite imagery analysis to show a clear increase in densities across the United States over time (Bolinger and Bolinger 2022). These increases are attributed primarily to increasing ground cover ratios and module capacities; they are also found to align well with international estimates. Bolinger and Bolinger (2022) calculate the average direct array area capacity densities in 2019 to be 86.45 MW_{DC}/km^2 for fixed-axis systems. Bolinger and Bolinger (2022) also find a positive linear trend in density as latitude decreases. According to a trend line derived from density estimates in this study, the density expected at Puerto Rico's latitude (using the center of the main island at 18.21 degrees) rises to 98.51 MW_{DC}/km^2. After applying the direct array to disturbed area ratio of 0.72, this value becomes 69.94 MW_{DC}/km^2, and this value was verifiably reached by the Oriana project, the largest current solar plant in Puerto Rico, according to Infinigen. Bolinger and Bolinger (2022) also note that further improvements in densities are expected in the coming years due to emerging technologies such as bifacial panels. Therefore, despite the significant increase in density assumptions over previous studies, 70 MW_{DC}/km^2 (54 MW_{AC}/km^2) may actually be interpreted as a somewhat conservative estimate for achievable density. However, considering the variability of densities observed thus far, it provides a reasonable representative value for all plants that are likely to be built in Puerto Rico.

4.1.3.2 Results

In reporting results, added attention is given to the Less Land variation and Moderate Technology Advancement scenario because these are considered more likely for Puerto Rico. However, results for each model year, technology combination, and land use variations are reported in this section.

[80] "QGIS" QGIS Association, accessed 2023, http://www.qgis.org.
[81] https://www.openstreetmap.org
[82] "ArcGIS REST Services Directory: World_Imagery (MapServer)," Esri, Maxar, Earthstar Geographics, and the GIS User Community, accessed 2023, https://services.arcgisonline.com/ArcGIS/rest/services/World_Imagery/MapServer.
[83] "Preliminary Monthly Electric Generation Inventory for Puerto Rico," EIA, accessed 2022, https://www.eia.gov/electricity/data/eia860m/.

4.1.3.2.1 Capacity and Generation

The Less Land variation resulted in 203 km^2 of developable land with the largest area in Salinas and significant area spread across the northwest coast of the main island (Figure 37). This result translates to about 14.7 GW_{DC} of capacity for the fixed-tilt system assumption of 70 MW_{DC}/km^2 (54 MW_{AC}/km^2). However, because of the 5-MW_{DC} utility-scale threshold and gridding effect described in Section 4.1.3.1.7, this value was reduced to 14.2 GW_{DC}. The More Land variation resulted in 638 km^2 of available land including significant swathes across the central southern coast and the northwestern coast, and in 420 km^2 of the agricultural categories in the specially protected rustic land group (Figure 38). The More Land variation translates to 45.1 GW_{DC}, which was reduced to 44.67 GW_{DC} because of the gridding effect mentioned above. The total assessed land area is 8,940 km^2, so these scenarios identify 2.34% and 7.3% of the total area as developable in the Less Land and More Land variations respectively.

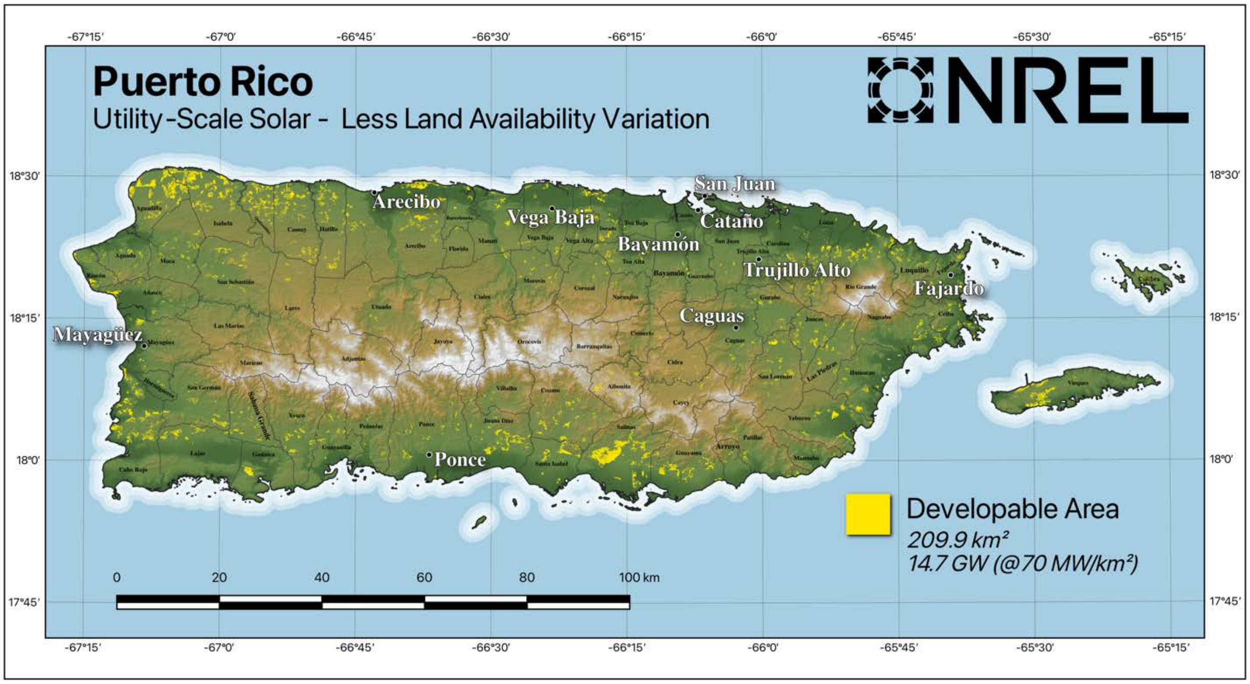

Figure 37. Developable area for utility-scale solar PV in the Less Land scenario

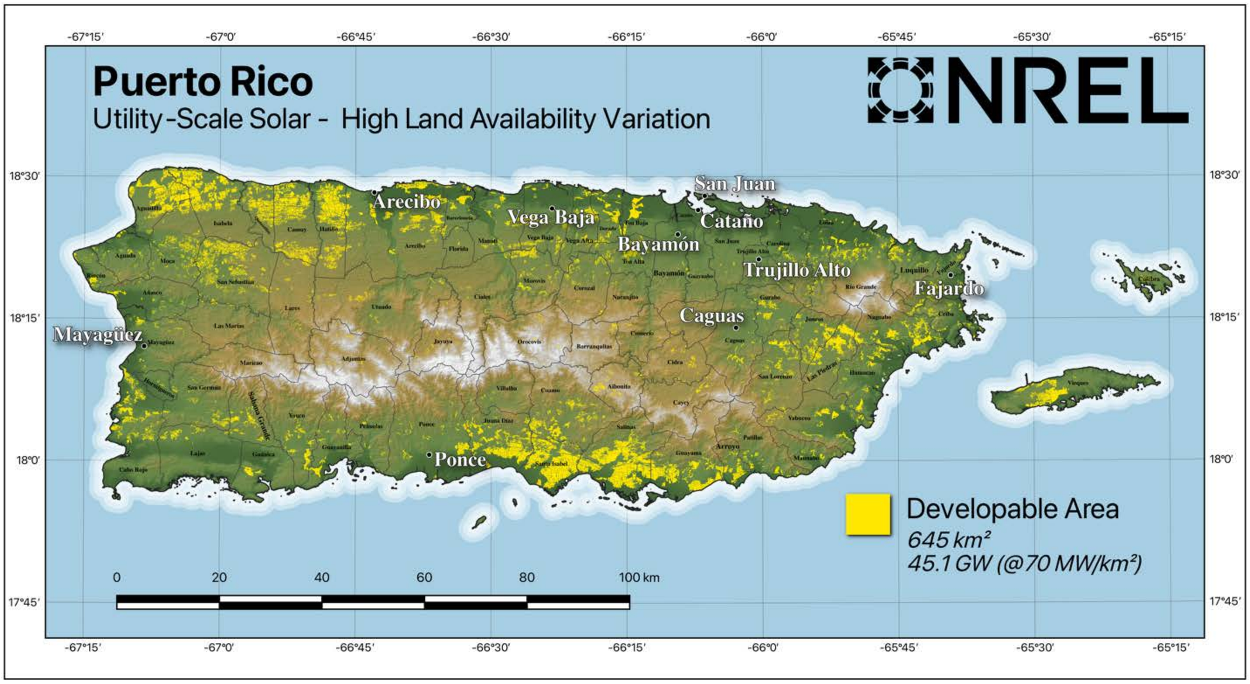

Figure 38. Developable area for utility-scale solar PV in the More Land scenario

The municipality of Salinas was found to provide the most capacity: 1.26 GW in the Less Land variation and 3.66 GW in the More Land variation. After Salinas, there was a significant difference between the two scenarios: Aguadilla, Isabela, and Cabo Rojo rank second through fourth in the Less Land scenario with 1.01 GW, 0.80 GW, and 0.75 GW respectively, while Santa Isabel, Hatillo, and Isabela rank second through fourth for the More Land variation with 3.01 GW, 2.41 GW, and 1.96 GW (Figure 39).

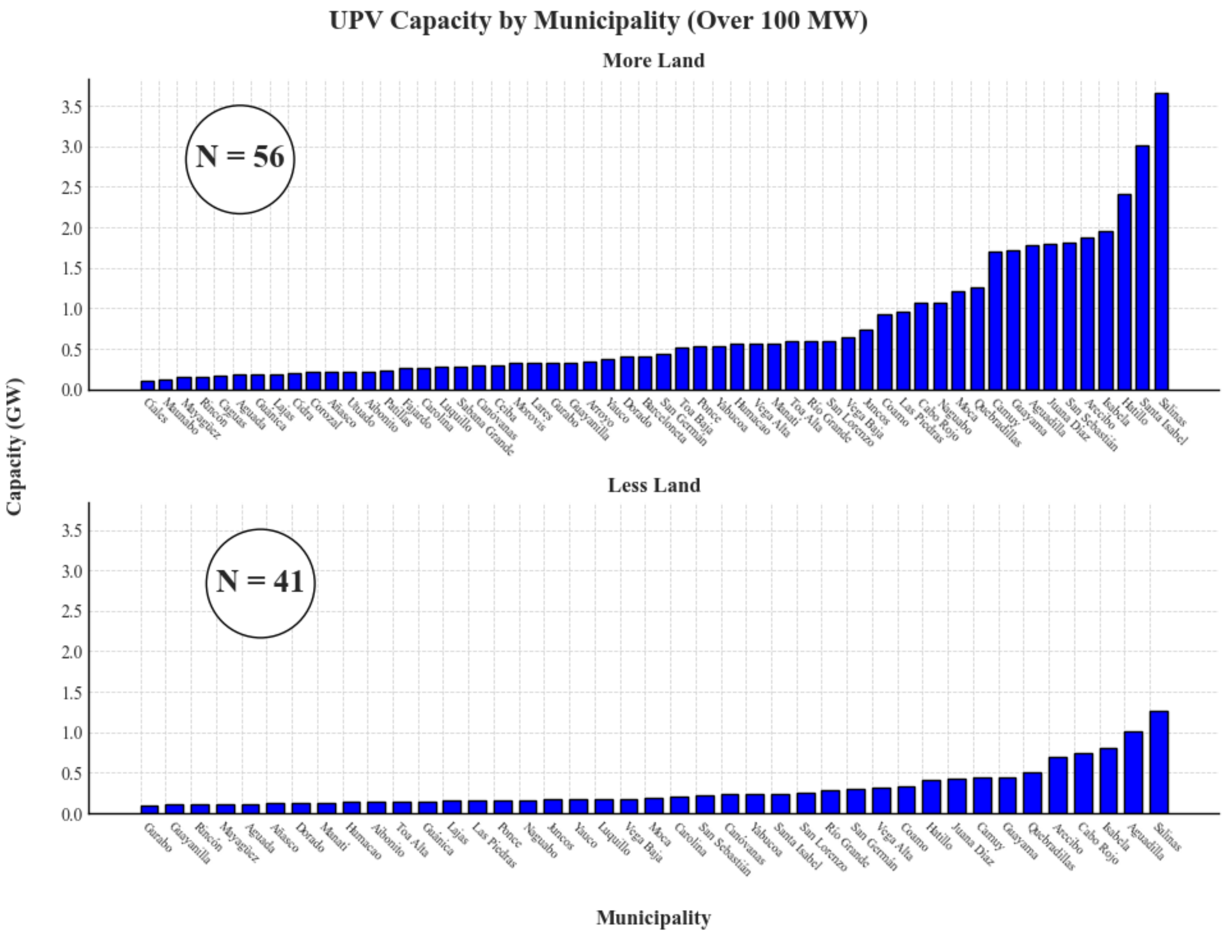

Figure 39. Capacity by municipality for the Less Land and More Land scenarios

The figure shows only municipalities with more than 100 MW of technical potential.

Annual energy production (AEP) in the Moderate and Advanced Technology scenarios is seen to rise steadily over the time-period with a more significant jump from the baseline year to 2030 because of a larger gap between model years and the addition of bifaciality. For the Conservative case, AEP also rises, but at a much slower pace and with no jump between the first two model years, highlighting the importance of bifaciality (Figure 40). From 2023 to 2050, total AEP in the Less Land variations rises from 22.59 GWh/yr to 25.27 GWh/yr in the Conservative case, 23.05 GWh to 27.67/yr GWh/yr in the Moderate case, and 23.17 GWh/yr to 29.02 GWh/yr in the Advanced case. In the More Land variation, these values are 70.91 GWh to 79.32 GWh in the Conservative scenario, 72.37 GWh to 86.87 GWh in the Moderate scenario, and 72.73 GWh to 91.09 GWh in the Advanced scenario.

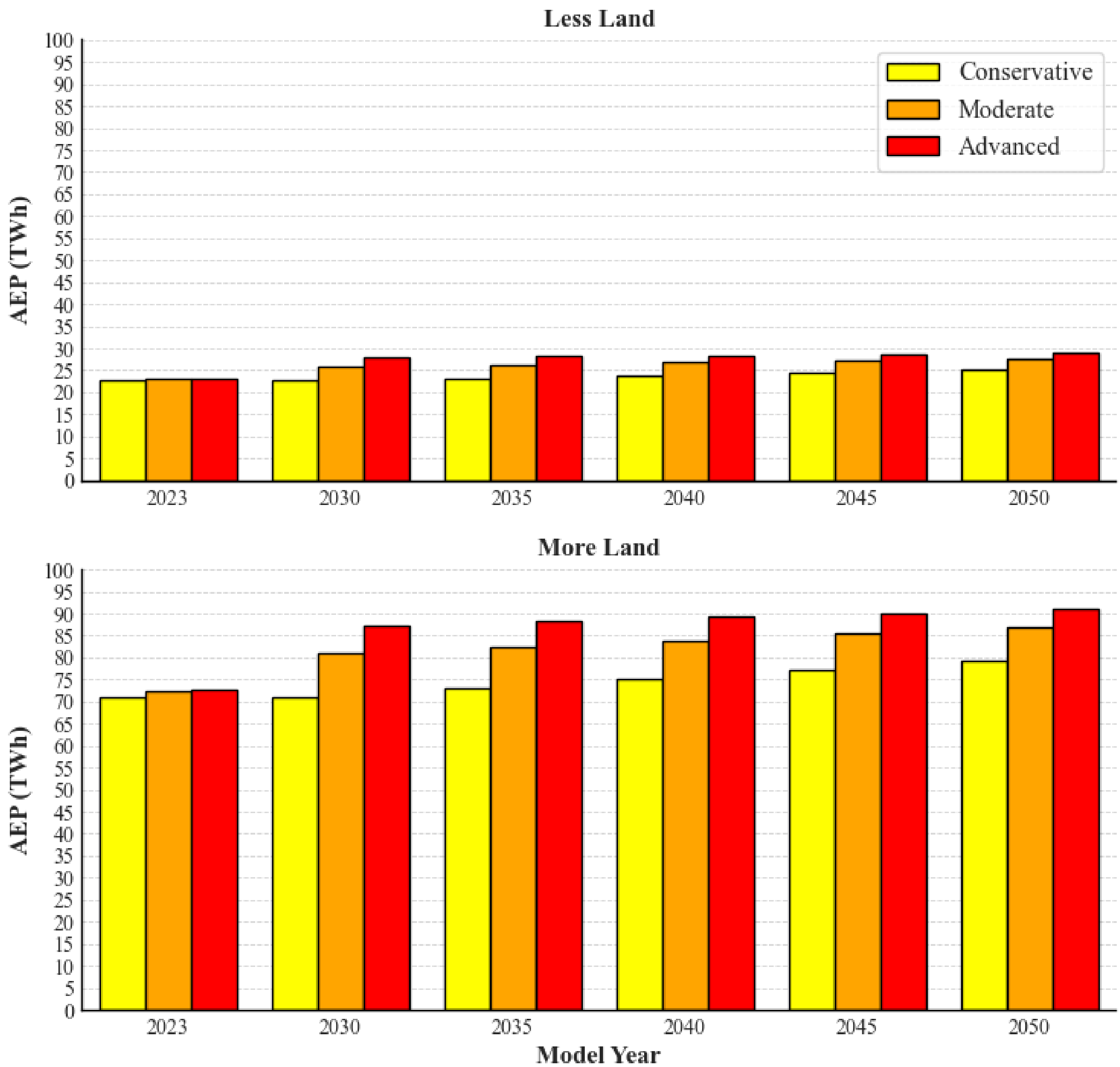

Figure 40. Annual energy production (AEP) for each technology scenario in the Less Land and More Land variations through 2050

There is little difference in annual generation ranking by municipality when compared to the rankings for capacities because of the relatively consistent solar resource across Puerto Rico. However, in several examples, including San Germán, San Lorenzo, and Vega Baja, generation is higher despite less available capacity, indicating better resource potential in those areas. In each land access scenario case, the top-four locations in terms of capacity maintain their relative positioning in terms of AEP. Salinas again has the most potential in both with 2,329/yr and 6,823 GWh/yr for Less and More Land, Moderate Technology respectively, followed by Aguadilla, Isabela, and Cabo Rojo in the Moderate Less Land variation with 2,044, 1,600, and 1,428 GWh while Santa Isabel, Hatillo, and Isabela are the next three highest in the Moderate More Land variation with 6,077, 4,707, and 3,920 GWh. Across years, these rankings do not change, but to provide a sense of scale for the improvements expected by 2050, the modeled AEP values for this year in Salinas range from to 2,281 to 2,619 GWh in the Less Land variation and 6,681 to 7,673 GWh in the Advanced case (Figure 41).

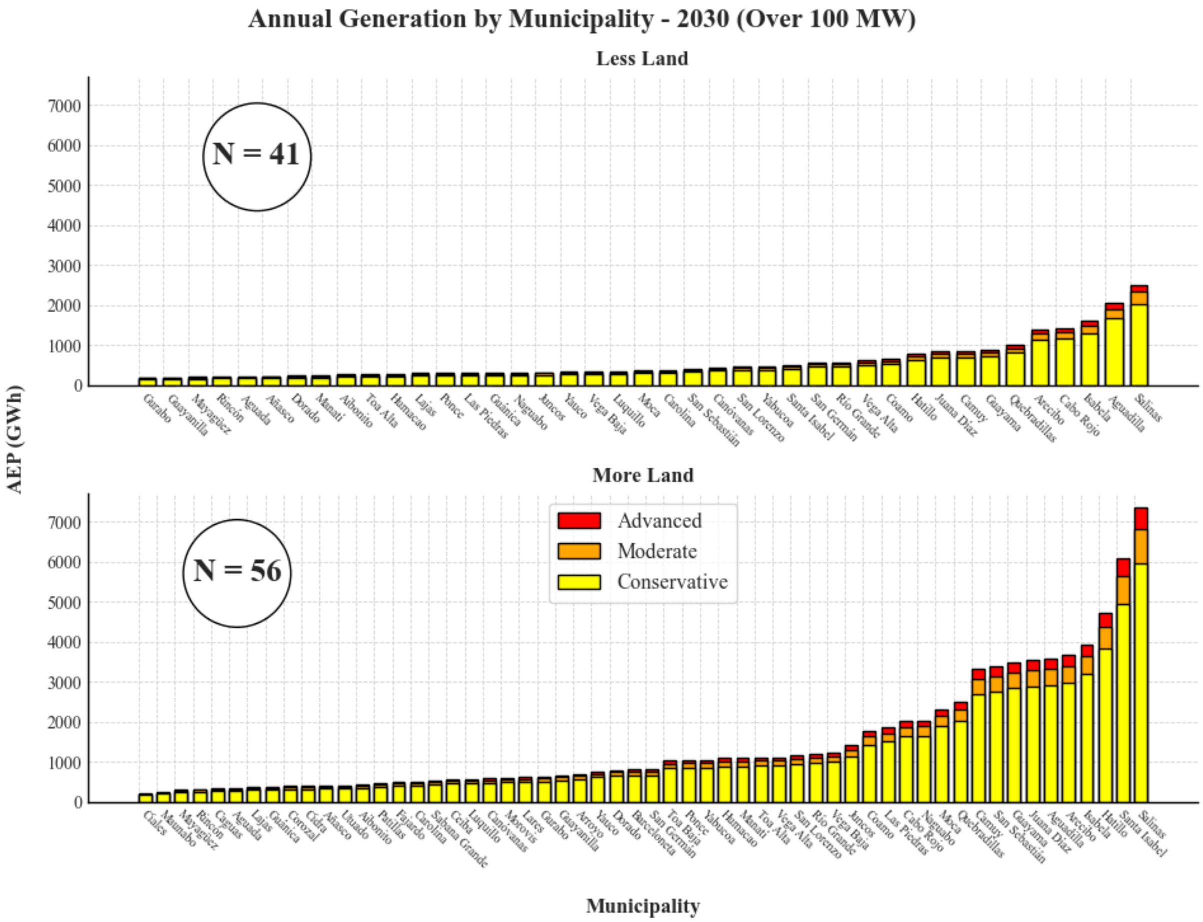

Figure 41. AEP by municipality for the Less Land and More Land scenarios and the Conservative Technology, Moderate Technology, and Advanced Technology scenarios

4.1.3.2.2 Costs

There was a dramatic difference in costs between the simple FCR LCOE model and the PPOA model. Within the LCOEs from either model, there was a wide range of potential LCOE values. Each value was influenced by a site's location, the model year, the land availability scenario via economies of scale, and the technology advancement scenario.

In the ATB model, the Moderate Technology/Less Land case for the model year 2023 resulted in LCOEs ranging from $32.46'MWh to $47.11/MWh with a capacity-weighted average of $37.04/MWh. Across all three technology scenarios and both land use scenarios, these values ranged from $31.44/MWh to $51.70/MWh. While these values were significantly lower than cost assessments from only a few years ago, they were well in line with more recent assessments. Lazard's most recent LCOE report (Lazard 2023) estimates range from $24/MWh to $96/MWh, NREL's 2022 utility-scale PV benchmarking study (Ramasamy et al. 2022) places this value at $41/MWh for a representative plant in the 50 U.S. states and the 2022 ATB (NREL 2022b) estimates the range at $32/MWh to $52/MWh. The ATB LCOE range in the benchmarking study is notable because, though the physical modeling process differs in many ways, it shares the same model costs and many of the same system design parameters with PR100. Because the ATB model estimates represent a system in the 50 U.S. states where solar resource is typically weaker and less consistent, a resource-driven reduction in production costs is expected in Puerto Rico. Average median, minimum, maximum, and inner quartile values of LCOE values for the ATB model in each model year and scenario are displayed in Figure 42.

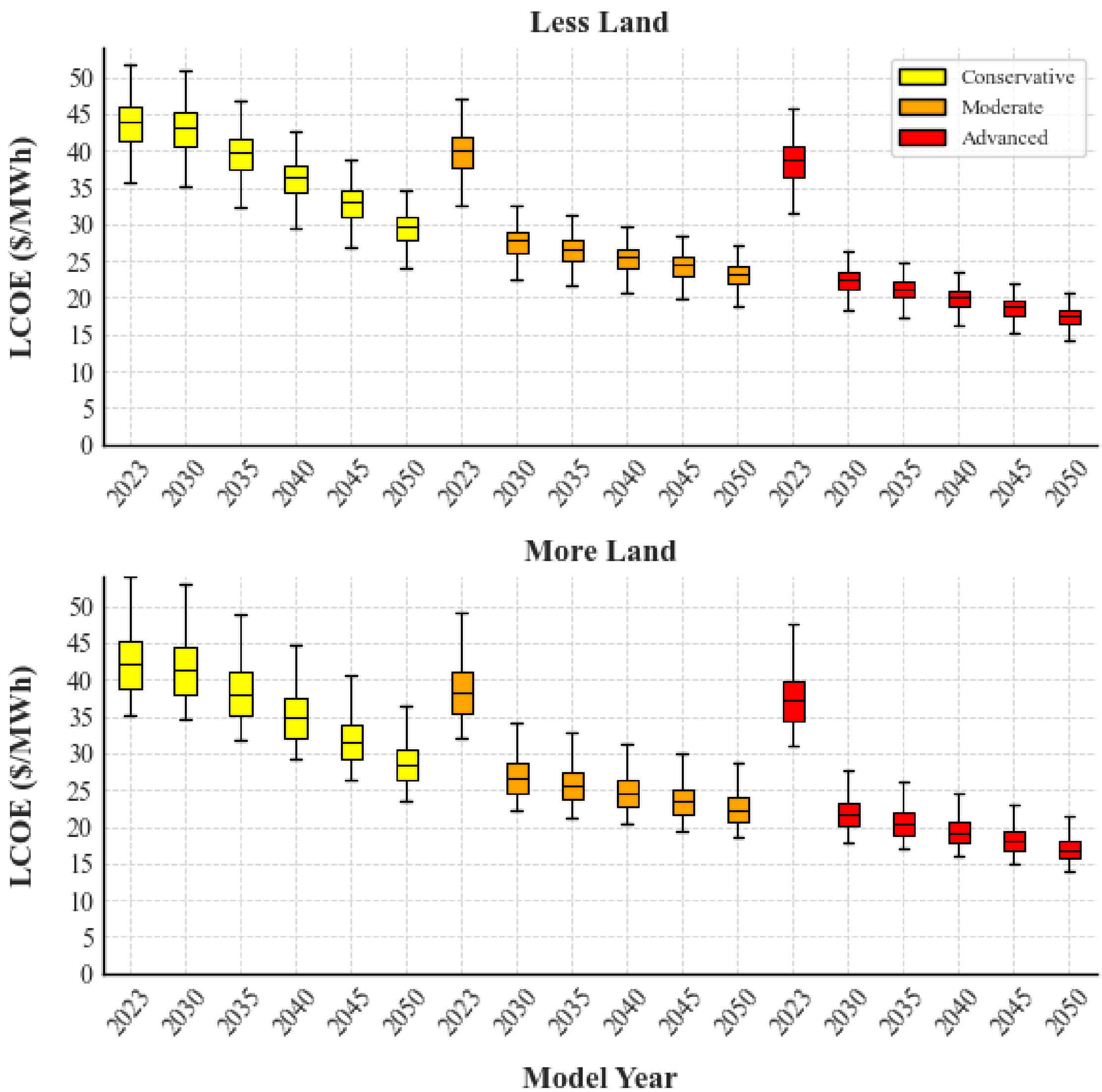

Figure 42. Simple FCR LCOEs for each model year and technology advancement scenario for the Less Land and More Land scenarios

The LCOEs from the PPOA model for the 2023 Moderate Technology/Less Land case ranged from $142.09/MWh to $210.58/MWh and had a capacity-weighted average of $179.83/MWh. While electricity rates in Puerto Rico are consistently twice as high as those in the 50 U.S. states this value was dramatically higher than the standard model estimates. The current prices reflect recent supply chain issues from the COVID-19 pandemic and other events affecting the international market, while future prices include cost increase factors that reduce over time. Prices fell consistently below $80/MWh in the Moderate and Advanced Technology case after 2030. In the yearly trajectory for each scenario, the LCOEs fell from 2023 to 2035, rose in 2040 due to the expiration of the ITC, then fell continuously to 2050. Across all three technology scenarios and both land use variations in the baseline year, these values ranged from $242.09/MWh in a 2023 Conservative Technology/More Land site to $39.32/MWh for a 2050 Advanced Technology site. Modeled 2023 values for LCOE from the PPOA model in each model year and technology scenario are displayed in Figure 43.

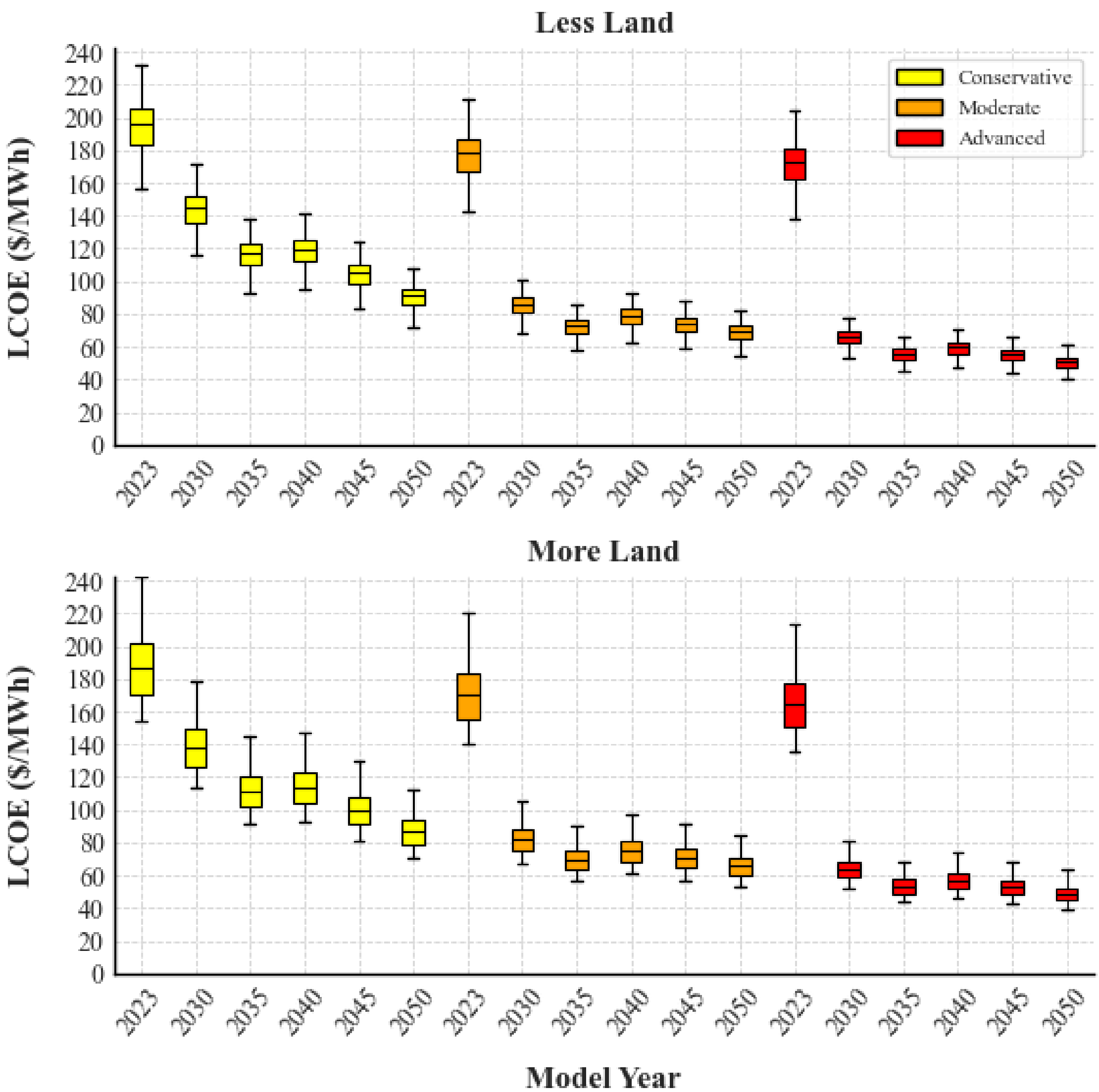

Figure 43. PPOA LCOEs for each model year and technology advancement scenario for the Less Land and More Land scenarios

The effect of local financial conditions in Puerto Rico can be examined by comparing the cost trajectories of the two cost models. Because the simple LCOE is based on generic assumptions for falling costs and increasing efficiency, a time-series of its costs can be seen as the baseline trajectory for utility-scale PV. Deviations from this pattern are generally attributable to the higher capital and operating costs in Puerto Rico than in CONUS, higher financing costs, the effect of the ITC, and, for results out to 2035, the assumption that utility-scale PV supply chains will return to pre-COVID pandemic conditions. These are not the only factors explaining deviation—only the most significant ones. There are many other nuances involved with the PPOA model as it is a highly complex cost model tailored specifically for Puerto Rico.

As described above, there was an obvious effect on the overall magnitude of costs between the models. For the Less Land scenarios in 2023, the PPOA model was on average 4.43, 4.42, and 4.42 times higher for the Conservative Technology, Moderate Technology, and Advanced Technology scenarios, respectively. For the Less Land variation in 2023, these values fell to 3.33, 3.07, and 2.93 times the ATB model outputs and by 2050 these values settled at 3.05, 2.94, and 2.88.

Both cost models resulted in a significant initial drop in LCOEs from 2023 to 2030 for the Advanced and Moderate Technology scenarios. These drops were primarily due to technological advancement, but the magnitude of the drop in the PPOA model was greater (about 56% versus 36% reduction in average prices), which shows the effect of the ITC and the assumption of a return to normal market conditions with falling capital and operating cost multipliers. In the Conservative Technology scenario, for the ATB model, the drop between the first two time-steps was minimal (1.55%), but the PPOA model did show a considerable drop (26.01%), further demonstrating the effect of the ITC and cost multiplier assumptions. In the Conservative Technology PPOA model, reductions from the 2040 to the 2050 outputs (23.79% reduction) were larger than those seen in the Moderate and Advanced Technology cases where costs remained relatively stable after the initial drop at 12.36% and 14.77% respectively. In the ATB model, price reductions also leveled out in this later period, though by a smaller degree: Conservative Technology scenario prices fell by 18.59% from 2040 to 2050 while in the Moderate Technology and Advanced Technology cases they fell by 8.75 and 12.37% respectively.

The most striking difference in cost trajectories was the effect of the expiration of the ITC in the PPOA model. In the Conservative Technology case, the average LCOE rose by 2.12% from 2035 to 2040 and then fell by 12.24% from 2040 to 2045 such that, overall, the LCOE fell by 10.38% over that 10-yr period. In the Advanced Technology case, LCOE rose by 6.72% from 2035 to 2040 and fell by 7.48% such that the overall decrease over that period was 1.26%. In the Moderate Technology case, LCOEs did not fully recover by 2045: Initially, they rose by 8.00% and fell by only 6.29%, resulting in an overall price increase of 1.2% from 2035 to 2045. This compared to 17.01%, 8.40%, and 11.70% overall reduction in LCOEs over the same period in the ATB model for the Conservative Technology, Moderate Technology, and Advanced Technology scenarios respectively.

Because of the size of Puerto Rico, transmission grid tie-lines are not as long as they typically are in CONUS but do add an important component to the overall costs of each model site. The average distance from site to the nearest substation was 6.24 km for the Less Land scenario and

5.77 km for the More Land scenario. This resulted in average LCOTs of 0.74$/MWh, $0.70/MWh, $0.67/MWh for the Conservative Technology, Moderate Technology, and Advanced Technology scenarios in the 2030 Less Land variation and 0.69$/MWh, 0.65$/MWh, and $0.63/MWh in the More Land scenario. Across all scenarios and model years, the LCOT ranged from $0.04/MWh in an Advanced Technology/More Land 2030 model run in Adjuntas to $2.39/MWh in a 2023 Advanced Technology/More Land run in Jayuya.

4.1.3.2.3 Supply Curve Results

Because of the inverse relationship between capacity and capital costs (see Figure 44), there was a strong inverse relationship between plant capacity and LCOE. This places a preference for fewer, larger plants in the capacity expansion model. The bulk of the modeled sites have less than about 50 MW of technical potential, which means most potential sites will have relatively high costs.

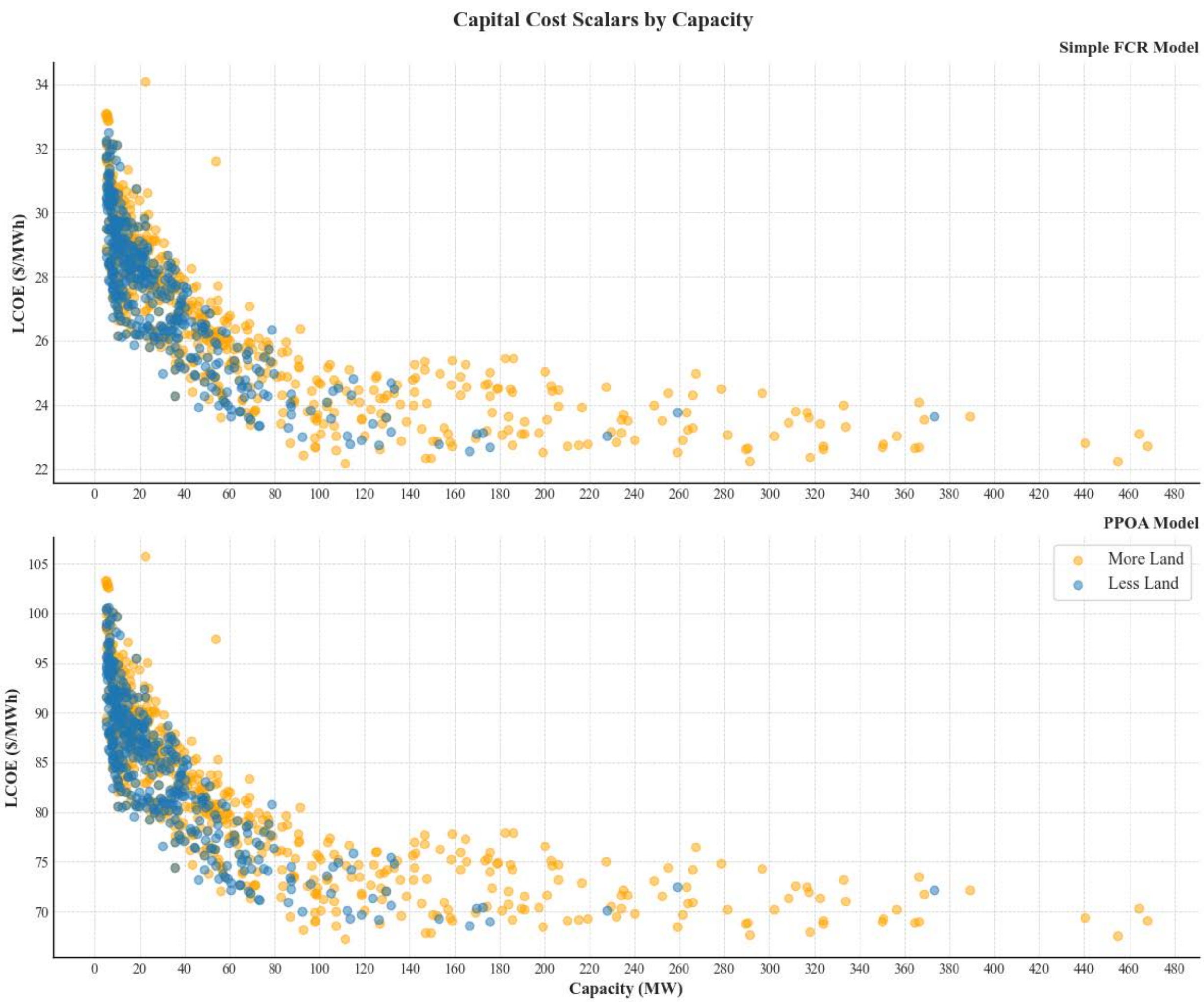

Figure 44. Total LCOE by plant capacity for the 2030 ATB Moderate Technology scenario

Cumulative capacity curves provide a way of displaying the aggregate amount of technical potential in a study area under a continuum of increasing costs. Figure 45 and Figure 46 were made by sorting the supply tables by LCOE (least expensive to most expensive) and calculating the cumulative sum of capacity for each site. This curve shows the total amount of capacity available under any cost threshold. Using the 2030 model year and the PPOA method for LCOE as the most representative scenario, the cumulative capacity graphs in the figures show there were 5.20 GW under $75/MWh in the Moderate Technology scenario and that threshold had to be set at $58.25/MWh before the technical potential was reduced to that amount in the Advanced Technology case. In all cases, the Conservative Technology scenario was significantly more expensive than either the Moderate Technology or Advanced Technology cases. In fact, the least expensive site in the Conservative Technology scenario was 115.49 $/MW, or 1.15 times more expensive than the most expensive site in the Moderate Technology scenario ($100.64/MWh). These figures also demonstrate the difference in scales for capacity estimates between techno-economic potential and market adoption, as the more expensive plants would not be considered economically viable.

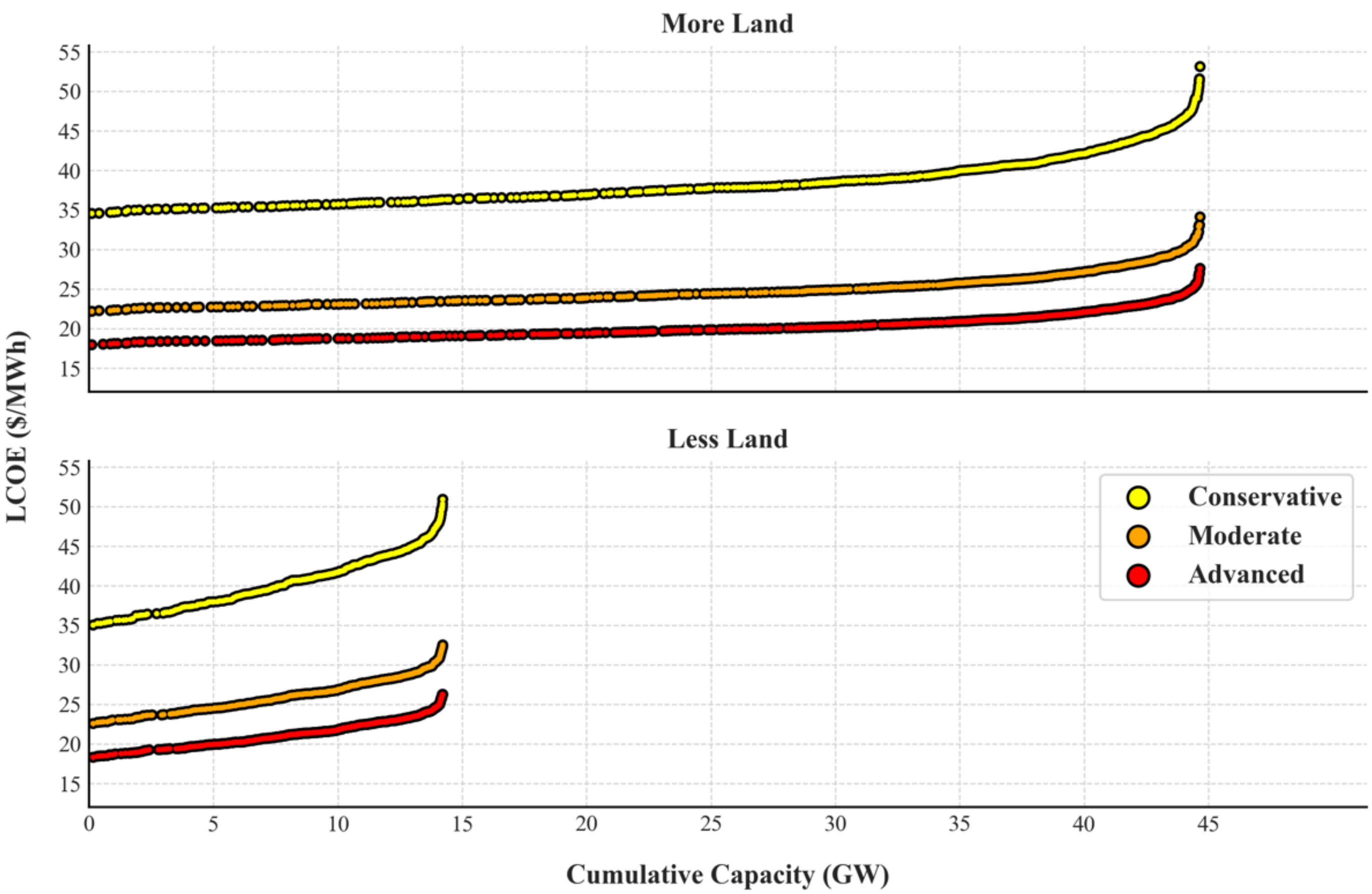

Figure 45. LCOE by cumulative capacity for the 2030 Moderate Technology scenario for both land access variations using the Simple FCR LCOE method

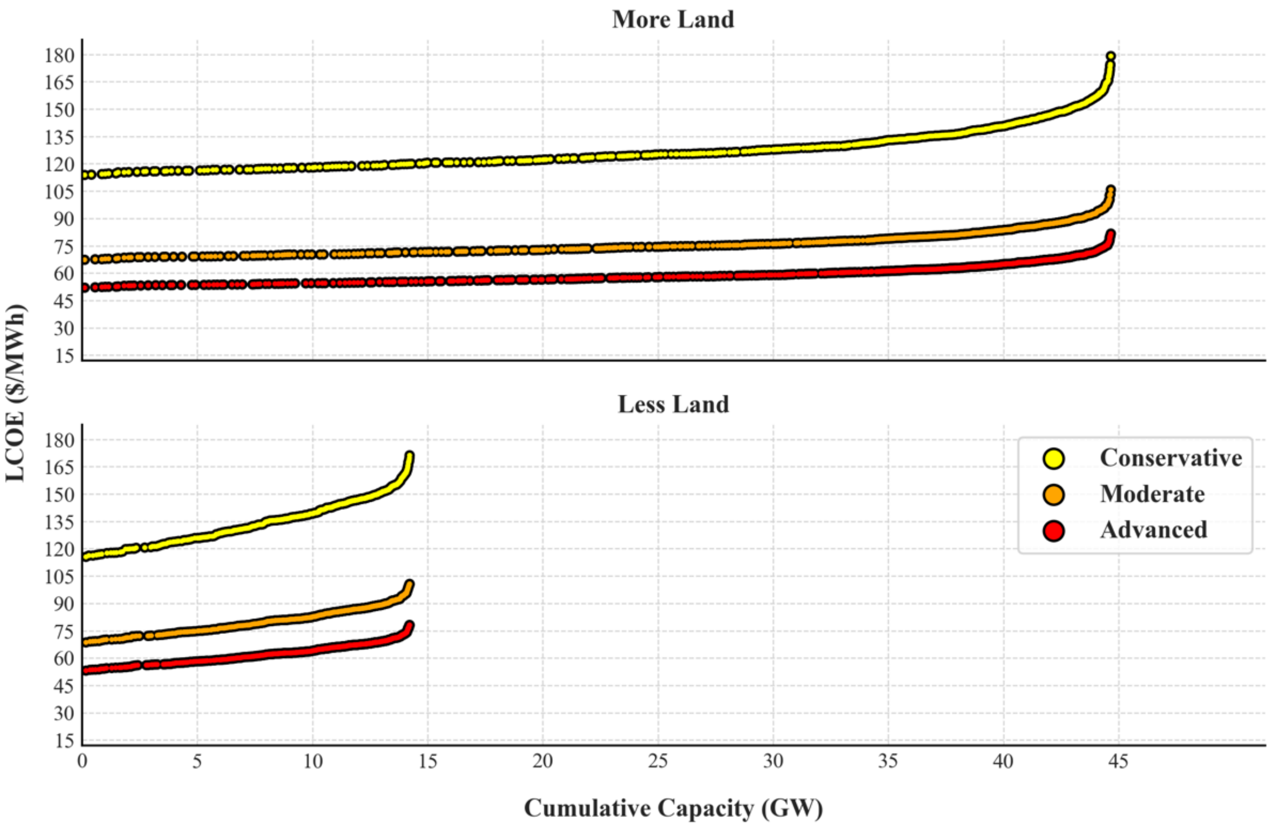

Figure 46. LCOE by cumulative capacity for the 2030 Moderate Technology scenario for both land variations using the PPOA model

The inverse capacity-LCOE relationship can also be seen in maps of these variables for individual model sites. Figure 47 shows the resulting capacities for all model sites in the 2030 Moderate Technology/Less Land variation. The results show major concentrations of medium-sized sites in the northwestern corner of the main island, several large-scale sites in Salinas, and small sites distributed across the periphery of all three islands. Maps of modeled LCOEs for the More Land and Less Land variations, however, show the exact inverse pattern due to economies of scale (Figure 48 and Figure 49).

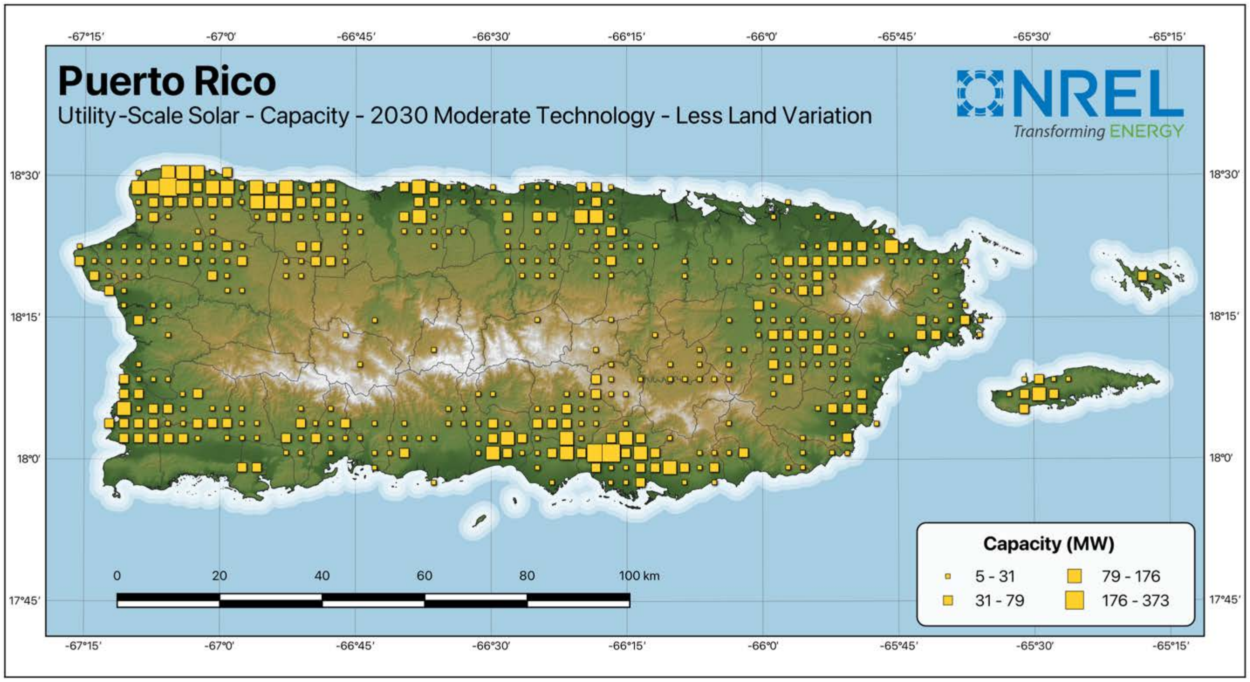

Figure 47. Distribution and magnitudes of capacity for individual model sites across Puerto Rico for the 2030 Moderate Technology/Less Land variation

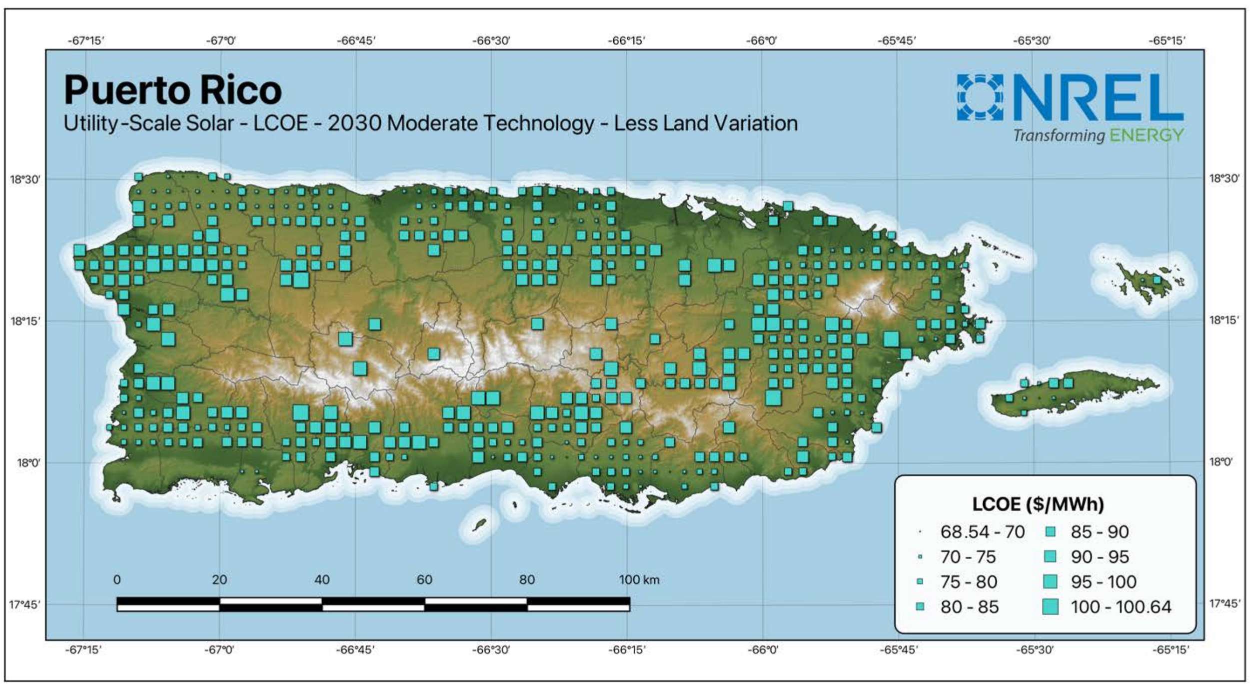

Figure 48. Distribution and magnitudes of LCOE for individual model sites across Puerto Rico for the 2030 Moderate Technology/Less Land variation

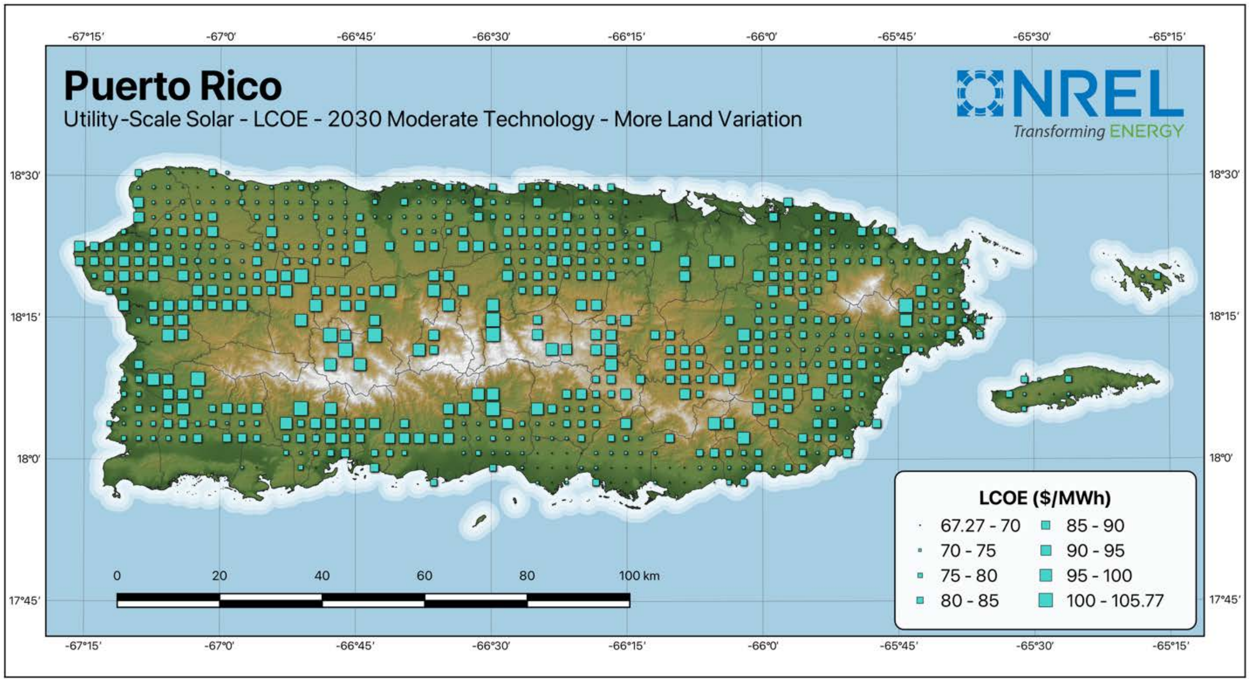

Figure 49. Distribution and magnitudes of LCOE for individual model sites across Puerto Rico for the 2030 Moderate Technology/More Land variation

However, the results of the model show a more complex relationship than that between capacity and costs. To further demonstrate the spatial effects of the interplay of the cost, capacity, and technology advancement components of the model, Figure 50 shows the number of sites and capacities under the 2030 Moderate Technology and Advanced Technology cases under different cost thresholds (Conservative Technology was excluded because no sites were under the highest cost threshold). Here, the model found there was 8.01 GW of capacity under $80/MWh, 5.20 GW under $75/MWh, and only 0.95 GW under $70/MWh. This latter amount of capacity was mainly distributed across four midsize plants in the northwestern-most corner of the main island in Aguadilla and Isabela municipalities. Notably, in this latter threshold, even the largest sites in Salinas were excluded despite the costs savings associated with economies of scale; this was because the CapEx multipliers were set to level out at 1.0 for 100-MW sites, which isolated the effect of resource quality for sites above that threshold. However, the Advanced Technology case maintained full capacity (14.22 GW) under the $80 threshold and lost only a marginal amount of capacity in the western-central region of the main island when the threshold reached $70/MWh (13.32 GW). Figure 50 shows a set of lower cost threshold maps for the 2050 scenario, demonstrating a downward shift in costs but also reflecting the lower rate of cost reductions after 2030 as seen in Figure 51. These maps demonstrate the potential for economically viable utility-scale PV in Puerto Rico heavily depends on the level of technology advancement reached by the target year for each goal and shows that the northwestern-most portion of the main island provides the most cost-effective combination of solar resource and land availability.

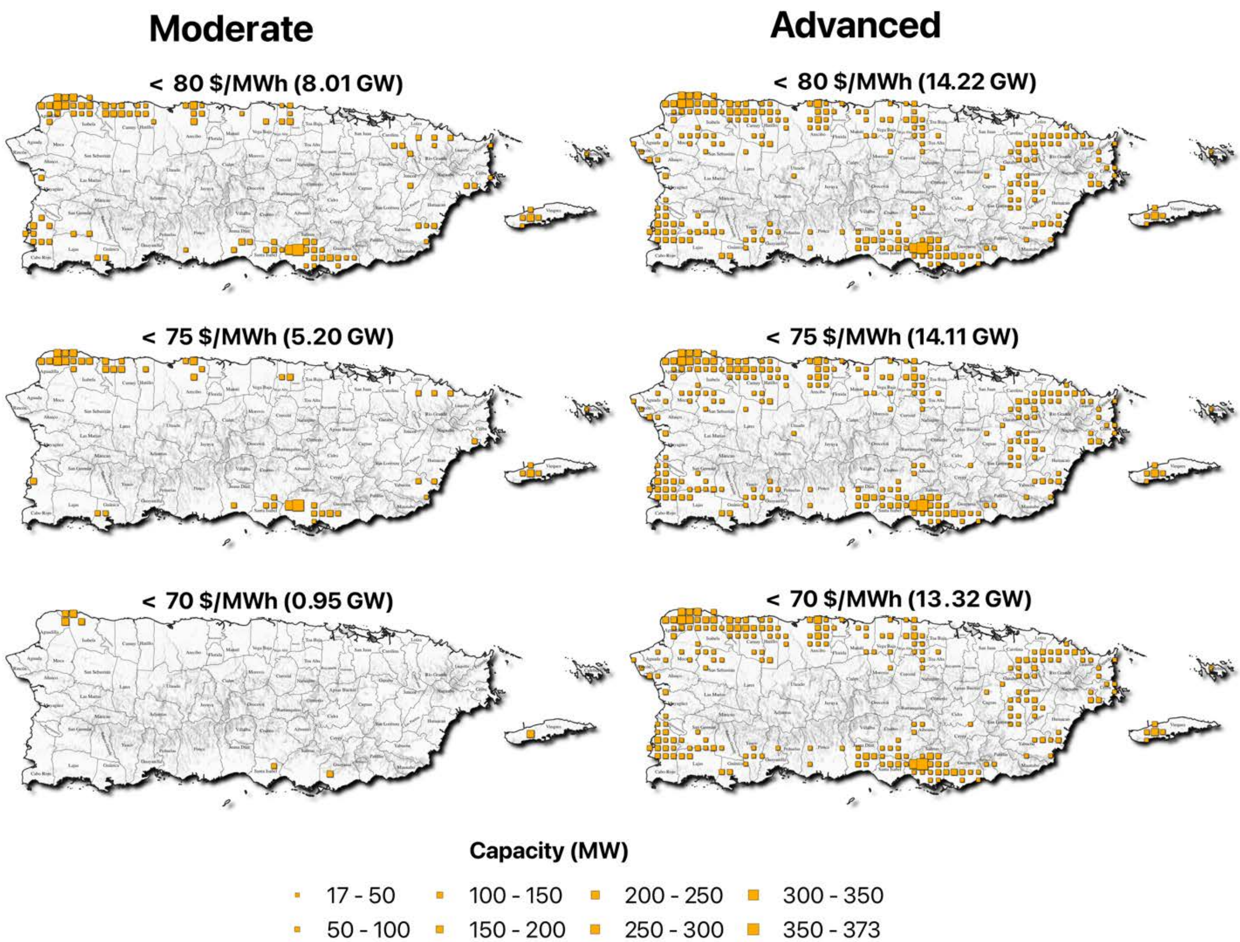

Figure 50. Remaining capacity under different cost thresholds for the 2030 Less Land, Moderate Technology, and Advanced Technology scenarios using the PPOA LCOE model

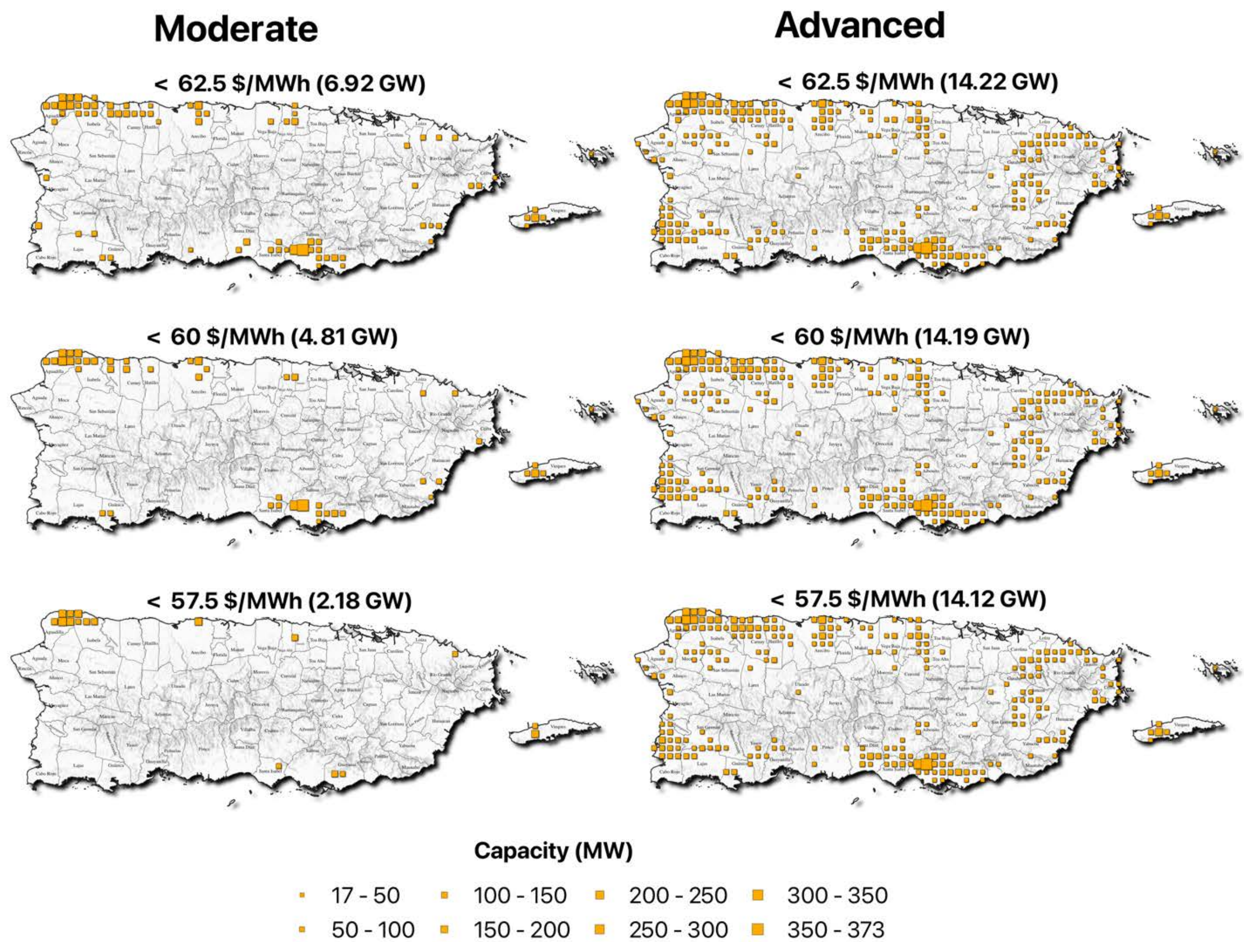

Figure 51. Remaining capacity under different cost thresholds for the 2050 Less Land, Moderate Technology, and Advanced Technology scenarios using the PPOA LCOE model

4.1.3.2.4 Summary Results

We found that while the Less Land variation provides sufficient developable area to meet annual load, the reduced land area is anticipated to result in the development of a greater number of smaller solar PV and land-based wind plants that are more dispersed across Puerto Rico, while the More Land scenario is more likely to result in larger but fewer plants. Due to the reduced economies of scale and increase in required infrastructure (e.g., access roads, interconnections, etc.) the costs associated with deployment under the Less Land scenario are higher on average than the More Land scenario across all modeled years and technology scenarios (Table 10). In summary, more utility-scale solar PV capacity is available for each site at a lower levelized cost of electricity (LCOE) on average in scenarios where more land is available for development than less land ($75.09/MWh PPOA LCOE and 44.67 GW for More Land and $79.02/MWh and 14.22 GW for Less Land in 2030 in the Moderate Technology scenario).

Table 15. Model Output Summary

Technology Scenario	Land Access	Model Year	Capacity (GW)	Area (km^2)	AEP (TWh)	PPOA LCOE ($/MWh)	ATB LCOE ($/MWh)
Conservative	Less Land	2023	14.22	203.14	22.59	179.83	40.58
Conservative	Less Land	2030	14.22	203.14	22.59	133.05	39.95
Conservative	Less Land	2035	14.22	203.14	23.26	107.38	36.82
Conservative	Less Land	2040	14.22	203.14	23.93	109.65	33.69
Conservative	Less Land	2045	14.22	203.14	24.60	96.23	30.56
Conservative	Less Land	2050	14.22	203.14	25.27	83.56	27.43
Conservative	More Land	2023	44.67	638.09	70.91	170.63	38.67
Conservative	More Land	2030	44.67	638.09	70.91	126.27	38.07
Conservative	More Land	2035	44.67	638.09	73.01	101.78	35.09
Conservative	More Land	2040	44.67	638.09	75.12	103.83	32.12
Conservative	More Land	2045	44.67	638.09	77.22	91.15	29.15
Conservative	More Land	2050	44.67	638.09	79.32	79.17	26.17
Moderate	Less Land	2023	14.22	203.14	23.05	163.75	37.04
Moderate	Less Land	2030	14.22	203.14	25.80	79.02	25.75
Moderate	Less Land	2035	14.22	203.14	26.27	67.07	24.71
Moderate	Less Land	2040	14.22	203.14	26.74	72.44	23.67
Moderate	Less Land	2045	14.22	203.14	27.20	67.88	22.63
Moderate	Less Land	2050	14.22	203.14	27.67	63.49	21.6
Moderate	More Land	2023	44.67	638.09	72.37	155.41	35.3
Moderate	More Land	2030	44.67	638.09	81.00	75.09	24.57
Moderate	More Land	2035	44.67	638.09	82.46	63.65	23.58
Moderate	More Land	2040	44.67	638.09	83.93	68.65	22.59
Moderate	More Land	2045	44.67	638.09	85.40	64.33	21.61
Moderate	More Land	2050	44.67	638.09	86.87	60.18	20.62
Advanced	Less Land	2023	14.22	203.14	23.17	158.61	35.88
Advanced	Less Land	2030	14.22	203.14	27.81	61.23	20.9
Advanced	Less Land	2035	14.22	203.14	28.11	51.49	19.74
Advanced	Less Land	2040	14.22	203.14	28.41	54.94	18.58
Advanced	Less Land	2045	14.22	203.14	28.72	50.84	17.43
Advanced	Less Land	2050	14.22	203.14	29.02	46.83	16.28
Advanced	More Land	2023	44.67	638.09	72.73	150.53	34.2
Advanced	More Land	2030	44.67	638.09	87.30	58.22	19.96

Technology Scenario	Land Access	Model Year	Capacity (GW)	Area (km²)	AEP (TWh)	PPOA LCOE ($/MWh)	ATB LCOE ($/MWh)
Advanced	More Land	2035	44.67	638.09	88.25	48.88	18.85
Advanced	More Land	2040	44.67	638.09	89.20	52.10	17.74
Advanced	More Land	2045	44.67	638.09	90.15	48.21	16.65
Advanced	More Land	2050	44.67	638.09	91.09	44.41	15.56

4.2 Wind

4.2.1 Wind Resource Assessment

We used a numerical weather prediction model to generate the 20 years of wind resource data sets for Puerto Rico. Specifically, we used the Weather Research and Forecasting (WRF) model, Version 4.3 (Skamarock et al. 2019) to model wind speed and direction at different hub heights and other atmospheric variables needed for wind energy modeling. The research steps in developing the high-resolution wind data sets based on WRF model were to:

- Develop a WRF model configuration using two nested domains (9 km and 3 km) for Puerto Rico
- Test various choices within WRF to identify the most accurate combination of WRF physics modules for generating wind resource data
- Assess modeled wind data using observations
- Determine the best performing WRF setup from the model evaluation
- Generate 20 years of data (2001–2020) from the WRF model and make the data publicly available through NREL to support wind energy development considerations for PR100.

We used the ECMWF Reanalysis Version 5 (ERA5) data (0.25°×0.25°; hourly interval) (Hersbach et al. 2020) as the input to the WRF model. The ERA5 is a global reanalysis data set that provides hourly estimates of oceanic, land, and atmospheric variables. We selected ERA5 for initial and boundary conditions of the WRF model because previous studies (de Assis Tavares et al. 2020; Gualtieri 2022) confirmed ERA5 is a sufficiently reliable reanalysis product and because it is widely used for wind resource assessment.

We selected all settings and physics parameterizations based on Optis et al. (2020) except the planetary boundary layer (PBL) and surface layer parameterizations. Comprehensive details about the WRF configurations used are summarized by Sengupta et al. (2022). We performed monthly based WRF simulations in parallel to effectively use high-performance computing resources. In a subsequent postprocessing phase, we stitched together 12 sets of 1-month simulations to obtain a year's worth of data. To keep consistent levels of accuracy when conducting the monthly simulations, we applied a spectral nudging technique with nudging parameters suitable for Puerto Rico. We postprocessed the WRF outputs to include wind profile and other atmospheric variables with a downstream model-friendly format. The 20-yr (2001–2020) wind resource data have been made publicly accessible through NREL and have served as the basis for examining the wind energy costs for Puerto Rico (Duffy et al. 2022).

We compared 11 WRF simulations focused on using different PBL parameterizations against observations obtained from the National Data Buoy Center[84] to choose a final WRF physics combination. To implement a fair comparison of modeled and observed wind speeds, we vertically interpolated the WRF's 10-m wind speed to the anemometer heights of seven stations, available from the National Data Buoy Center database for 2019. Figure 52 shows the diurnal cycle of statistical metrics and the bulk statistics computed with all available modeled-observed data of surface wind for the seven National Data Buoy Center sites for Puerto Rico (the bulk statistics were calculated only for 3.1 < wind speed ≤ 8.2 m/s).

The WRF model using 11 PBL schemes (E01–E11) overestimates surface wind speeds with positive mean bias error (MBE) across most hours. Individual members of E01–E11 exhibit different error and bias patterns during daytime and nighttime because the PBL parameterizations model wind speed with different algorithms within the WRF model. The bulk statistics shown in Figure 52 evaluate modeled wind speeds in the range of cut-in and rated wind speed (3.1 < wind speed ≤ 8.2 m/s). A Shin-Hong "scale-aware" PBL scheme (Shin and Hong 2015) (E09) shows better overall performance than all other PBL schemes (e.g., the Shin-Hong scheme is the only scheme that satisfied RMSE < 1.5 m/s, MAE < 1.2 m/s, and MBE < 0.1 m/s); therefore, we selected and used the Shin-Hong PBL within the WRF model to generate the final wind resource data sets covering 2001–2020.

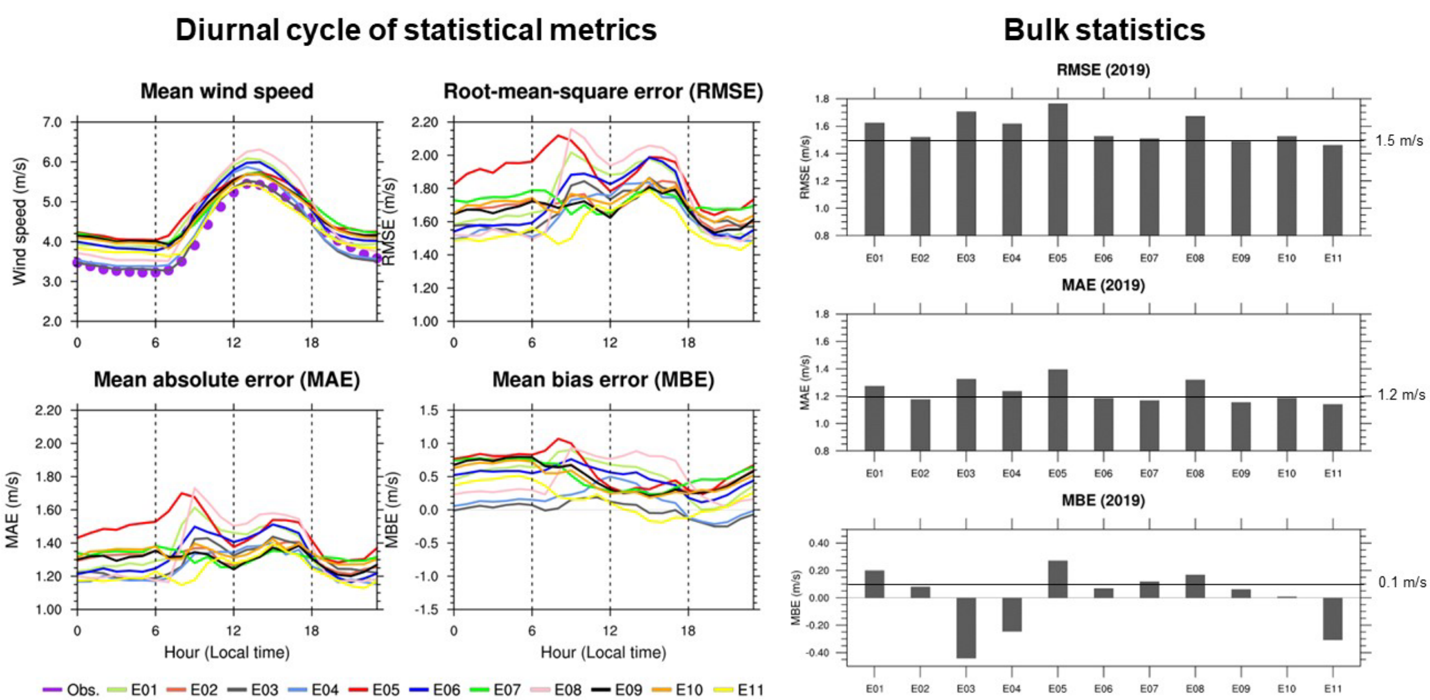

Figure 52. Diurnal cycle of statistical metrics and bulk statistics calculated for 2019

Puerto Rico is well known to be dominated by prevailing northeasterly trade winds (Jury, Chiao, and Harmsen 2009). As shown in Figure 53, the modeled data correctly represented the wind climatology of Puerto Rico: Over land, the mean wind speed depends heavily on topography, and wind speeds to the north and south of the archipelago are notably higher. A pocket of lower wind

[84] "National Data Buoy Center," NOAA, https://www.ndbc.noaa.gov/.

speeds west (leeward) of the archipelago is also represented by the WRF model. The highest long-term offshore wind speeds are found in southern parts of the archipelago. More scientific analysis results are described by Yang et al. (2023).

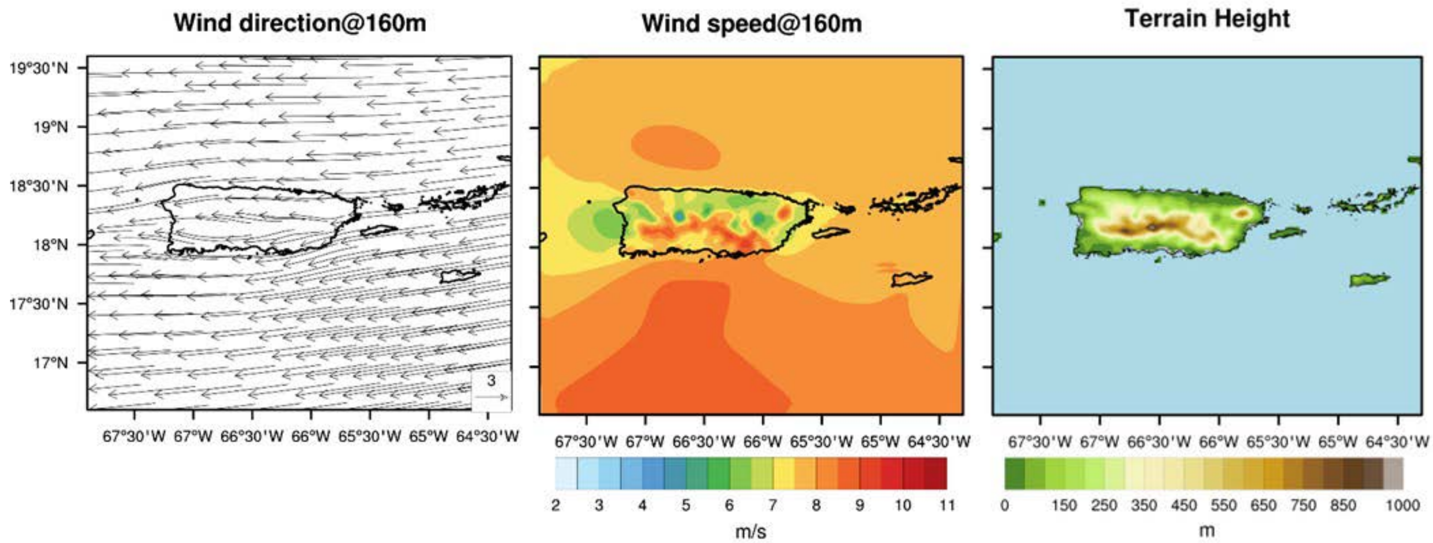

Figure 53. 2D maps of 20-yr mean wind speeds, wind direction at 160 m, and terrain height for Puerto Rico

To analyze the wind resource characteristics in detail, we selected four offshore wind sites and four land-based wind sites. Figure 54 shows the 20-yr mean wind profiles modeled from the WRF for those sites. The offshore wind speed marginally increased for all four sites. The rate of increase in wind speed was considerably reduced above 40 m. The land-based wind speed increased more rapidly with height than offshore wind because the greater surface roughness of land results in higher resistance to the wind flow.

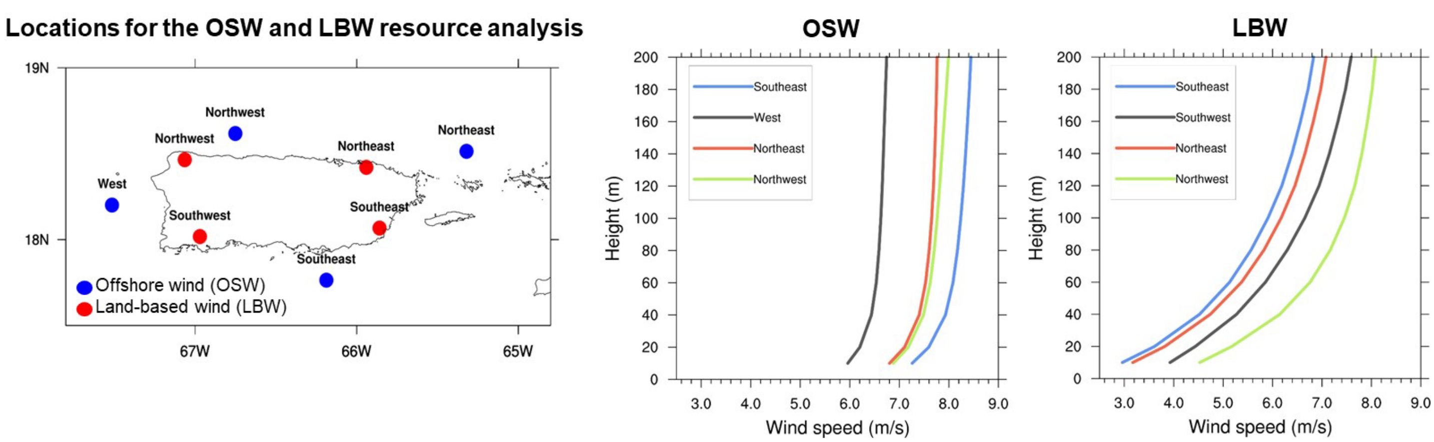

Figure 54. Locations of offshore wind and land-based wind sites and 20-yr mean wind profiles

OSW is offshore wind, and LBW is land-based wind.

For the offshore wind and land-based wind sites, we also analyzed the climatological fluctuations in wind captured from the modeled wind on monthly and annual scales. The monthly and yearly mean wind speeds at 160 m were calculated over 20 years for Puerto Rico (Figure 55). The offshore wind results revealed that the wind 160-m wind speed increased in the early rainy season (May–July) and peaked in July for most offshore wind sites. The offshore wind sites showed lower wind speeds in the late rainy season (August–November) than in the other seasons. Except for the southwestern site, the 160-m wind speed for the land-based wind locations exhibited patterns similar to the monthly variation in the offshore wind sites. The yearly mean wind speed shown in Figure 55 revealed no obvious increasing or decreasing trends over 20 years for offshore wind and land-based wind sites.

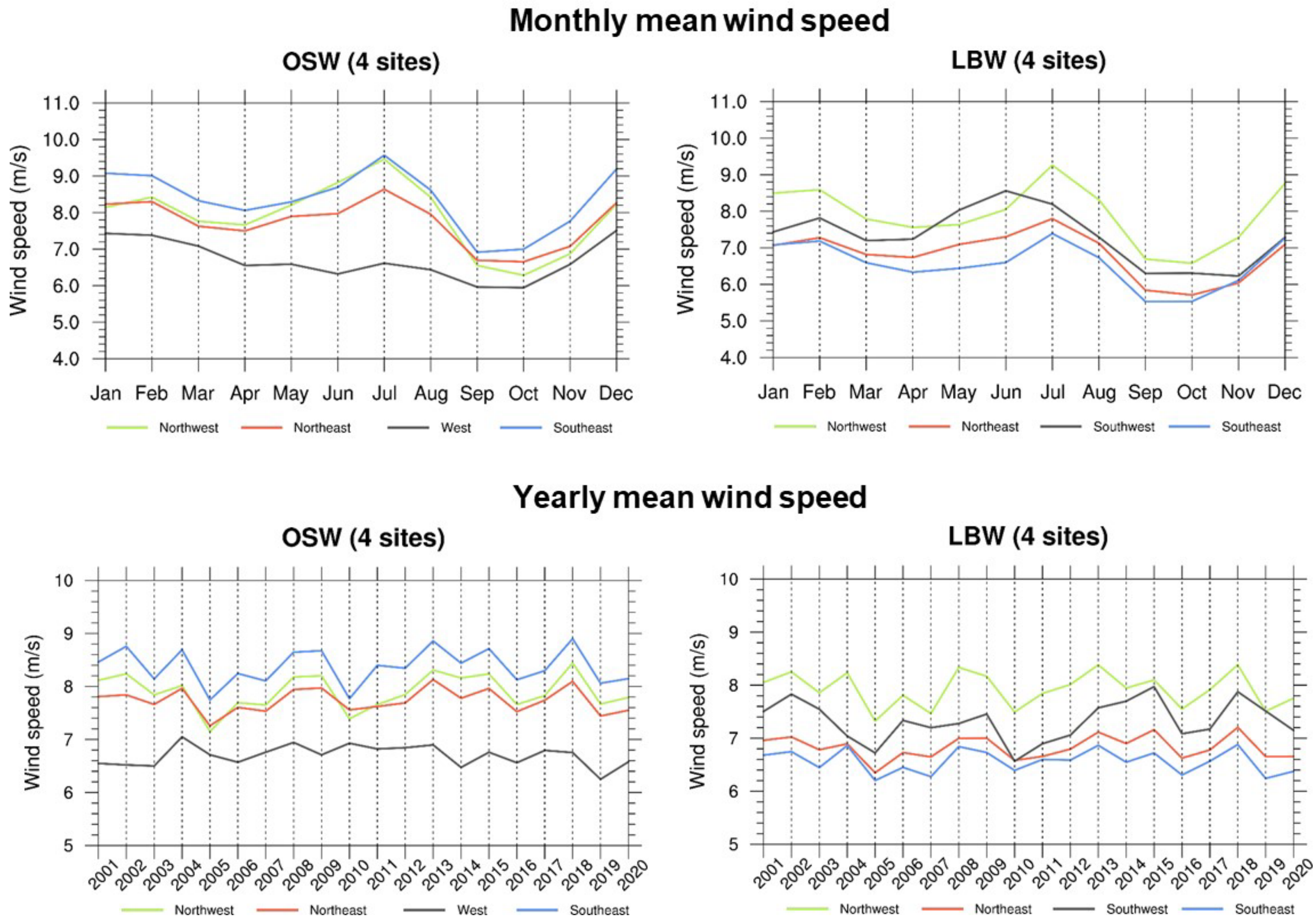

Figure 55. Monthly and annual mean wind speeds for offshore wind and land-based wind sites

The PR100 project team loaded the 20 years of wind resource data (5-min and hourly temporal resolution) to the Highly Scalable Data Service (HSDS). Users can refer a GitHub repository with set-up guidance for using a Jupyter notebook to access the HSDS data.[85] Users need to clone the repository to their computers and follow the instructions starting at How to Use. Once users get a sample notebook to work with a HSDS data set, they can modify it to work with their own data set. If users install h5pyd[86] and execute hsconfigure, they should be able to test the connection by running the hsinfo. And then, users can check the /nrel/directory by executing hsls. For example, users can run hsls /nrel/ to see what is in the directory.

[85] https://github.com/NREL/hsds-examples
[86] As shown in the instructions available at https://github.com/NREL/hsds-examples

The wind data sets for Puerto Rico are in:

- Hourly data (puerto_rico_wind_hourly_yyyy.h5): /nrel/wtk/pr100/hourly/
- 5-min data (puerto_rico_wind_5min_yyyy.h5): /nrel/wtk/pr100/5min/

4.2.2 Wind Technical Potential

In this analysis, we assessed wind energy costs and technical potential in Puerto Rico to provide stakeholders with a better understanding of wind resources and guide future planning processes (Duffy et al. 2022). We used the high-resolution wind resource data set developed by Sengupta et al. (2022) and the relevant wind energy techno-economic analysis tools (e.g., NREL's reV model) to evaluate costs, performance, and technology options. First, we made efforts to modify the cost models to reflect Puerto Rico's unique features and costs. And then we defined wind energy technology pathways to project costs from 2023 through 2035 for land-based wind and from 2030 through 2035 for offshore wind. Details about the wind technical potential for Puerto Rico are described in (Duffy et al. 2022).

We have not examined distributed wind technical potential. In Section 15, distributed wind is defined as any wind turbine connected to the distribution grid (versus the transmission grid that most utility-scale wind farms are connected to). Distributed wind can range from small turbines in single or a few turbines for behind the meter applications to full-scale (1+ MW) turbines but connected to the distribution feeder. Distributed wind is identified as an emerging technology that could impact Puerto Rico power generation on the path to 100% renewable energy. Some of the excluded areas (such as urban environments) might support distributed wind deployments. Therefore, the overall land-based wind technical potential may evolve to include more direct analysis of distributed wind potential.

The key findings from this modeling work are summarized as follows (see Table 16, page 105).

Table 16. Summary of Wind Costs and Energy Production for Land-Based Wind and Offshore Wind

Technology	Land Use Variation	Year	Mean LCOE ($/MWh)	Minimum LCOE ($/MWh)	Maximum LCOE ($/MWh)	Mean NCF (%)
Land-based wind	Less Land	2023	$92	$51	$292	26%
	Less Land	2030	$85	$47	$268	26%
	Less Land	2035	$65	$41	$187	42%
	More Land	2023	$84	$45	$244	26%
	More Land	2030	$76	$41	$223	26%
	More Land	2035	$58	$35	$156	42%
Offshore wind	N/A	2030	$137	$82	$156	36%
	N/A	2035	$118	$74	$130	38%

4.2.2.1 Levelized Cost of Energy (LCOE)

Land-Based Wind: The expected LCOE for the Less Land variation in 2023 ranges from approximately $51/megawatt-hour (MWh) to $292/MWh (5.8 cents/kilowatt-hour [kWh] to 29.2 cents/kWh) with a mean of $92/MWh. By 2035, the LCOE values decline to a range of $41/MWh–$187/MWh with a mean of $65/MWh.

Under the More Land variation, expected LCOE in 2023 ranges from approximately $45/MWh to $244/MWh with a mean of $84/MWh. By 2035, the LCOE ranges from $35/MWh to $156/MWh with a mean of $58/MWh.

The LCOE maps for land-based wind energy in 2030 are presented for the Less Land variation (Figure 56) and the More Land variation (Figure 57).

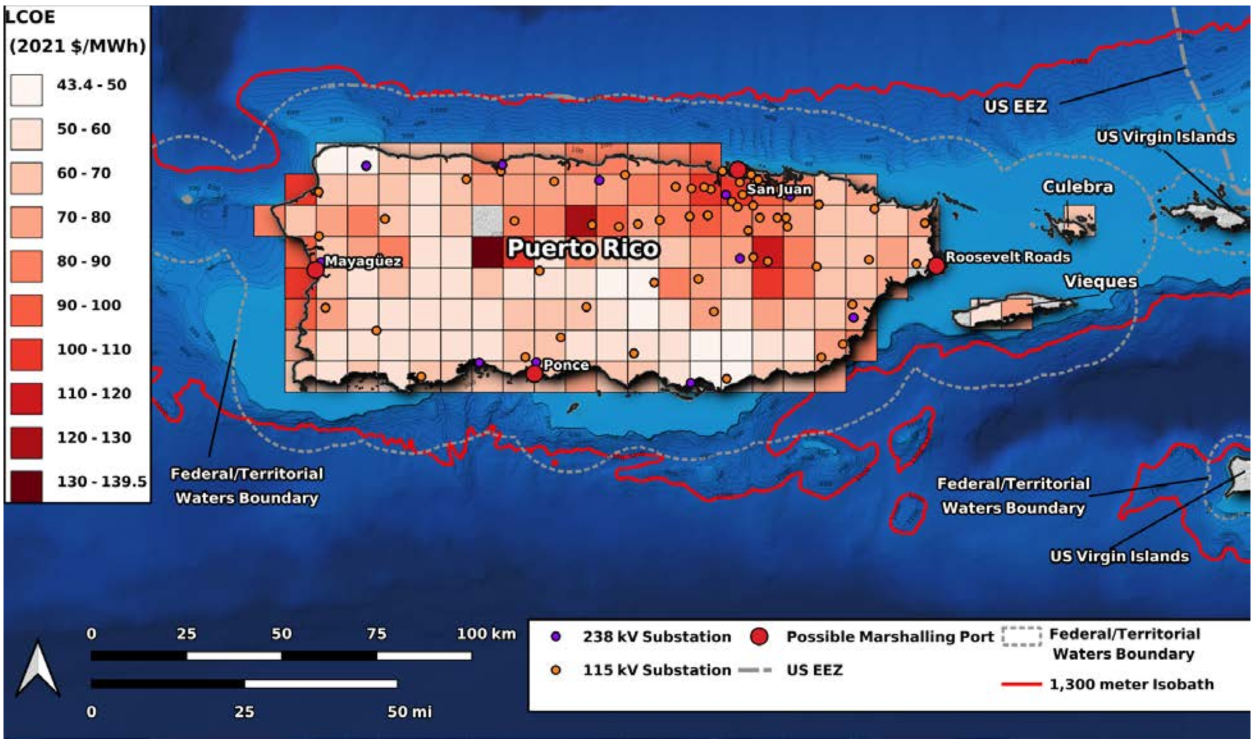

Figure 56. LCOE for land-based wind in 2035

Source: Duffy et al. (2022)

Offshore Wind: Expected LCOE ranges from approximately $82/MWh–$414/MWh in 2030 with a mean of $137/MWh and decline to $74/MWh–$350/MWh by 2035 with a mean of $118/MWh. The LCOE map for offshore wind energy in 2030 is presented in Figure 57.

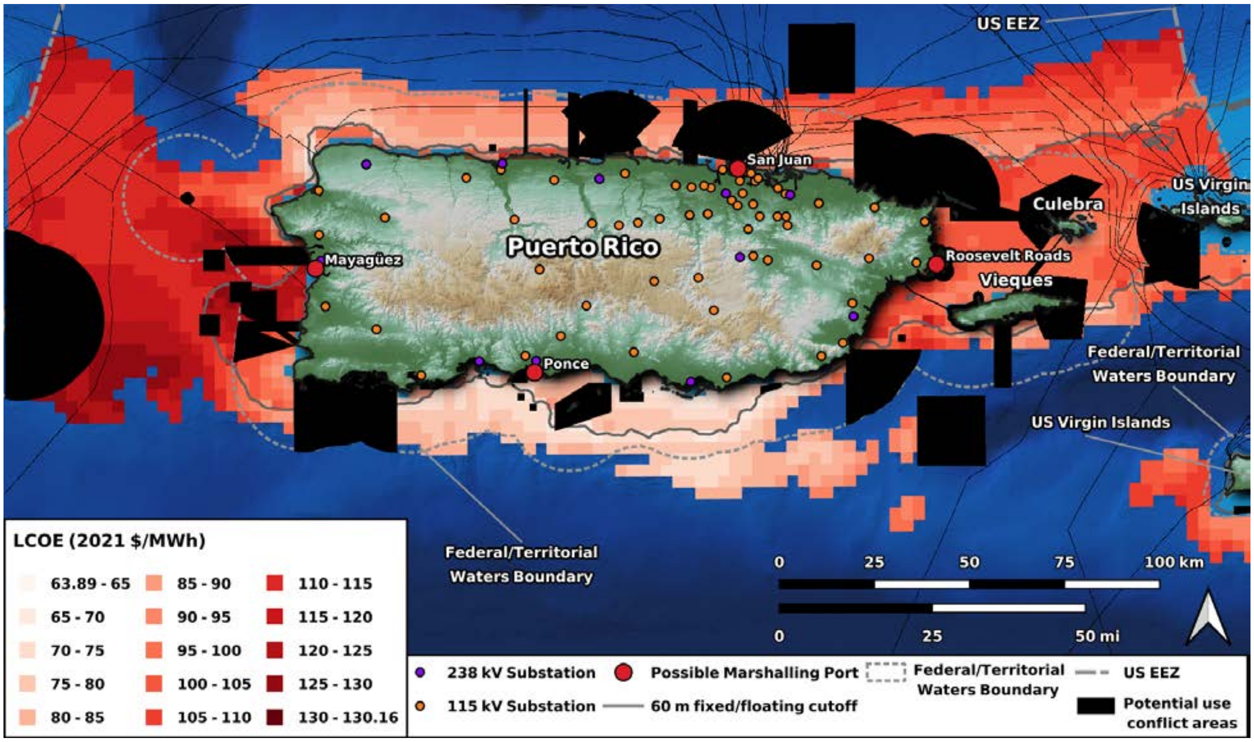

Figure 57. LCOE for offshore wind in 2035 (potential use conflict areas highlighted in black)

Source: Duffy et al. (2022)

4.2.2.1 Net Capacity Factor (NCF)

Land-Based Wind: We found that by 2035, NCF values for land-based projects in the Less Land variation range from 0.16 to 0.65, with an average of 0.42. The maps of expected 2030 wind plant AEP expressed in terms of NCF for land-based wind are presented in Figure 58 and Figure 59.

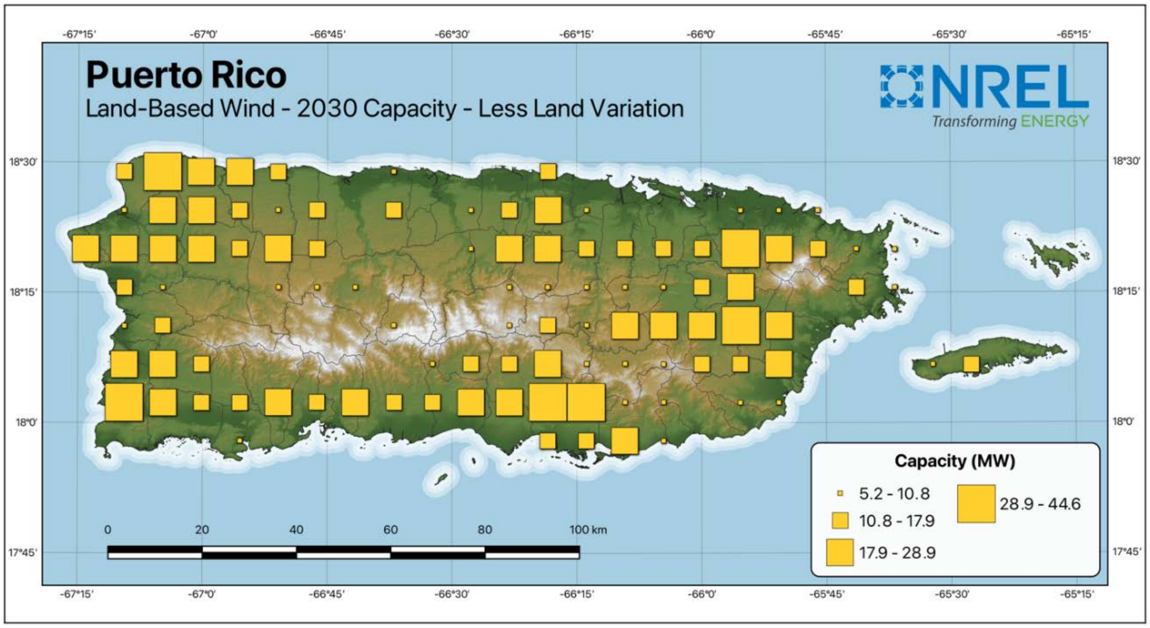

Figure 58. Net capacity factors for land-based wind in the Less Land variation in 2030

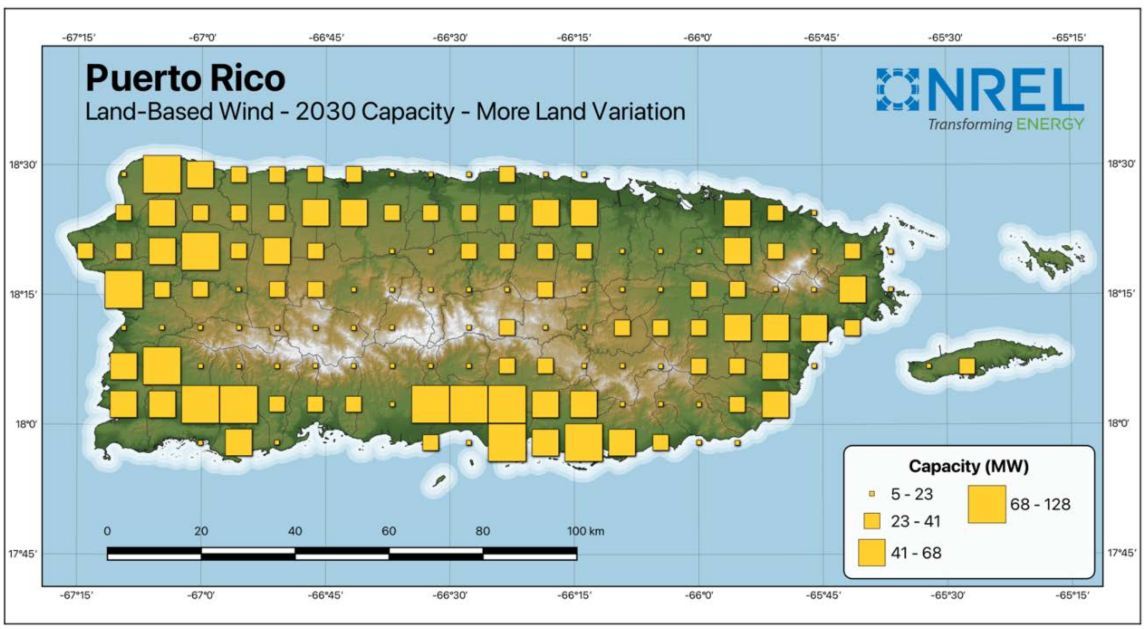

Figure 59. Net capacity factors for land-based wind in the More Land variation in 2030

Offshore Wind: As the offshore wind resource is stronger, the lower specific-power ratings (ratio of rotor swept area to generator rating) of the land-based machines assumed for 2035 help capture more energy at more frequent low wind speeds. NCF values for offshore wind projects range from 0.27 to 0.48, with an average of 0.38. The map of expected 2030 wind plant AEP expressed in terms of NCF for offshore wind is presented in Figure 60.

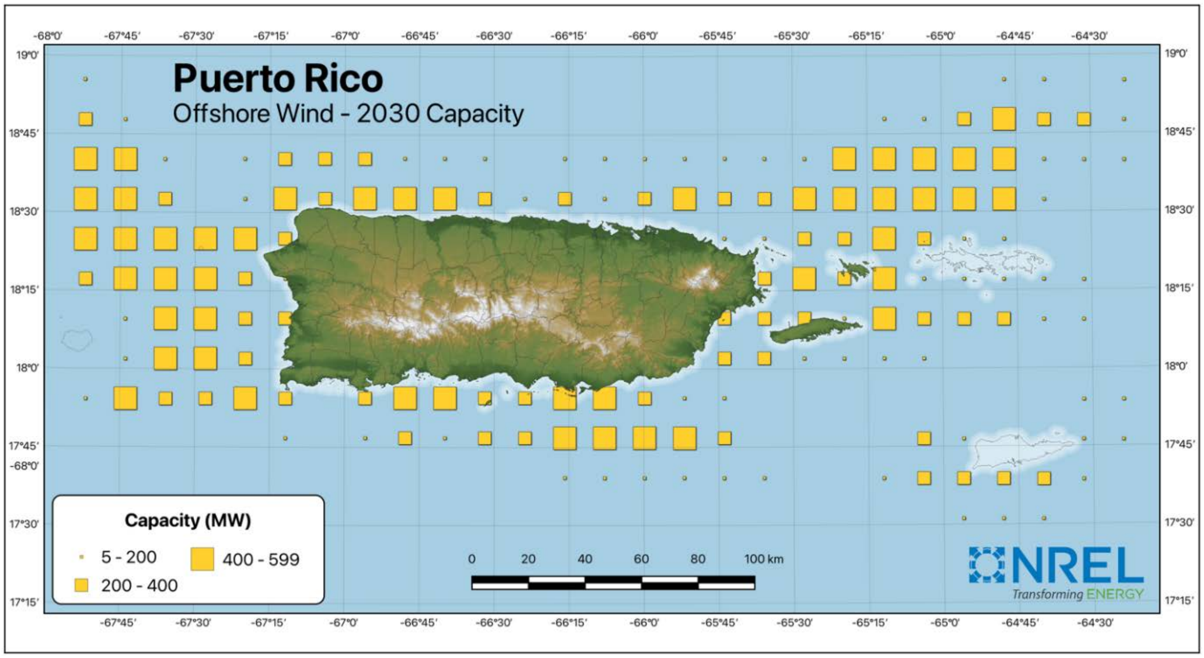

Figure 60. Net capacity factors for offshore wind in 2030

4.2.3 Results

For land-based utility-scale wind, the Less Land variation resulted in 537 km^2 of developable area (Figure 61). This result translates to about 1,610 MW_{AC} of capacity with an assumption of 3 MW_{AC}/km^2. The More Land variation resulted in 1,533 km^2 of available land (Figure 62). The More Land variation translates to approximately 4,600 MW_{AC} again assuming 3 MW_{AC}/km^2. The total assessed land area is 8,940 km^2, so these scenarios identify 6.0% and 17.2% of the total area as developable in the Less Land and More Land variations respectively.

For offshore wind, the total technical potential was determined to be 46.85 GW (using a capacity density assumption of 3 MW/km^2) with an estimated total developable area of 15,617 km^2 (Duffy et al. 2022). See Figure 63.

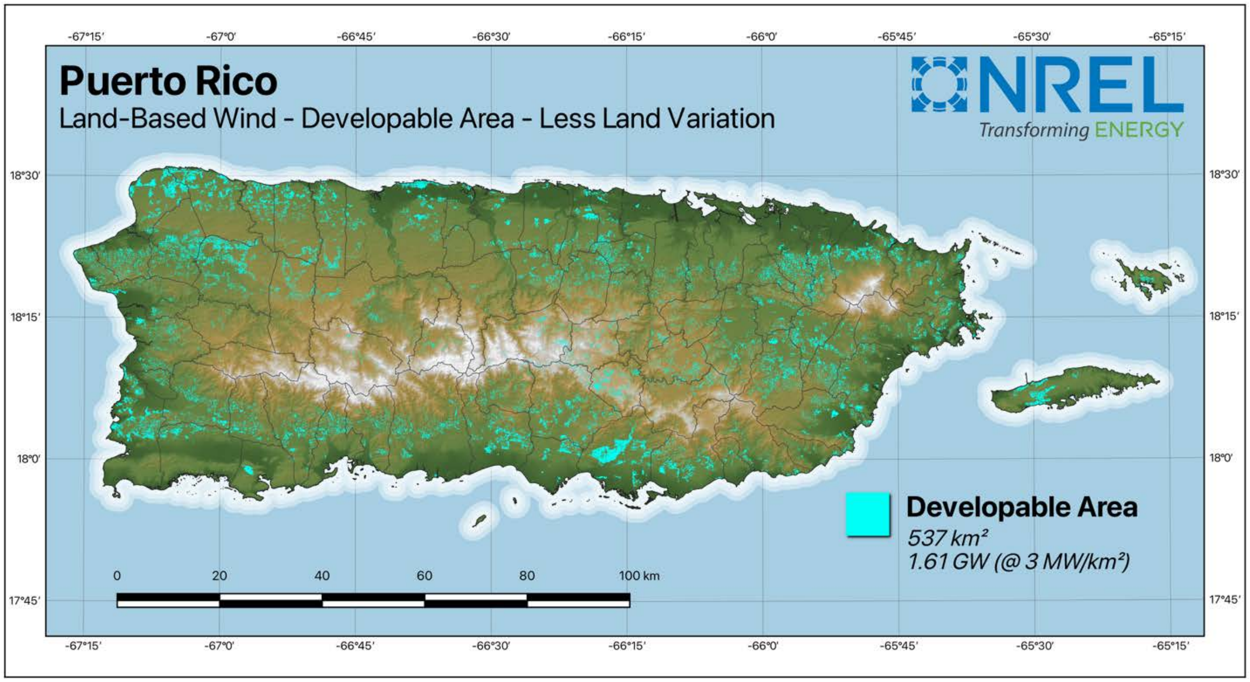

Figure 61. Developable area for land-based utility-scale wind in the Less Land variation

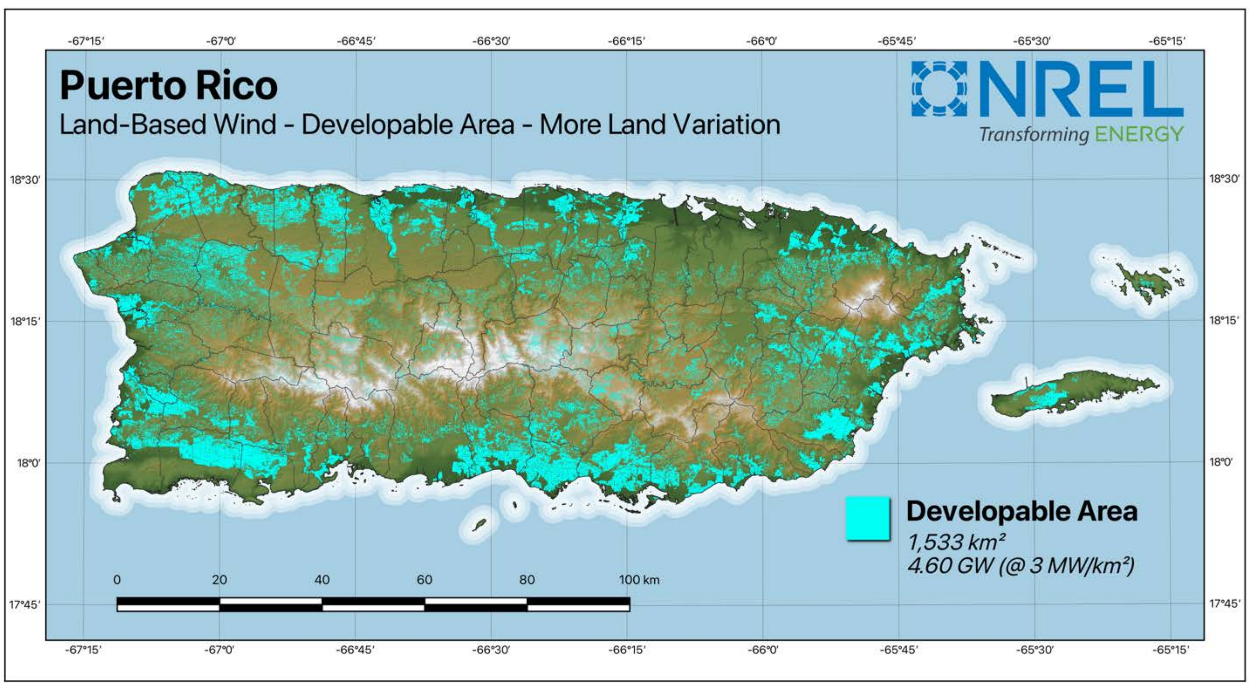

Figure 62. Developable area for land-based utility-scale wind in the More Land variation

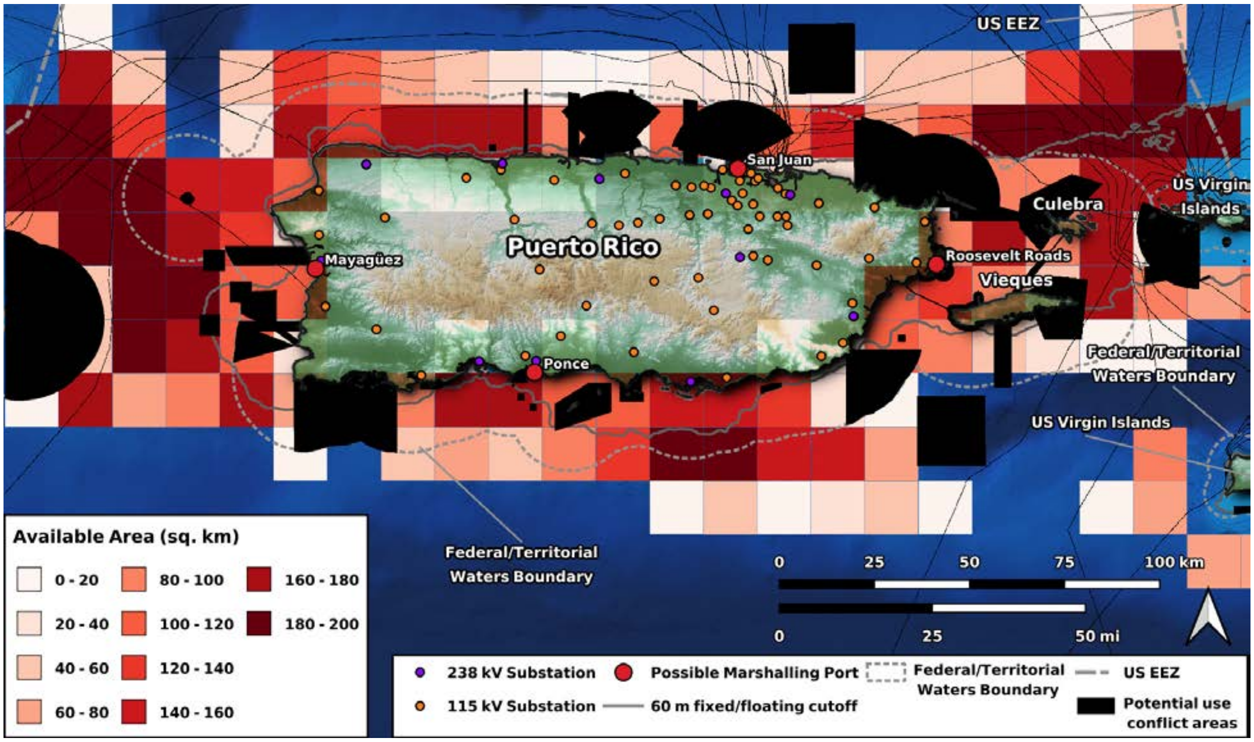

Figure 63. Available area after accounting for the 1,300-m technology depth cutoff and potential use conflict areas

Each grid cell represents 200 km^2. With a capacity density of 3 MW/km^2, a grid cell with 200 km^2 of available area could fit a 600-MW plant. Some of the available area in the federal waters off the coast of the U.S. Virgin Islands is not pictured here.

Source: Duffy et al. (2022)

4.3 Hydropower

4.3.1 Refurbishment of Existing Systems

In 2021, Black & Veatch conducted a study for PREPA to assess the existing hydropower infrastructure in Puerto Rico (PREB 2021b), with the objective to determine the feasibility of achieving the following primary goals with the refurbishments:

- Increase the generation production from its current capacity factor (approximately 0.06 over the last 3 years) to a goal capacity factor of 0.28. This includes improvements to the facilities and modifications to the reservoir operational curves through water availability forecasting.
- Evaluate the potential to increase the hydroelectric capacity at these facilities by means of improvements to their current capacities, or above their current capacities. Identify the estimated cost and time required to achieve this goal.
- Evaluate the units to determine their ability to automatically respond to frequency variation events on the electrical system. Identify recommendations for governor upgrades or other modifications to improve unit responsiveness.
- Evaluate the potential for control of all units from the PREPA Energy Control Center at Monacillo, San Juan (currently only Yauco 1 and Yauco 2 have this capability). Identify requirements to provide remote operation for each facility.

4.3.2 Non-Powered Dams

To assess the opportunity for hydropower growth in Puerto Rico, a dam inventory was created from the U.S. Army Corps of Engineer's National Inventory of Dams (NID) and was supplemented from additional dam information collected from relevant stakeholders. A total of 39 dams were identified in Puerto Rico. Based on independent verification, there are 20 hydropower dams and 19 non-powered dams (NPDs; defined as "dams that do not have any electricity generation equipment installed"[87]).

The hydropower expansion potential in Puerto Rico was analyzed by Oak Ridge National Laboratory (ORNL) and focused on NPDs, which represent both critical infrastructure (DeNeale et al. 2022; DeNeale et al. 2019; Hansen et al. 2021) and renewable energy development opportunities (Hadjerioua et al. 2012).

Hydropower potential assessment at NPD locations requires reliable streamflow and hydraulic head data to estimate power potential, energy generation, and costs. Much of the location data available required manually matching the NID dam point features to locations of dams visible in satellite imagery or described on basemaps such as OpenStreetMap and coincident with flowlines in the National Hydrography Dataset (NHD). A comparison of NID-reported coordinates and corrected locations reveals a median difference of 0.27km (maximum difference = 33.5 km).

Since most of the dam locations in Puerto Rico are ungauged, streamflow estimates were derived using the Variable Infiltration Capacity (VIC) – Routing Application for Parallel Computation of Discharge (RAPID) hydrologic modeling framework. The framework enables the production of streamflow estimates through the entire NHDPlusV2 river network in Puerto Rico. The streamflow estimates at NPD locations were utilized to conduct hydropower potential assessment.

Several input data sets such as meteorologic forcings, elevation, land cover, soil feature, and vegetation are required for the VIC–RAPID modeling framework. The high-resolution global soil and vegetation parameters developed by Schaperow et al. (2021) at 1/16˚ (~6 km) form the basis for VIC modeling. The Daymet V4 (Thornton et al., 2016; 2021) was used as a meteorological forcing, that has been available from 1950 to the present at a daily scale and 1 km spatial resolution. Streamflow observations at the U.S. Geologic Survey (USGS)-monitored stream gauges (USGS 2021) were used to calibrate and validate simulated streamflows.

The VIC-based 6 km gridded total runoff across HUC8 sub-basins in the main island of Puerto Rico during 1980−2019 is presented. It is observed that the simulated monthly runoffs reasonably reproduce the observed runoffs across all HUC8 sub-basins with NSE > 0.75.[88] As monthly runoffs are computed at the HUC8 sub-basin scale, the variabilities in runoff

[87] Definition from DOE: https://www.energy.gov/eere/water/glossary-hydropower-terms (Accessed September 28, 2022).

[88] Nash–Sutcliffe model efficiency coefficient is used to assess the predictive skill of hydrological models. The Nash–Sutcliffe efficiency (NSE) is calculated as one minus the ratio of the error variance of the modeled time-series divided by the variance of the observed time-series. In the situation of a perfect model with an estimation error variance equal to zero, the resulting Nash–Sutcliffe Efficiency equals 1 (NSE = 1).

performance primarily arise from the disparities in stream gauge densities across these sub-basins.

Simulated streamflow reanalysis data is produced for 1950–2019 across all NHDPlusV2 stream reaches in Puerto Rico which informs the development of flow duration curves and hydropower potential estimates at the NPD locations. Streamflow observations at 98 stream gauges are used to evaluate the streamflow predictability. The median NSE values at daily and monthly scales are ~0.4 and 0.51, respectively indicating that the overall streamflow simulation performance is better at monthly scale. The spatial distribution of NSE across the river network indicates that most of the monthly scale improvement occurs at higher-order streams. The overall streamflow performance across Puerto Rico suggests that simulated streamflows can represent the streamflow observations reasonably with opportunities for further refinement.

In addition to streamflow estimates, hydraulic head was estimated at each using two methods, (1) approximations from reported dam dimensions and (2) digital elevation model (DEM)-based elevation differences. Both of these methods rely on publicly available information, namely the NID and the digital elevation model from the U.S. Geological Survey 3D Elevation Program data catalog (USGS 2022).

Head based on dam dimensions was calculated by applying the same rule-of-thumb estimate used in the Hadjerioua et al. (2012). In the absence of historical records of the hydraulic head or reservoir and tailwater elevations, a representative hydraulic head was calculated as the minimum of either the hydraulic height (difference between the elevation of the reservoir surface the elevation of the stream bed downstream of the dam) and 70% of the height of the dam.

For the estimation of hydraulic head based on elevation differences according to DEM data, several steps were used to facilitate retrieval and processing of information from elevation profiles. These included (1) creating flowline segments, (2) retrieving elevation data, and (3) visualizing elevation profiles and selecting upstream and downstream elevations.

Based on the streamflow and hydraulic head estimates, power, energy, and cost estimates were provided for each NPD using the hydropower design-cost model documented in Oladosu et al. (2022). Across the 18 NPDs for which estimates could be made, a total of 24.5 MW of power potential was found, with the 9 NPDs having at least 1 MW of power potential. These NPDs could provide roughly 80 GWh of annual energy. These results, along with capital cost estimates, were provided to NREL for integration into the broader PR100 effort. Based on discussion with a separate engineering-consulting firm, it is possible that some of the hydraulic head estimates used in this study may be overestimated. Additional information on ORNL's evaluation of NPD hydropower resource assessment will be made available in 2024 after publication of the PR100 final report (DeNeale et al., draft).

4.3.3 Pumped Storage Hydropower

An NREL study on pumped storage hydropower (PSH) used a GIS-based analysis of potential new closed-loop pumped storage hydropower systems in CONUS, Alaska, Hawaii, and Puerto Rico.

The spatially and topographically dependent nature of PSH creates significant challenges for assessing its resource potential, particularly considering the multiple development options available as a site-specific resource. Areas with the greatest density of technical potential and the lowest-cost sites are in regions with higher elevation differences, such the Rocky Mountains, the Cascade Range, and the Alaska Range, which leads to a significant concentration of technical potential in the Western United States (Rosenlieb, Heimiller, and Cohen 2022).

Seven locations in Puerto Rico were identified in the GIS technical potential system results as potentially suitable for PSH totaling 13 GWh of energy storage capacity. However, the lowest-cost systems were found to be significantly more expensive than those found in any other study area, with the minimum modeled cost being $2,829/kW. The lower levels of elevation variation in Puerto Rico limited the technical potential for development of very inexpensive systems; the largest head height of the seven systems in Puerto Rico is 471 m (Rosenlieb, Heimiller, and Cohen 2022).

4.4 Marine Energy and Ocean Thermal

As an archipelago, Puerto Rico has the potential to use energy generated from ocean currents, tides, ocean waves and ocean thermal gradients. A recent study by three national laboratories assesses these technologies in detail (publication forthcoming). The forthcoming report finds that ocean thermal energy conversion, which uses thermal gradients for renewable energy generation holds the greatest potential for Puerto Rico. As this technology requires high temperature differences in the vertical ocean profile there is a need for great ocean depths. These ocean depths with high temperature gradients are found both north and south of Puerto Rico about 25 miles from shore. The Caribbean Sea (south) is found to have higher gradients than the Atlantic Ocean (north). While this study will demonstrate promise in two locations the total practical resource for the whole region is still to be estimated. Additionally, the losses and efficiency of the system are still to be assessed.

The overall assessment from resource characterization of the various possible technologies indicates there are significant resources available for generating various forms of marine energy to provide energy to Puerto Rico. Currently, the LCOE of these technologies are relatively high as these technologies are still nascent, but there is an expectation they have the potential to play a role in the future.

4.5 Floating Photovoltaics

Floating photovoltaic (FPV) systems are mounted on floating platforms installed on the surface of water bodies and connected to grid via floating or underwater cables. The platforms are connected to each other and anchored to the shore, bottom of the water body, or floating anchors.[89] Reservoirs in Puerto Rico have characteristics that work in favor of FPV deployment in Puerto Rico. As compared with reservoirs in the western United States, for example, total water level variation of reservoirs in Puerto Rico tends to be moderate. Challenges for FPV in

[89] "Floating Solar Photovoltaics Could Make a Big Splash in the USA," July 29, 2019, NREL, https://www.nrel.gov/state-local-tribal/blog/posts/floating-solar-photovoltaics-could-make-a-big-splash-in-the-usa.html

the continental United States, such as presence of freight shipping, snow loading, and ice flows, are not factors in Puerto Rico.

NREL is currently evaluating the feasibility of FPV in Puerto Rico (publication forthcoming). Using data from the National Hydrography Dataset (USGS n.d.), waterbodies in Puerto Rico were selected to include those with characteristics that could possibly support FPV. Assuming a 25% coverage of FPV system arrays on the selected water bodies, the preliminary analysis of the study indicates an estimated potential capacity of up to 636 MW_{DC} and an estimated potential annual generation of 1 GWh/year.

A case study of six PRASA and PREPA reservoirs, in which more detailed waterbody morphology data are provided, finds that in the larger reservoirs, a 25% percent coverage assumption is conservative and that some of the larger case study reservoirs could theoretically support high levels of FPV deployment. In this example, Lago Caonillas alone could potentially support over 190 MW_{DC} of FPV capacity.

4.6 Conclusion

After assessing resources and technologies, PR100 results identify that the current and projected energy load can be met using mature technologies—distributed solar, utility-scale solar, utility-scale wind, and refurbishment of existing hydropower. While the assessed emerging technologies could provide benefits to Puerto Rico through 2050, the available resources combined with the mature technologies allow for potential capacity and annual generation to meet demand while also being cost effective and readily deployable.

The assessment shows that utility-scale PV technical potential in Puerto Rico is significant, even in the Less Land variation. This is primarily due to high solar resources, higher capacity densities that are possible with fixed-tilt systems in lower latitudes and the technology advancements that result in increasing PV module capacity and ground cover ratios. Further advancements in generation efficiency, including bifacial modules after 2030, result in increasing energy production over time without changing the land use assumptions set at the beginning of the modeling period. These improvements combine with expected capital and operating cost improvements to result in a decrease of LCOEs over time. A significant initial drop in costs was observed from the beginning of the study period to 2030 and this was due partly to the addition of bifaciality but more importantly, according to this model, to the alleviation of significant price increases from unusual international market conditions present at the onset of the period. Following this period, prices may be expected to increase slightly for a few years starting around 2035, when the ITC expires, but then to fall continuously out to 2050, though at slower rate than in the early years.

In the Less Land variation, significant effort was put into avoiding modeling technical potential in agricultural and ecological land use categories along with protected land, habitat areas, flood zones, and the built environment. While land access constraints in Puerto Rico make this limited access scenario more likely, these restrictions were relaxed in the More Land variation to provide an upper limit of potential production that could be used to compare the effect of these restrictions. The removal of agricultural restrictions in this latter scenario has a significant effect on the technical potential in Puerto Rico (tripling the capacity and generation potential) though this has a much less significant effect on LCOEs.

The rooftop PV technical potential is also found to be significant enough to meet 2021 load. About half of the potential capacity is on rooftops of buildings that are home to low- and moderate-income households. Effectively, this abundant rooftop capacity provides multiple options to increase PV deployment in Puerto Rico. Offshore wind technical capacity was found to be significant and can easily meet the total load for 2021. On the other hand, for onshore wind, the Less Land potential is about a quarter of the wind technical potential for the More Land scenarios. Overall, the More Land scenarios can meet most of the 2021 load. The existing hydropower capacity is insignificant compared to load and increasing the capacity through refurbishments and upgrades will require significant investment. Emerging technologies such as OTEC were also found to have significant technical potential and therefore the ability to meet the 2021 load.

The outputs of this technical potential study do not represent the amount of renewable generation that is likely to be developed in Puerto Rico—they represent the upper boundaries possible under different possible land use and technological advancement scenarios. This analysis was only an initial step in a process of refinement that will eventually result in more complete deployment strategies available to decision makers in Puerto Rico when attempting to reach their policy goals. However, because of the foundational role that technical potential serves in energy modeling, the analysis serves a critical role in the broader effort to develop strategies and design energy systems capable of realizing these goals.

Additionally, carbon emissions reduction was only a part of the motivation for 100% renewable electricity generation goal. Independence from imported fossil fuel, lowering high energy prices for consumers, and improving grid reliability under high hurricane risk were also major factors that led to the 2019 Puerto Rico Energy Public Policy Act (Puerto Rico Legislative Assembly 2019a), and by extension to PR100. To develop an energy system dynamic and robust enough to reach these goals, utility-scale solar production will play only a contributing role. Transmission infrastructure improvements, land-based and offshore wind power, energy storage, and other emerging technologies will be required. However, because of the unique potential for solar production in Puerto Rico revealed by PR100 along with the scale of the energy production required, utility-scale solar production may be expected to play a significant role in the process.

5 Electric Load

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Section Summary

The PR100 electric load projections comprised three subcomponents (see figure below), each of which was separately modeled and summed: end-use loads, energy efficiency savings, and electric vehicle (EV) adoption. The projections were disaggregated by sector (i.e., residential, commercial, and industrial) and region (e.g., municipality) and were generated at an hourly level from FY23 through FY51. Two electric load variations, Mid case and Stress, were created to examine the impacts of different future load trajectories. These results were used in other PR100 modeling tasks, such as distributed solar photovoltaic (PV) adoption and utility-scale capacity expansion and production cost modeling.

The end-use electric usage is based on prior methods with updated data.

The electric loads will be reduced by energy efficiency improvements.

The electric loads will be increased by modeled electric vehicle adoption.

This section discusses the key findings and methodology of the end-use load (Section 5.1), energy efficiency (Section 5.2), and EV (Section 5.3) projections as well as the final load projections (Section 5.4).

Key Findings

End-Use Loads (Section 5.1)

- End-use loads are anticipated to decrease across Puerto Rico by 2050 in the Mid case trajectory, based primarily on population and economic forecasts. This trajectory of downward electricity demand is unlike most electric systems, which anticipate increasing loads even with increased energy efficiency.
- End-use loads into the future are uncertain and might not decrease, assuming other scenario changes (e.g., significant investment in the electric system resulting in a reliable grid); therefore, we examined a range of load trajectories (Mid case and Stress) anticipating that actual loads would be captured within this range. The uncertainty of the load forecasts increases into the future, making it more difficult to draw conclusions from small differences.
- The actual sector-level sales data for FY19–FY22 are higher than what the 2019 integrated resource plan (2019 IRP) originally predicted, implying near-term uncertainty in the long-term downward trend that is anticipated in the Mid case trajectory.

- In the Mid case variation, the contribution of the commercial sector is anticipated to increase over time, whereas in the Stress variation, the contribution of the residential sector is anticipated to increase over time.

Energy Efficiency (Section 5.2)

- The current energy efficiency goal of a 30% end-use energy reduction due to improved efficiency by 2040 is shown to be aggressive compared with results of our bottom-up analysis, which project only an 18% energy efficiency by 2050. Currently, very limited financial resources are available for energy efficiency improvements in Puerto Rico. The bottom-up analysis is described in Section 5.2 (page 124).

Electric Vehicles (Section 5.3)

- A total of 47% of medium- and heavy-duty vehicles were estimated to be electric by 2050 in this Puerto Rico–specific analysis.
- Light-duty EVs (LDEVs) are modeled to reach 25% of the overall fleet stock by 2050. This will have implications for the overall load and impact on the retail rates and other factors.
- In the Mid case trajectory, the proportion of total electricity sales from EVs is projected to reach almost 2% by 2030 and rise to approximately 16% by 2050.
- If energy efficiency goals established in Act 57 are achieved, the impact of energy efficiency savings is anticipated to be greater than the impact of EV load increases across both variations.

Considerations

End-Use Loads (Section 5.1)

- Monitor the actual end-use load trajectory against what has been forecasted here as well as ongoing changes to population and economic forecasts. Into the future, analysis of the measured end-use loads would allow tracking of variations from the various scenario results in this report.

Energy Efficiency (Section 5.2)

- Current programs and activities will need to be significantly accelerated and enhanced to achieve Puerto Rico’s goal of 30% energy efficiency by 2040.

Electric Vehicles (Section 5.3)

- Providing sufficient workplace charging can result in more energy consumption at urban locations during the day. This has multiple benefits: (1) it does not add to an existing and potential high evening peak and (2) the demand corresponds better with solar photovoltaic (PV) electric production.

5.1 End-Use Loads

End-use loads are all the items in a building that use electricity. In this analysis, the focus was just on electricity per the scope of the project; in other regions of the country there are also end-use natural gas loads. Loads are typically dominated by air conditioning, heating, refrigeration, water heating, cooking equipment, lighting, plug loads and industrial loads. In this analysis, the focus was on taking existing hourly end-use loads and determining if in the future these profiles would increase or decrease from year to year.

The Mid case end-use projection used in PR100 shows a general trend of slightly decreasing end-use sales over time. This is primarily because of forecasted long-term declines in population and real GNP. To account for a future in which loads do not decrease as projected, we developed an additional end-use projection: Stress. This projection assumes that the combination of end-use loads and energy efficiency will result in flat annual electricity sales from FY23 to FY51. EV loads will lead to increases in the Stress load above this flat line projection. The energy efficiency projection is described in Section 5.2 (page 124), and the EV projections are described in Section 5.3 (page 138). The creation of the overall Stress electric load variation and its rationale are described further in Section 5.4 (page 168).

5.1.1 Inputs and Assumptions

The PREPA 2019 Integrated Resource Plan used historical population, real gross national product (GNP), cooling degree days (CDDs), and manufacturing employment data to create linear regression equations that project electricity sales for the residential, commercial, and industrial sectors from FY19 to FY38 (Siemens Industry 2019). PR100 used the same linear regression equations developed for the 2019 IRP, incorporated updated projections for each input variable, and extended all end-use load projections through FY51.

5.1.1.1 Population Projections

The 2019 IRP used historical data and projections for population from the Financial Oversight and Management Board for Puerto Rico (FOMB) June 2018 Fiscal Plan for Puerto Rico (FOMB 2018; n.d.). PR100 used historical population data for FY19–FY22 and updated population projections for FY23–FY51 from the FOMB April 2023 Fiscal Plan for Puerto Rico (FOMB 2023a; n.d.). The population projection used in the 2019 IRP is lower than the historical data from FY19 to FY22 and is lower than the PR100 projection from FY23 to FY38 (Figure 64).

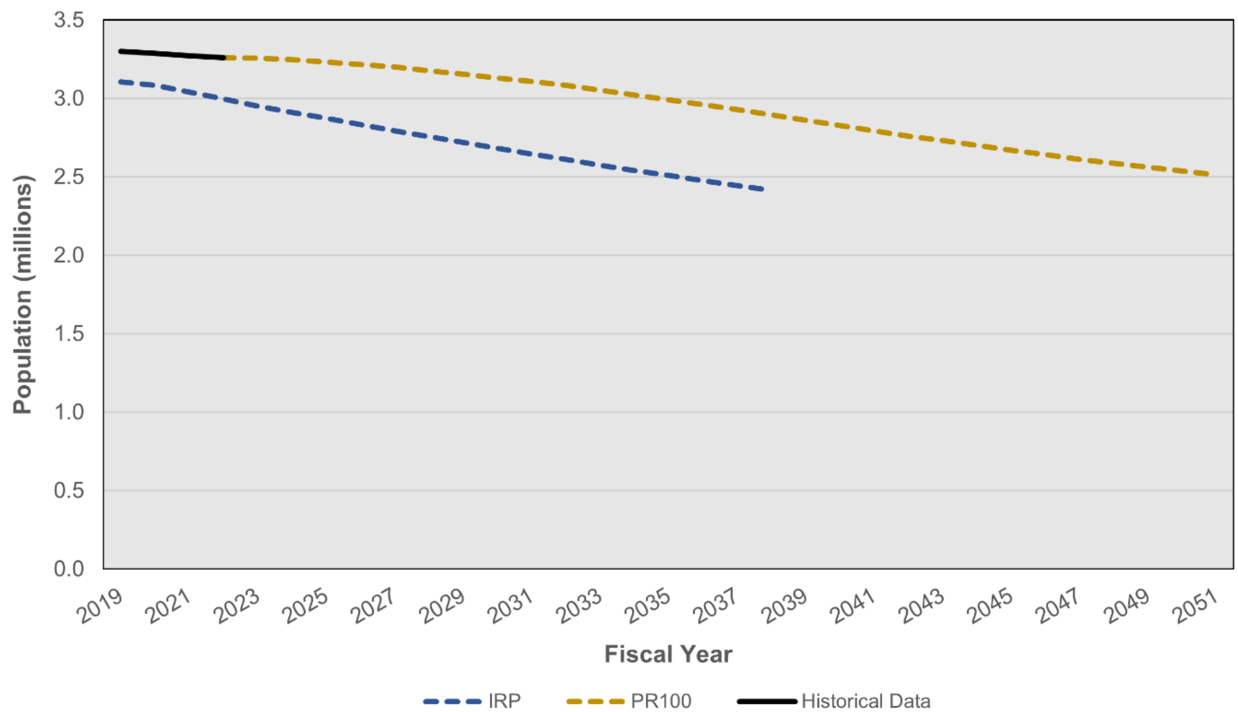

Figure 64. 2019 IRP versus PR100: Population projections, FY19–FY51

The FOMB report discusses several potential explanations for the higher population forecast compared to prior estimates, such as population returning to Puerto Rico at a higher rate than originally expected, COVID-19 temporarily reducing migration from the Commonwealth because of suppressed air traffic, and a higher-than-expected population in the 2020 census. However, the projected long-term decline in population is attributed to ongoing emigration and birth rate trends in Puerto Rico. Another source of uncertainty in population is the ongoing shifts in tourism within Puerto Rico which can significantly impact loads in various seasons. As a major economic driver, tourism will also impact the non-tourist population who support this industry in the future.

5.1.1.2 Real GNP Projections

The 2019 IRP used historical data and projections for real GNP from the FOMB April 2018 Fiscal Plan for Puerto Rico (FOMB 2018; n.d.). PR100 used historical real GNP data for FY19–FY22 and updated real GNP projections for FY23–FY51 from the FOMB April 2023 Fiscal Plan for Puerto Rico (FOMB 2023a; n.d.). The real GNP projection used in the 2019 IRP is lower than the historical data from FY19–FY22, lower than the PR100 projection from FY23–FY37, and higher than the PR100 projection in FY38 (Figure 65). The FOMB projection is based on five main factors: (1) pre-hurricane Maria trends for the Commonwealth, (2) impacts of hurricanes, earthquakes, and COVID-19 on economic activity, employment, and capital stock, (3) stimulative impact of federal and local relief assistance for hurricanes, earthquakes, and COVID-19, (4) stimulative impact of incremental funds from the Infrastructure Investment and Jobs Act, and (5) proposed government efficiency measures, investments, and structural reforms.

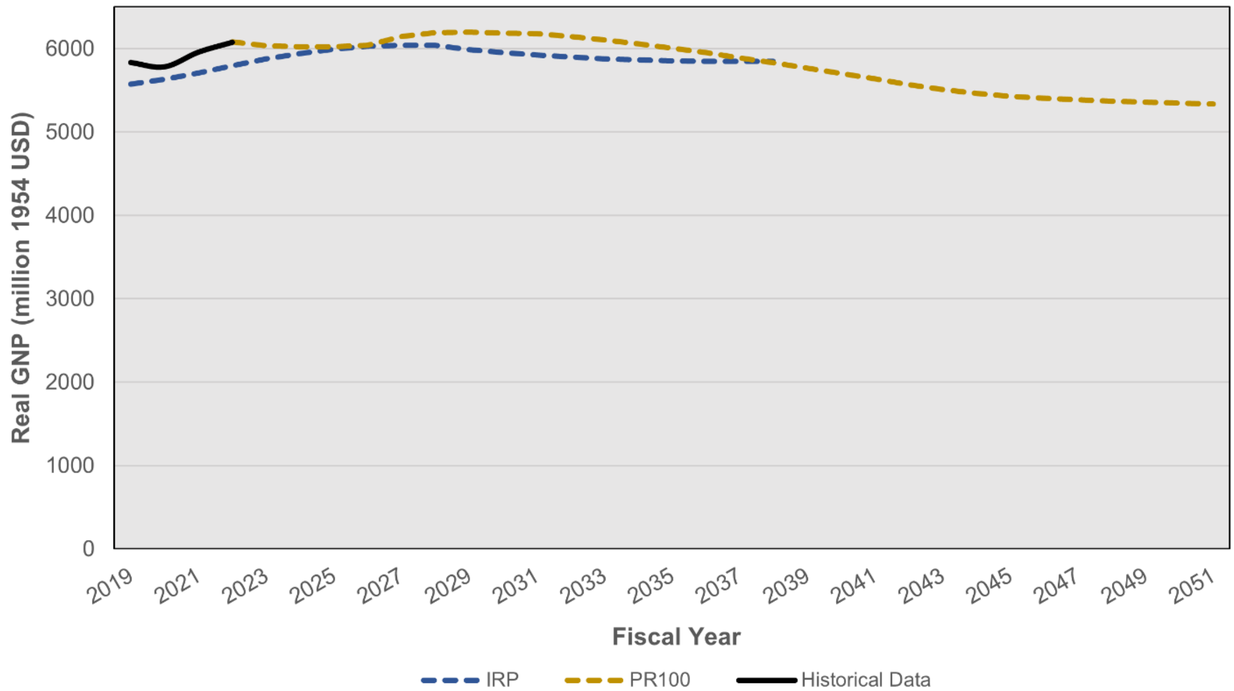

Figure 65. 2019 IRP versus PR100: Real GNP projections, FY19–FY51

5.1.1.3 Cooling Degree Day Projections

The 2019 IRP used average monthly CDD values from the National Oceanic and Atmospheric Administration (NOAA) San Juan Station for the 17-yr period of 2000–2016.[90] Thus, the IRP used a set of 12 repeating CDD values in its annual projections (one for each month, corresponding to the average historical values for that month). The PR100 projection instead used a different CDD value for each month of each year based on a variety of data sources. For July 2018–December 2022, the PR100 projection used historical monthly CDD data from the NOAA San Juan Station. For January 2023–FY51, PR100 used climate projection data developed by Argonne National Laboratory to account for the impacts of climate change (see Section 13, page 507). Argonne provided projected daily mean temperature values for San Juan from 2040 to 2051, which were used to calculate monthly CDD values. The PR100 projection shown used interpolated CDD values for the intervening years of 2023–2039. The average monthly CDD values used in the 2019 IRP are lower than the historical data and PR100 projection for all months (Figure 66).

[90] A cooling degree day (CDD) represents temperature. One CDD corresponds to a daily mean temperature of 1° above 65°F.

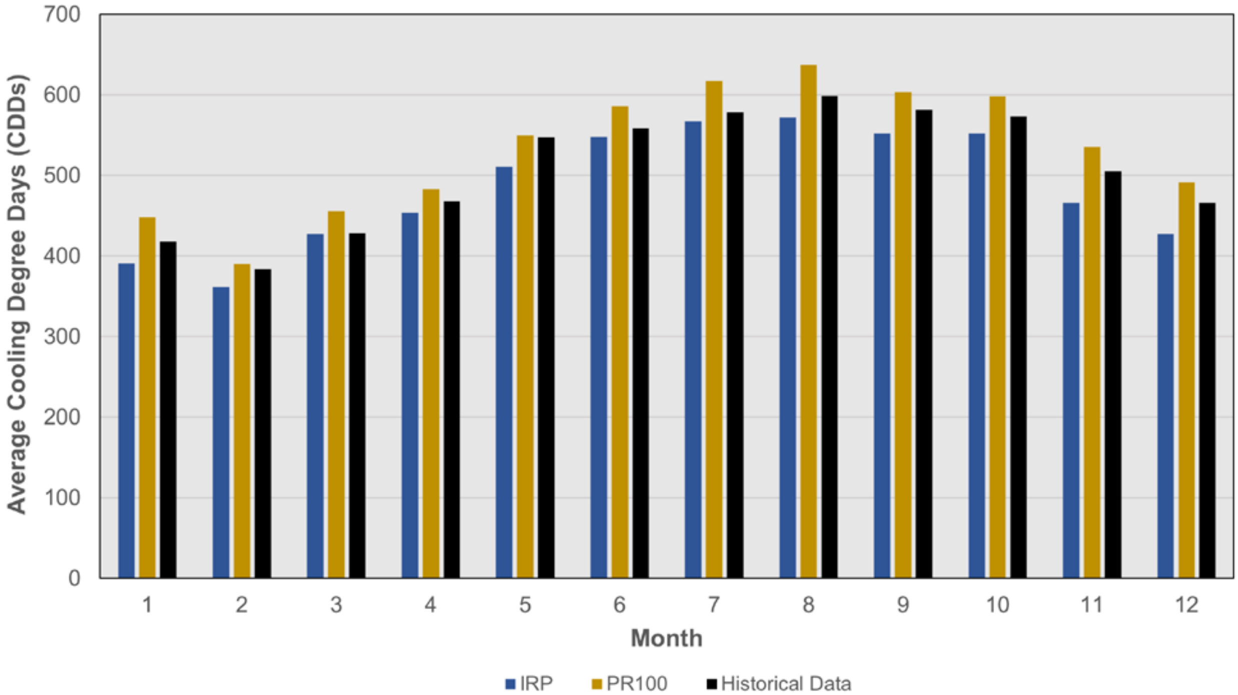

Figure 66. 2019 IRP versus PR100: CDD projections

The IRP data refer to monthly averages, based on historical data from 2000–2016. The historical data refer to monthly averages, based on historical data from 2018–2022. The PR100 data refer to monthly averages, based on climate projections from 2023–2051. Although the CDD data used in the PR100 projections did not consist of monthly averages, they are shown in the figure as such for ease of comparison with the IRP data.

5.1.1.4 Manufacturing Employment Projections

The 2019 IRP used historical monthly manufacturing employment data from the Federal Reserve Economic Data (FRED) and created its own projection for manufacturing employment growth. The PR100 projection used historical monthly manufacturing employment data for July 2018–December 2022 from FRED. From January 2023 to FY51, PR100 applied the monthly growth rates from the manufacturing employment projection developed by LUMA to the starting value, which was the December 2022 data from FRED. Although COVID-19 resulted in a sharp decline in manufacturing employment in April 2020, these values rebounded and exceeded 2018 and 2019 levels in 2022. Thus, since December 2022 is the starting point for the PR100 forward-looking projections, we do not anticipate that the disruption due to COVID-19 will have an impact on the long-term trends. The LUMA-developed projection, which incorporated GNP projections and historical manufacturing employment data, was approved by PREB and FOMB. The monthly manufacturing employment projection used in the IRP projection is lower than the historical data from July 2018 to December 2022 for all months except April 2020—likely because of the COVID-19 pandemic—and is lower than the PR100 projection from January 2023 to FY38 (Figure 67).

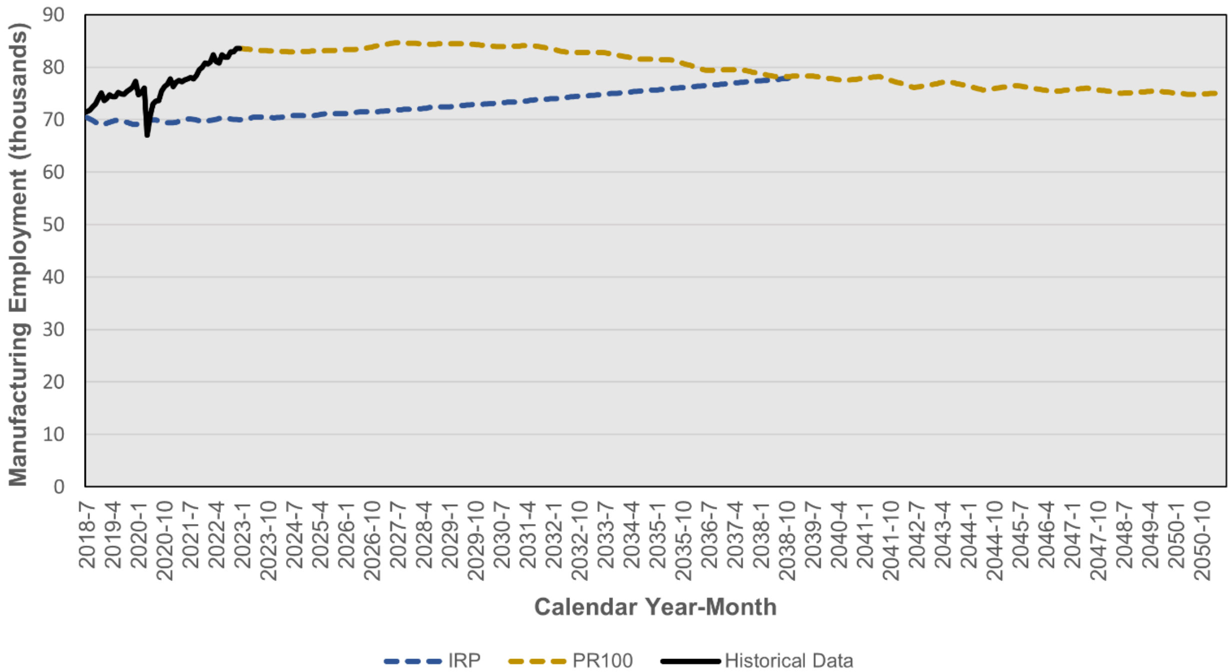

Figure 67. 2019 IRP versus PR100: Manufacturing employment projections, FY19–FY51

5.1.1.5 Conversion of Electricity Sales to Electric Load Methodology

When converting from final sales (i.e., end-use loads, energy efficiency, and EVs combined) to final load, the projections assume technical and nontechnical losses are proportionately allocated to each sector (residential, commercial, and so on). For instance, if a sector accounts for 10% of the total sales, the built-in assumption is that 10% of the losses are allocated to this sector to determine sector-level load. Auxiliary loads (i.e., electricity consumed at the power plant) and PREPA's own use (now assumed to be PREPA and LUMA's own use) are kept separate and added to the combined sector load data to calculate final electric load.

In the IRP projection for FY19–FY38, technical losses are assumed to stay constant at 9.40% of total sales each year, nontechnical losses are assumed to stay constant at 5.40% of total sales each year, auxiliary loads are assumed to stay constant at 751 GWh each year, and PREPA's own use is assumed to stay constant at 34 GWh each year. In the PR100 projection, the assumptions for nontechnical losses and PREPA's own use are the same as those in the 2019 IRP and extended to FY51.

In the PR100 projection, technical losses decline from 9.40% of total sales in FY21 to 5.57% of total sales in FY51 at a constant rate each year. According to EIA data, technical losses as a percentage of electricity sales were approximately 5.57% in 2020 for the continental United States on average. Therefore, the PR100 projection assumes the technical losses in Puerto Rico's transmission and distribution system will decline to this value by FY51. Current technical grid losses in Puerto Rico are almost twice as high as the continental U.S. average. Declines in technical losses can be reasonably expected as grid operations and technology improve, and reaching the U.S. average for 2020 by FY51 might be a conservative assumption.

In the PR100 projection, auxiliary loads do not remain constant at 751 GWh/yr from FY23 to FY51. Instead, auxiliary loads are assumed to decline from 4.48% to 1.00% of total sales from FY21–FY51 because auxiliary loads are 4.48% of FY21 total sales in the 2019 IRP and should be expected to decline as thermal generation is replaced by renewable energy.

Appendix G describes in detail how the end-use loads are determined from the inputs described here.

5.2 Energy Efficiency

We modeled the hourly impact of future energy efficiency adoption on the electricity load forecast. We took two approaches to this analysis, (1) a bottom-up approach that builds on savings anticipated from programs, codes, standards, and natural turnover (described in Sections 5.2.1 through 5.2.3); and (2) a top-down approach in which we assumed compliance with the energy efficiency target of 30% savings by 2040 set in the Puerto Rico Energy Transformation and RELIEF Act (Act 57, as amended) (Puerto Rico Legislative Assembly 2014, 57) and further established in the *Regulation for Energy Efficiency* (PREB 2022a). We refer to the second approach, described in Section 5.2.4, as Act 17 compliant because Act 57 is referenced in Act 17. A comparison of the final trajectories is presented in Figure 75 (page 135). The Act 17 compliant trajectory was used in the scenarios in this study.

Starting with the bottom-up approach, we calculated results for one weekday and one weekend for each month by customer class (residential, commercial, industrial, street lighting), which were then integrated into the overall load forecast. The savings are from natural turnover and codes and standards as well as programs. We modeled savings from end uses[91] that are addressed by energy efficiency programs in LUMA's Transition Period Plan for Energy Efficiency and Demand Response (TPP) (LUMA 2022a). We did not model demand response or agricultural programs.

We based our analysis on hourly electricity consumption by customer sector for FY17 that was compiled by Siemens and used in PREPA's 2019 IRP (Siemens Industry 2019). This data set appears to include constructed data because several months of the residential data have days or weeks that repeat exactly. In particular, there is one week each for July, August, and September that is repeated for the whole month or for 28 days. The other customer sectors do not have repeated days or weeks.

5.2.1 Residential and Commercial Savings

To calculate hourly savings from residential and commercial buildings, we combine estimates of annual electricity savings with normalized load shapes of individual end uses. The rest of this section describes our methodology in detail.

5.2.1.1 General Approach: Annual Savings

Our projections of annual residential and commercial electricity savings are the product of three factors: the annual consumption of an end use, the projected increase in efficiency of the relevant technology, and the share of the stock we expect to turn over during the year (Figure 68).

[91] Lighting, cooling, water heating, and refrigeration.

Annual end use savings = Annual consumption of an end use x Percentage increase in efficiency x Share of stock that turned over

Figure 68. Annual end-use savings formula

Often efficiency savings are calculated on a per-unit basis—for example, using a Technical Reference Manual (TRM)—that assigns an annual savings estimate from replacing one piece of equipment with another. However, we employed the method described in Figure 68 instead for a few reasons. First, because the average annual per-customer electricity consumption in Puerto Rico is lower than in other parts of the 50 U.S. states, per-unit savings estimates sourced from 50-states-settings may be greater than the baseline consumption of that end use in Puerto Rico.[92] Calculating savings as a percentage reduction ensures the per-unit savings are less than the baseline consumption. Second, the per-unit method requires data on the existing stock (e.g., the share of households with air conditioning) to estimate the number of units that may turn over. We are not aware of any such data to leverage. Instead, we use the percentage increase in efficiency to estimate the stock-level savings. Finally, using this method, we can readily calculate savings over time according to projections of increased efficiency of technology.

Annual End-Use Consumption

We principally relied on the National Renewable Energy Laboratory's (NREL's) ResStock and ComStock models to disaggregate the customer sector data into end uses.[93] Because ResStock and ComStock do not cover Puerto Rico, we used Miami-Dade County, Florida, as a proxy based on the similarity of weather and input from discussions with members of the Advisory Group. For some end uses, we used data from other sources as noted below.

Figure 69 shows an overview of the method we used to disaggregate the customer sector data into end uses; Figure 70 shows the specific example of residential electricity consumption. First, we divided the load into cooling and non-space-conditioning consumption.[94] Using the term for CDDs in the linear regression equation from the 2019 IRP, we calculated the share of the load that is weather-dependent and applied it to the FY17 data.

[92] For example, Miami-Dade County, Florida has similar weather to Puerto Rico but more than twice the annual per-customer electricity consumption: approximately 12,700 kWh/dwelling unit (ResStock, 2018 weather) compared to 5,700 kWh/customer (Siemens).
[93] ResStock and ComStock are tools comprising building energy models that are representative of the contiguous U.S. residential and commercial building stock (NREL 2021; NREL 2022). They provide simulated end-use level energy consumption at a 15-min timestep over the course of a year.
[94] We assumed that there is no space heating. See Section 5.2.1.2 for more information on why we chose to manually separate out the cooling load.

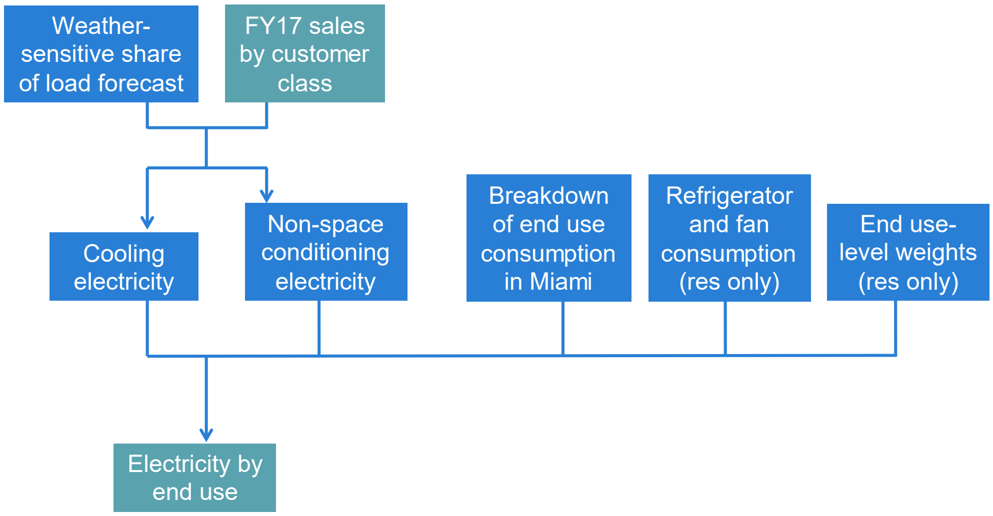

Figure 69. Disaggregating annual electricity to end uses

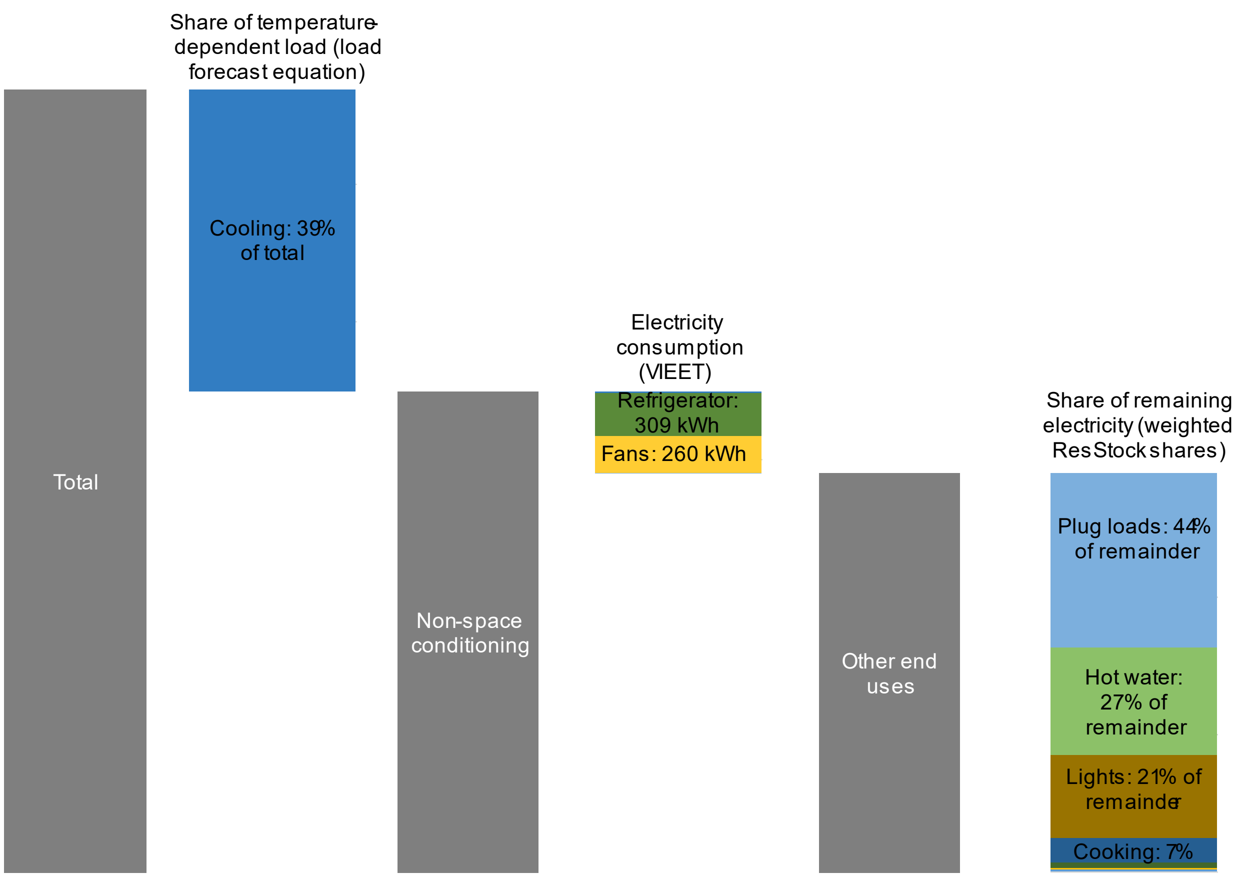

Figure 70. Disaggregating annual residential electricity to end uses

See Section 5.2.1.3 (page 129) and Figure 74 (page 130) for more information about the weighted end-use shares.

For the residential sector, we next separated out refrigerator and fan electricity consumption using electricity units (kWh). We separate refrigeration because refrigerator electricity consumption is less influenced by occupant behavior than other end uses and therefore should be represented in electricity units instead of as a percentage of non-space-conditioning load. Conversely, we separate fans because households likely use fans very differently in Puerto Rico than in Miami (Section 5.2.1.2, page 128). We used the U.S. Virgin Islands Energy Efficiency Tool (VIEET)[6] for these end uses, developed for the U.S. Department of Energy (DOE) by Booz Allen Hamilton through site visits, interviews, and literature review. We disaggregated the remaining consumption into end uses based on the share of the load they account for in the Miami ResStock data. However, because there are likely differences in technology penetrations and usage between Puerto Rico and Miami, we weighted some end uses to increase or decrease those shares. See Section 5.2.1.3 (page 129) for more information. For commercial end uses, we assumed the share of the non-space-conditioning load each end use accounts for is the same in Miami and Puerto Rico—except for heating, which we assume is zero.

Efficiency Increases

In most cases, we took both baseline and projected technology efficiencies from the EIA's 2023 Annual Energy Outlook (AEO2023).[95] For the baseline, we used the 2015 and 2018 "typical" efficiencies.[96] The Annual Energy Outlook also projects "typical" and "high" efficiencies in 2030, 2040, and 2050; we assumed that these projections represent the minimum required by updated standards and the efficiencies that will be incentivized through programs, respectively. For a list of the types of technologies we assumed, see Section 5.2.1.3 (page 129) and Section 5.2.1.4 (page 132).

Stock Turnover

The stock turnover rate was determined by the expected useful life (EUL) of the technology, which we took from AEO2023. For example, if the EUL of an air conditioner is 10 years, we assumed 10% of air conditioners are replaced each year. We assumed there were no early retirements.

Program Participation

To account for program participation, we used what we call an "incentivized share," which we define as the percentage of the stock turnover that participated in the appropriate program and therefore received an incentive.

We set the initial incentivized share so that the sum of the savings for the first 2 years for each sector equals the projections from the TPP, which covers those 2 years. Because some programs affect more than one end use, we cannot infer the projected participation by end use from the TPP. We therefore assumed within each sector each end use has the same incentivized share. We assumed the incentivized shares increase linearly for 5 years and then remain constant through the remainder of the analysis period.

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[95] "Annual Energy Outlook 2023," EIA, https://www.eia.gov/outlooks/aeo/.

[96] The first release of the AEO2023 uses efficiency data published in 2018. The baselines were last updated from contractor, manufacturer, and standards data in 2015 for residential and 2018 for commercial. The second release contains updated data, which we were not able to incorporate given the timing of our analysis.

5.2.1.2 General Approach: Hourly Load Shapes

Figure 71 shows that the residential average hourly load shape by month for Puerto Rico and Miami are very different. The average load in Puerto Rico had less variation than the average load in Miami. In addition, the Puerto Rico load was the lowest during the middle of the day and peaked around 10 p.m., whereas the Miami load is lowest at 3 a.m. and peaks around 4 p.m. during most months. The commercial load shapes in Puerto Rico and Miami are less different (Figure 72).

We believe that differences in electricity usage for space conditioning account for much of the difference in observed residential load shape and proceeded as follows. First, we assumed zero space heating electricity consumption in Puerto Rico. Second, according to feedback from members of the Advisory Group, households in Puerto Rico tend to run their air conditioning at night and rely on fans and windows during the day (however, there is still uncertainty about this behavior, and it might be more common among lower income homes). To disaggregate the end-use shapes, we assumed the remaining difference in load shapes between Puerto Rico and Miami are the result of this pattern of air conditioner use.

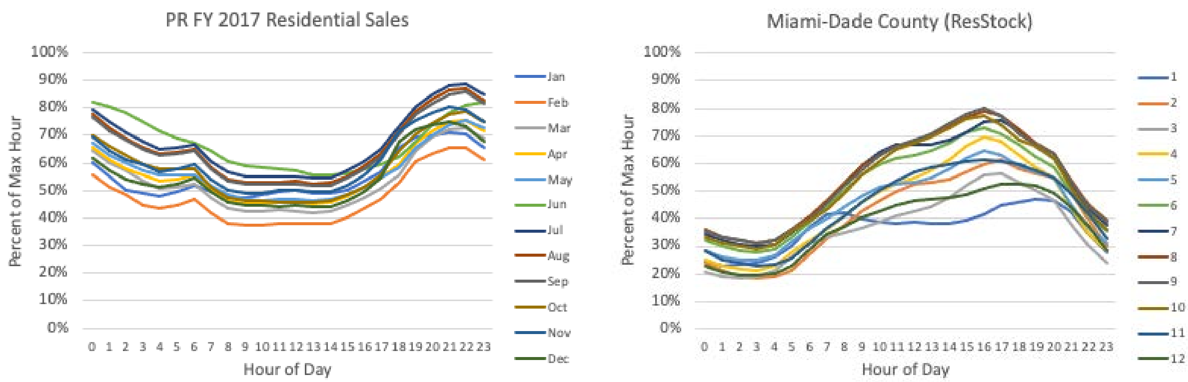


Figure 71. Residential average hourly load shapes by month: Puerto Rico versus Miami-Dade County

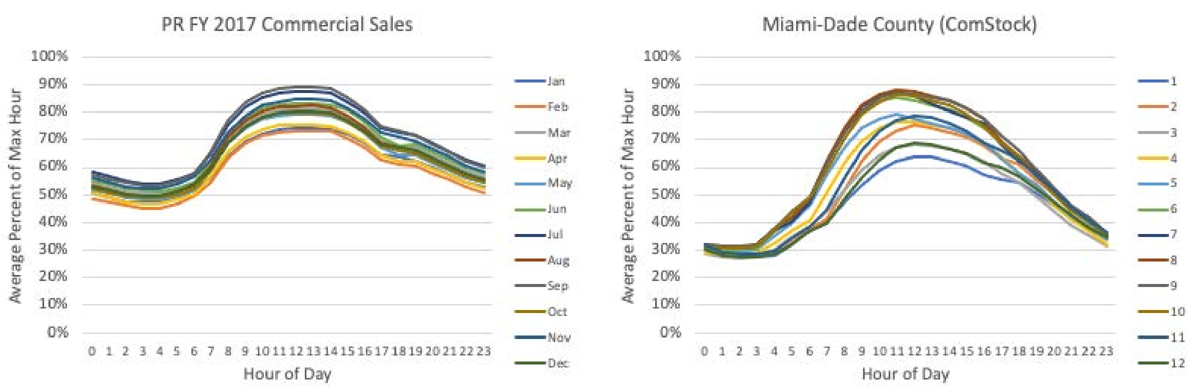


Figure 72. Commercial average hourly load shapes by month: Puerto Rico versus Miami-Dade County

To disaggregate the hourly load into end uses for both residential and commercial buildings, we scaled the Miami non-space-conditioning load so that the total annual consumption matched the total non-space-conditioning Puerto Rico consumption calculated above. We then calculated the cooling load shape as the difference between the non-space-conditioning load in Miami and the overall load in Puerto Rico (Figure 73). The inferred cooling load shape is consistent with the air conditioning behavior discussed above.

For residential, we assumed fan electricity consumption is constant throughout the day rather than peaking at night as it does in Miami because it is likely the main source of cooling during the day. For the other residential end uses and commercial end uses apart from cooling, we assumed the Puerto Rico end-use shapes are the same as those in Miami.

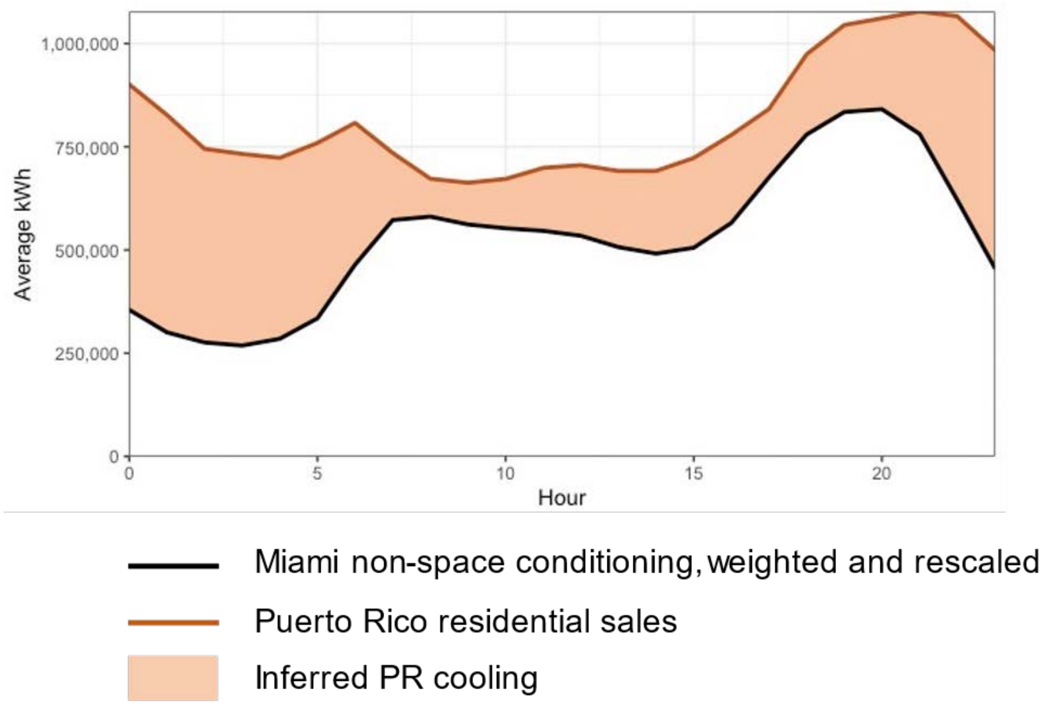


Figure 73. Illustration of disaggregating the residential cooling shape: January weekday

We assumed savings shapes from efficient technologies are the same as the end-use consumption shapes. In other words, energy efficiency savings for an end use are proportional to the amount of consumption of that end use in each hour.

5.2.1.3 Residential Assumptions

End-Use Electricity Consumption

We took annual energy consumption for refrigerators and fans from the U.S. Virgin Islands Energy Efficiency Tool (VIEET),[97] developed for the U.S. Department of Energy (DOE) by Booz Allen Hamilton through site visits, interviews, and literature review. We chose the VIEET refrigerator consumption estimate (665 kWh/household/yr) because it is higher than the AEO estimate of "typical" consumption and easier to square with savings estimates from Puerto

[97] This tool is not publicly available.

Rico's Weatherization Assistance Program (DEDC WAP 2021). Even though we used this, the per-unit *savings* estimate for refrigerator replacement from the WAP (805 kWh/household/yr) is higher still than the VIEET *consumption* estimate, but the WAP replacements were likely targeted at particularly inefficient refrigerators that are not representative of the overall stock. For ceiling and stand fans, we chose the VIEET estimate of 552 kWh/household/yr because fan usage in the U.S. Virgin Islands is likely more representative of Puerto Rico than fan usage in Miami, where the penetration of air conditioning is almost 100% (ResStock). We did not take other consumption estimates from the VIEET because even their low estimate is larger than the consumption in Puerto Rico (approximately 8,000 kWh/household/yr compared to 5,700 kWh/customer/yr).

We weighted the remaining residential end uses to account for differences between Puerto Rico and Miami as shown in Figure 74. A weight of 1 indicates that we did not reduce the relative proportion of an end use in Puerto Rico compared to Miami. A weight of 0.5 indicates that we assumed the proportion of that end use is half of what it is in Miami. Several of the end uses, including all those related to space heating, were assigned a weight of 0.

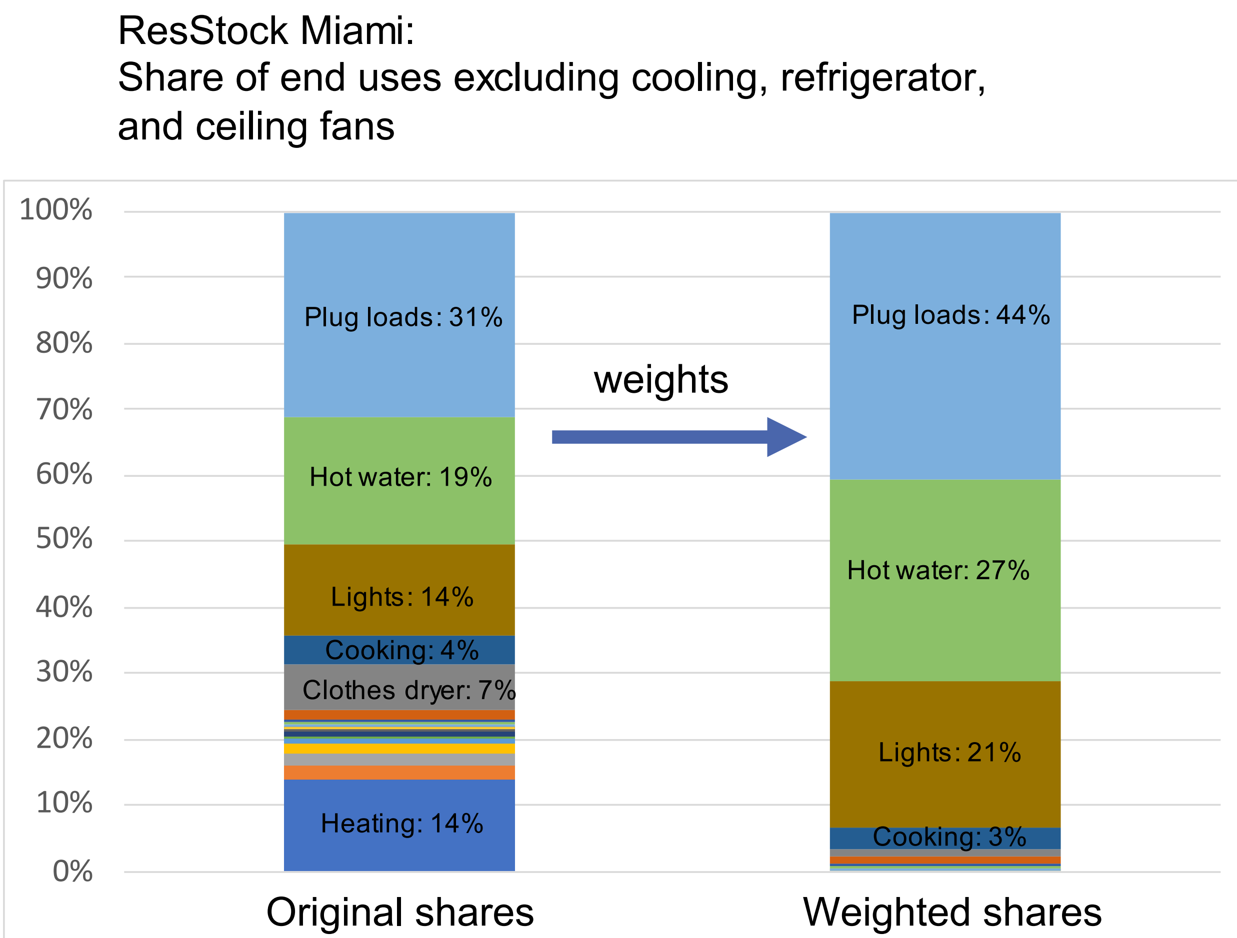


Figure 74. Weighting of residential end uses

The weights we used are shown in Table 17.

Table 17. Residential Annual End-Use Weights

ResStock End Use	Weight
Clothes dryer	0.1
Clothes washer	0.75
Cooking range	0.5[a]
Dishwasher	0.5
Exterior lighting	0.5
Garage lighting	0.1
Interior lighting	1
Plug loads	0.822[b]
Hot water	1[c]
Well pump	0.5

We assumed the following ResStock end uses are all zero in Puerto Rico: bath fan, range fan, pool heater, pool pump, hot tub heater, hot tub pump, heating fans, extra refrigerator, stand-alone freezer, heating, supplemental heating, and heating-related pumps.

[a] More than half of households in Puerto Rico do not use electric cooking[98]; 83% of households in Miami have electric cooking (ResStock).

[b] Share of households with a computer in Puerto Rico relative to Miami (American Community Survey Table S2801).

[c] 87% of Miami has electric hot water (ResStock).

Efficiency Measures and Programs

Table 18 shows the measures that LUMA proposed to incentivize in the TPP and the assumptions we used to model them. Unless otherwise noted, the efficiencies required by minimum standards and the programs were taken from EIA 2023, which includes decadal projections through 2050.

Table 18. Residential Energy Efficiency Measures and Assumptions

End Use	TPP Measures	Our Assumptions	Sources/Notes
Cooling	Ductless air conditioner Window air conditioner	Window air conditioner efficiency projections from EIA (2023a)	EIA (2023a) does not list ductless systems (heat pumps or mini-splits)
Lighting	ENERGYSTAR LED lighting	Baseline: 50-50 incandescent-LED Natural turnover: 50-50 CFL-LED Incentivized turnover: LED	More than half of homes in each of the 50 U.S. states have at least 50% LEDs (EIA 2020)

[98] https://www.powermag.com/building-puerto-rican-resiliency-with-lpg-fueled-engines/

End Use	TPP Measures	Our Assumptions	Sources/Notes
Water heating	Solar water heater Tankless water heater	Baseline and natural turnover: electric resistance tank Incentivized turnover: solar	EIA (2023) has lower efficiencies for tankless than electric tank NREL's Puerto Rico Energy Efficiency Scenario Analysis Tool shows higher consumption for tankless than electric tank
Food services	ENERGYSTAR refrigerator	Baseline: VIEET Natural and incentivized turnover: EIA (2023a)	

[a] In other words, we assumed ductless air conditioners increase in efficiency at the same rate as window air conditioners.

Our projected share of annual stock turnover that participated in a residential program starts at 2.7% in FY22 and grows to 13.5% in FY26 through FY51.

5.2.1.4 Commercial Assumptions

End-Use Electricity Consumption

We used the distribution of end uses in commercial buildings in Miami from ComStock to disaggregate the Puerto Rico commercial load. We did not weight them because we had less reason to believe there are significant differences than in the residential sector. We excluded space heating as well as district heating and cooling.

Efficiency Measures and Programs

Table 19 shows the measures that LUMA proposed to incentivize in its commercial efficiency programs and the assumptions we used to model them. Unless otherwise noted, the efficiencies required by minimum standards and the programs were taken from EIA 2023, which includes decadal projections through 2050.

Table 19. Commercial Energy Efficiency Measures and Assumptions

End Use	TPP Measures	Our Assumptions	Sources/Notes
Lighting	Linear fluorescent LED troffer Omnidirectional exit sign	Baseline: 50-50 linear fluorescents and LEDs Natural turnover: replace fluorescents with fluorescents and LEDs with LEDs Incentivized turnover: replace fluorescents with 50-50 fluorescent and LEDs; LEDs with LEDs	Yamada et al. (2019) estimates 50-50 fluorescents and LEDs in 2020 but does not break down into particular types of fixtures
Lighting	Occupancy sensor	37% savings 50% of incentivized lighting replacements include occupancy sensors	Yamada et al. (2019)

End Use	TPP Measures	Our Assumptions	Sources/Notes
Cooling	Rooftop AC Chillers	EIA (2023) efficiencies for commercial rooftop AC	ComStock shows that 80% of cooling electricity in Miami and Hawaii is from packaged rooftop units
Cooling	Window film	Not modeled	
Water heating	Water heating	Baseline: electric resistance tank (0.98 EF per EIA [2023]) Incentivized turnover: heat pump (3.9 COP per EIA [2023])	
Food services	Refrigerator	Average of commercial reach-in refrigerators, commercial reach-in freezers, commercial walk-in refrigerators, commercial walk-in freezers	
Food services	Combination oven Convection oven Fryer Ice machine	Not modeled	No efficiency information in EIA (2023)
Pumps	Pool pump VFD	Not modeled	

Although the TPP Business Rebate Program includes savings from industrial and agriculture as well as commercial, we classified all savings from industrial and agricultural buildings, as opposed to process loads, as commercial savings.

The share of annual stock turnover that participated in a commercial program starts at 7.4% in FY22 and grows to 37% in FY26 through FY51.

5.2.2 Street Lighting Savings

Table 20 shows our assumptions for calculating the electricity savings associated with installing LED street lights compared to the baseline consumption.

Table 20. Street Lighting Electricity Savings Assumptions and Sources

Assumption		Source
350,000	Street lights to replace	TPP
3.9 years	Time to replace them	TPP
457 kWh/yr	Savings per light that is replaced before 2035	TPP Year 1 savings
628 kWh/yr	Savings per light that is replaced after 2035	Yamada et al. (2019)
16 years	EUL	DOE, Better Buildings (2016)

We assumed the electricity savings do not change the street lighting load shape.

5.2.3 Industrial Savings

Based on the achievements of DOE's Better Plants initiative, we assumed 1.15% of the manufacturing footprint will participate in an efficiency initiative each year and that each participant will save 25% of their annual consumption over 10 years (DOE, Better Plants 2021; DOE, Better Plants n.d.)(DOE 2021b; n.d.).[99] We assumed the electricity savings do not change the industrial load shape.

5.2.4 Act 17 Energy Efficiency Goal

Puerto Rico's Energy Efficiency Regulation requires Puerto Rico to achieve 4,744 GWh/year of electricity savings by 2040, based on 30% of PREPA's fiscal year 2019 sales (PREB 2022). The projected savings based on the bottom-up approach described in previous sections do not achieve that goal.

To create a projection compliant with the regulation, we first assumed all replacements of residential and commercial equipment were covered by the proposed programs and therefore are high efficiency.

This 100% participation scenario still does not reach the target, so we then scaled it so that the FY40 electricity savings are 4,744 GWh. One potential way that the savings could be higher than our previous estimates is for the efficiencies of the individual technologies to increase more than projected by AEO, perhaps because of a technological breakthrough. Because such a breakthrough becomes more likely as we look farther into the future, we increased the scaling factor linearly through FY40, when it reaches about 1.345. We scaled all sectors equally. After 2040, we held the savings constant. Figure 75 shows all three of these cases.

As can be seen, achieving the Act 17 requires significant growth in energy efficiency through 2040. Current programs and activities will need to be significantly accelerated and enhanced to achieve this goal.

[99] Between 2009 and 2021, 13.8% (or 1.15% per year) of the U.S. manufacturing energy footprint participated in the Better Plants initiative. The savings target is typically 25% energy savings over 10 years; we assume that this represents 25% each of electricity and gas consumption.

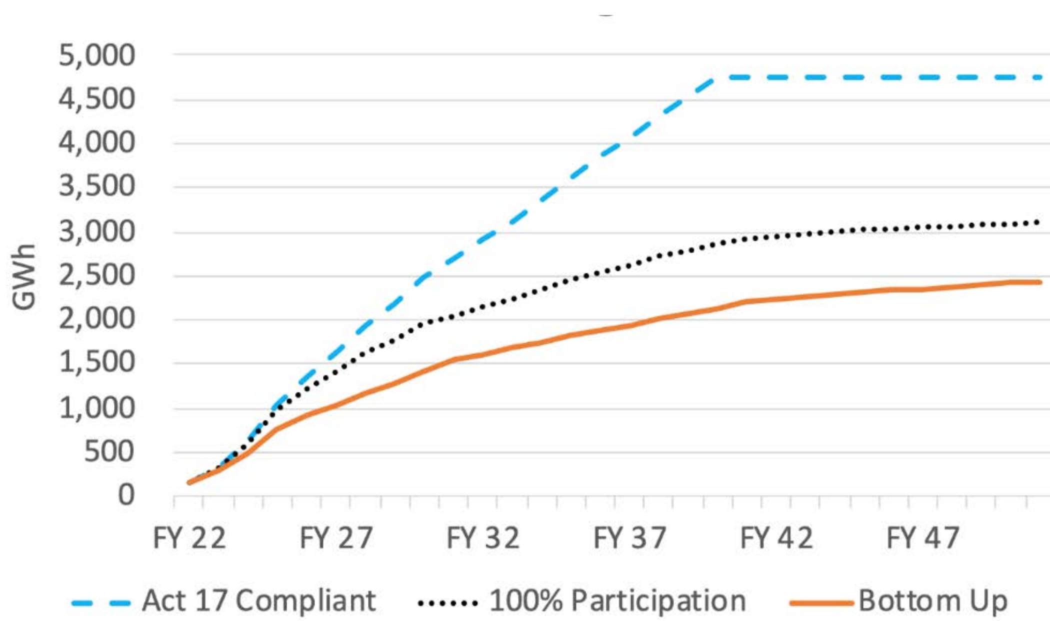


Figure 75. Energy efficiency savings estimates: Bottom-up, 100% participation, and Act 17 compliant

We used the end-use shapes that we derived as described above to convert the annual savings to hourly savings.

5.2.5 Utility Program Costs

5.2.5.1 Residential and Commercial

In our Act 17-compliant scenario, 100% of the replacements of equipment covered by an energy efficiency program participate in that program through 2040. Therefore, all savings through 2040 are paid for by the utility programs. After FY40, we set program participation in each year at the level required to hold the electricity savings constant. This results in a much lower participation rate but not a zero-participation rate. With no program participation, the savings would decline as equipment reached the end of its life and was likely replaced with a less efficient version due to the cost-sensitive population.

For both scenarios, we calculate program costs using a per-kWh value derived by averaging the estimates for the 2 years in the TPP. These values are \$0.37/kWh of annual savings for residential and \$0.46/kWh of annual savings for commercial for the first year (program cost/annual savings from the TPP). For our cost calculation, we measure program kWh savings relative to electricity consumption from a zero-program-participation baseline, in which baseline efficiency improves solely because of equipment standards improving over time. Although program costs will likely change over time as programs become established and the composition of the portfolio evolves, we do not have data to support any particular cost trajectory. We do not change these costs based on the extent of program participation in our two scenarios, which effectively assumes program administrators can achieve 100% program participation without offering more generous incentives per kilowatt-hour of savings. This likely underestimates the cost of Act 17 compliance.

5.2.5.2 Street Lighting and Industry

We did not include program costs for street lighting because the projects are currently being funded by the Federal Emergency Management Agency (FEMA) rather than by LUMA(2022a). We did not include program costs for the industrial sector because TPP programs that address both commercial and industrial savings were accounted for in the commercial sector, and LUMA did not propose any programs that are only for industrial customers. The industrial savings that we modeled are based on a voluntary initiative that does not receive program funds.

5.2.6 Energy Efficiency Results

Figure 76 shows the distribution of savings between the sectors. In both the bottom-up and Act 17-compliant cases, residential and commercial buildings contribute the bulk of the savings, rather than street lighting or industry. In the bottom-up case, residential starts at about 60%–70% of savings and then declines to 30% by the end of the study period. In the Act 17-compliant case, residential savings maintain a higher share throughout. This is because the participation rate inferred from the TPP in the bottom-up scenario is smaller for residential than for commercial (14% versus 37% after 5 years; see Section 5.2.1 for details). Therefore, raising the participation rate to 100% in the Act 17-compliant case increases the residential participation rate.

The street lighting share of savings peaks in FY25. All existing lamps are replaced by then, and because of their lifetime, there are no new street lighting savings for the next 16 years.

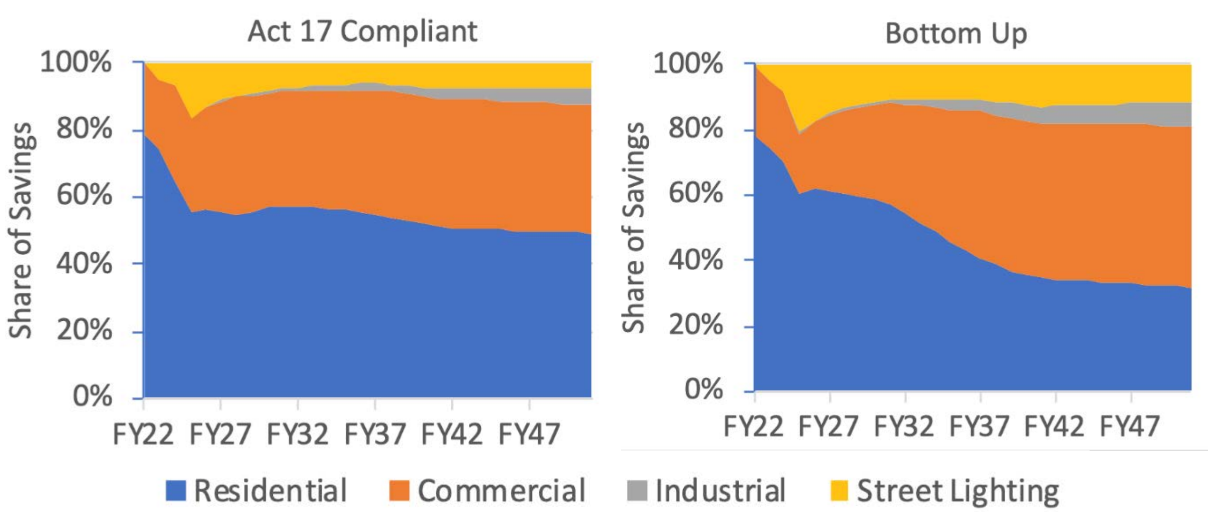


Figure 76. Share of total estimated savings by sector

Figure 77 and Figure 78 show the average hourly savings for the two cases in FY25 and FY50 for the residential and commercial sectors, respectively. In residential buildings, the savings peak at 9 p.m., which is a bit before the overall residential peak because lighting contributes a large share of the savings. The savings are still substantial later at night, however. The two cases are more different in FY50, in large part because there has been more time for the differences in participation rate to build up.

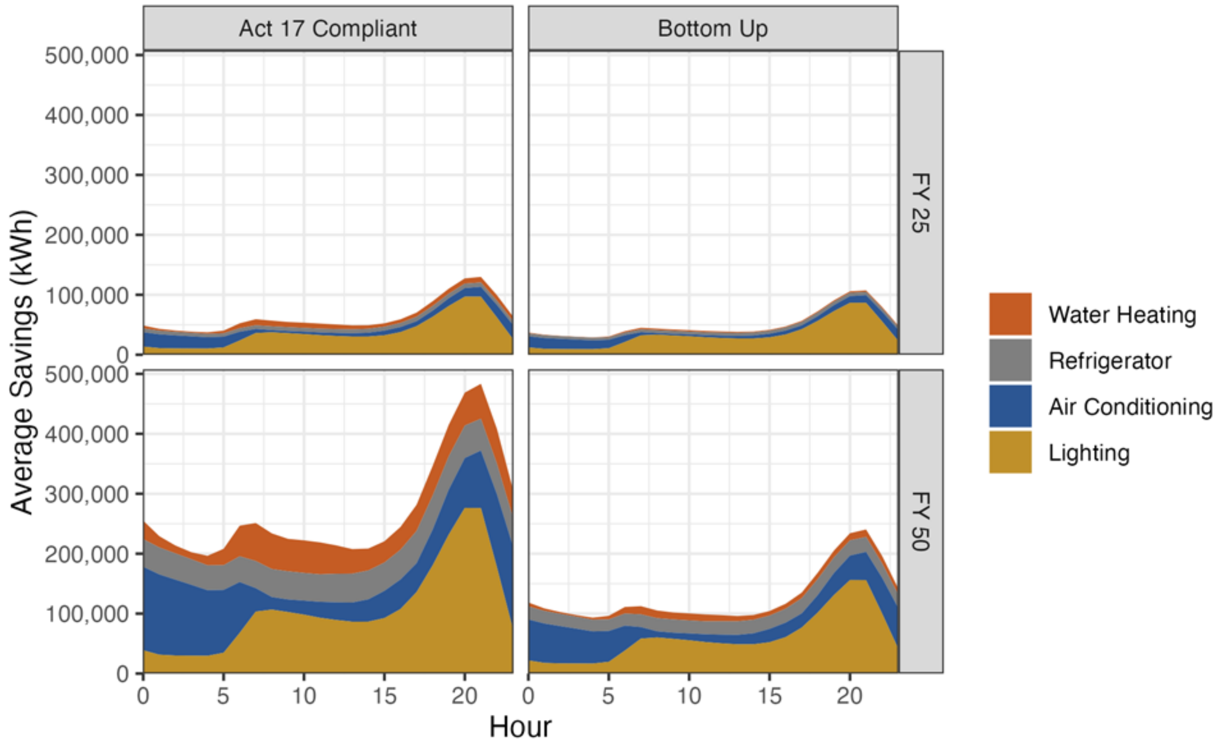


Figure 77. Average hourly electricity savings: Residential

In commercial buildings, lighting upgrades yield most of the savings, with some contribution from air conditioning. The cooling savings remain high overnight because of our method for inferring the cooling load shape. The baseline commercial load shape from FY18 is flatter than ComStock's for Miami-Dade county, so we attribute the difference to cooling (Section 5.2.1.2, page 128).

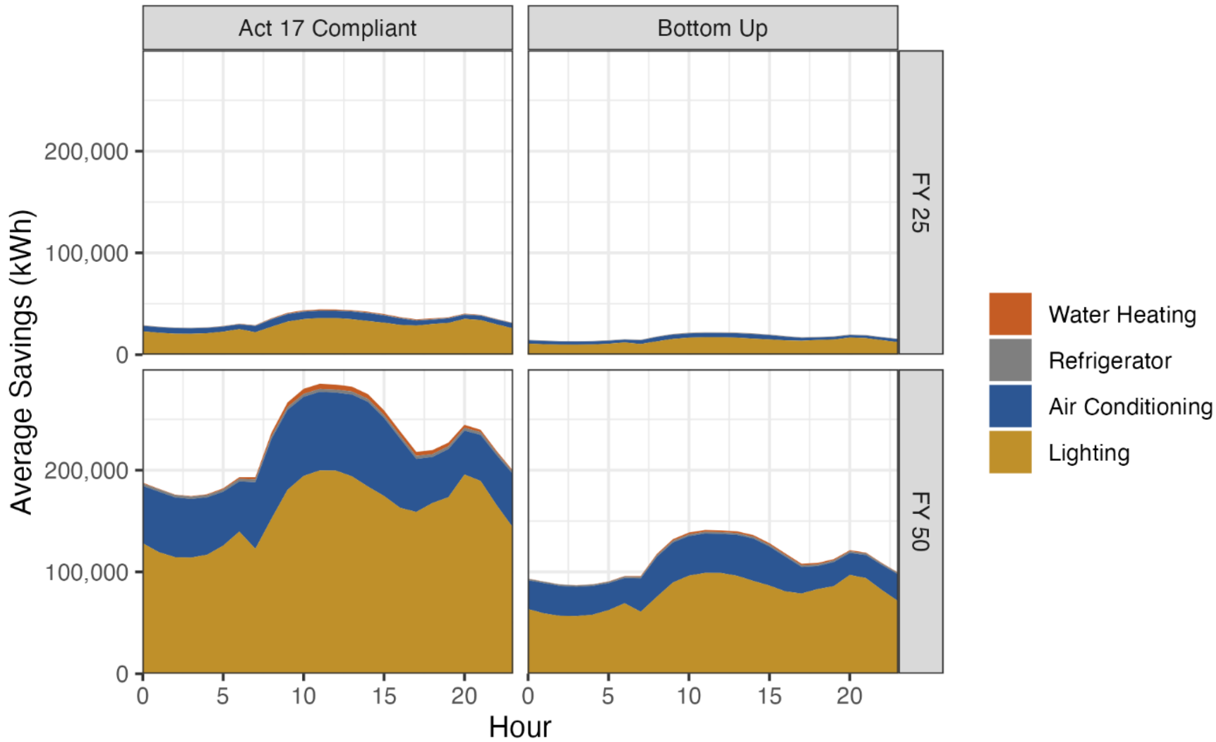


Figure 78. Average hourly electricity savings: Commercial

5.3 Electric Vehicles

This section presents electric vehicle (EV) load estimations for Puerto Rico for the study years 2020 through 2050. Section 5.3.1 details light-duty electric vehicle modeling. Light-duty vehicles include passenger cars and pickup trucks, generally defined as vehicles weighing less than 10,000 pounds. Light duty vehicle modeling includes vehicle use for commuting as well as for local transport within a region, such as to run errands, visit friends or family, etc. Medium- and heavy-duty EV analysis is presented in Section 5.3.2. Vehicles include shuttles, moving vans, garbage trucks, and semi-trucks. Medium- and heavy-duty vehicles are generally used for commercial purposes, and the modeling focused on the transport of goods across Puerto Rico. Both light-duty and medium- and heavy-duty EV analyses focused on generating municipality-by-municipality temporal charge profiles, which were integrated into the PR100 load modeling as described in Section 5.4.

5.3.1 Light-Duty EVs

Because of the anticipated increases in light-duty EV adoption, utilities are interested in future increases in electric load demands. A detailed understanding of light-duty load demands requires a spatial-temporal analysis to define specific needs that are dependent on the year and area. We based our estimate of the number of light-duty EVs in Puerto Rico from now until 2050 on observations and forecasts produced by a secondary source. Estimates of light-duty EV charging locations are challenging and not addressed in existing tools or literature. Unfortunately, very little data are available that describe vehicle locations and driving behaviors. To overcome the lack of data, this work used what is provided by the U.S. census and open-source road network GIS data to estimate driving energy consumption and charging locations. After estimating the energy, the final step in the analysis converted the daily energy into hourly demand profiles by finding the likely curves that produced the estimated energy. The assessment found that Puerto Rico will likely reach a light-duty EV adoption of around 25% by 2050. Most light-duty EVs were adopted in higher income areas that have many drivers.

5.3.1.1 Overview of Puerto Rico Drivers and Income

Puerto Rico is an archipelago of islands in the Caribbean, three of which are inhabited, with a total land area of about 9,104 km^2 and a population of just over 3 million people. It includes a road network of about 14,400 km that circumnavigates the main island and connects the north with the south with roads that traverse mountainous terrain (Birk Jones, Bresloff, et al. 2022). Many of the roads are used on a regular basis by 1.7 million drivers for commuting, entertainment, errands, or other purposes. According to the U.S. Census, about one million people drive from one municipality to another municipality for work. Historical values of light-duty EV adoption based on anecdotal information indicate strong upward growth, such as from 1,800 in 2021 to 2,500 in 2022.[100] The available data do not describe the location of each registered light-duty EV in Puerto Rico. Therefore, estimates of light-duty EV registration locations require a data-driven model.

The spatial distribution of all the drivers in Puerto Rico is described in the top map of Figure 79. This map shows that most drivers are within the San Juan municipality located in the northwest section of the main island. The municipalities around San Juan (e.g., Carolina, Trujillo Alto, Gurabo, Guaynabo, and Bayamon) represent the economic center for Puerto Rico and have the highest median incomes, as indicted by the bottom map in Figure 79.

[100] "Insufficient EV Recharging Infrastructure in Puerto Rico," *The Weekly Journal*, Efraín Moltabán Ríos, June 3, 2022, https://www.theweeklyjournal.com/business/insufficient-ev-recharging-infrastructure-in-puerto-rico/article_b3bced94-e377-11ec-a58c-0724f97ee8b1.htm.

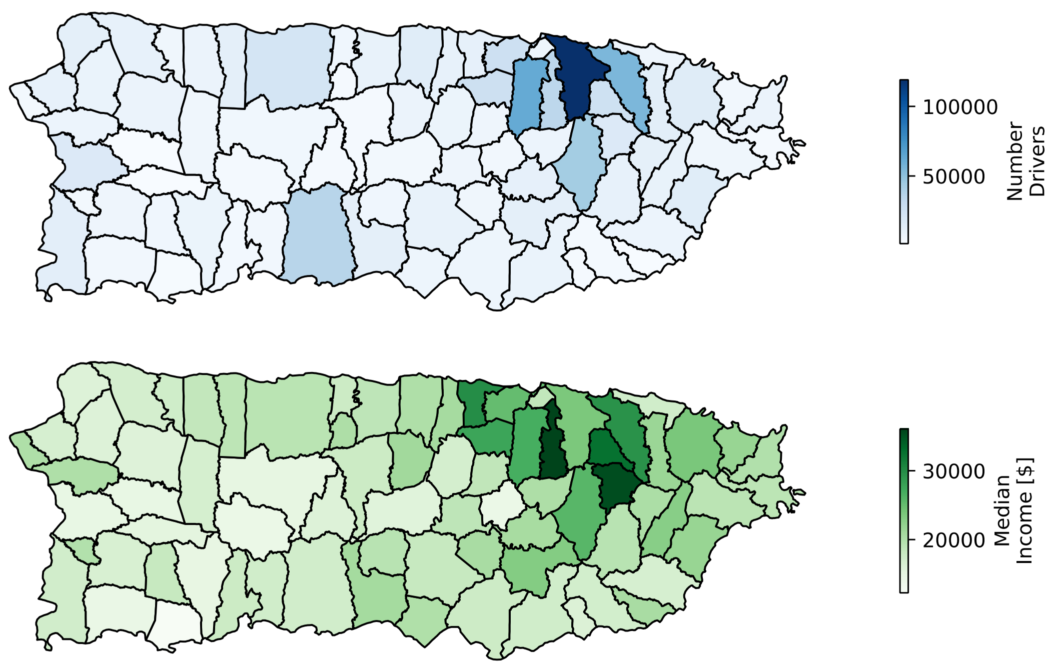


Figure 79. Spatial distribution of light-duty vehicle drivers throughout Puerto Rico (top) and median household income for each municipality in Puerto Rico (bottom)

Although Puerto Rico is small, it has mountainous terrain in the center that will impact vehicle energy consumption. Some of the mountains exceed 1,000 m and many roads include steep slopes. Even roadways along the northern coast cross many valleys that require vehicle engines to exert significant energy to traverse.

5.3.1.2 Analysis Methodology

The block diagram in Figure 80 describes the analysis for determining the number of light-duty EV adoptions in each subregion at future time-steps. The analysis procedure begins with two parallel assessments: one predicts future light-duty EV adoptions for the entire territory and the other is a spatial model that estimates the distribution of adoptions by municipality across Puerto Rico. After estimating the number of light-duty EVs, the analysis attempts to understand driving behaviors using the U.S. census data. The number of vehicles and the commuter behaviors are inputs into a model that computes the energy required to drive from a resident's home location to work and then back. The energy for each trip is then used to estimate the light-duty EV charging profiles.

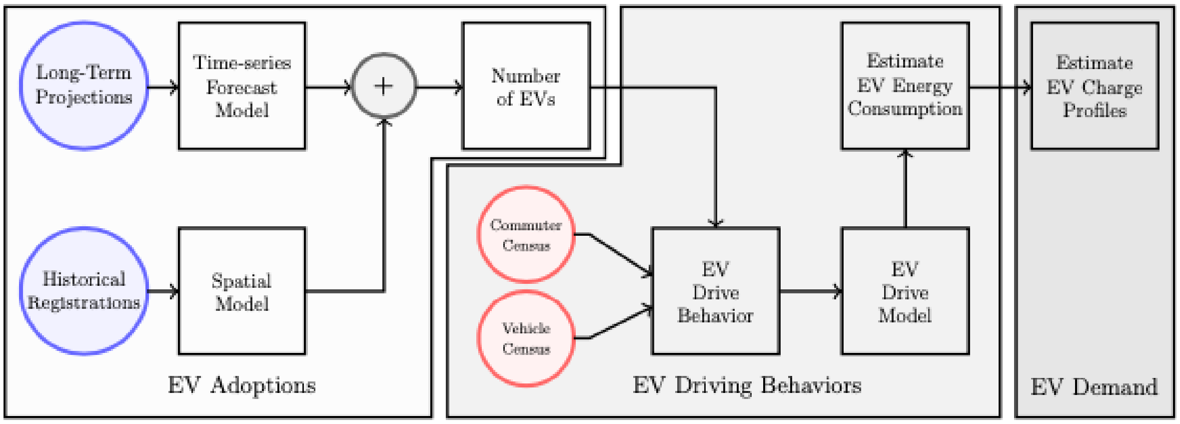


Figure 80. Block diagram depicting the temporal and spatial analysis used to estimate the EV adoptions and the locations within Puerto Rico's municipalities

5.3.1.2.1 Time-Series Forecast Model

The forecast model for estimating light-duty EV adoptions considers both policy and economic factors to predict future adoption levels. The scope of this analysis did not entail the creation of a time-series adoption model. Instead, this work leveraged an existing tool created by Energy Policy Solutions (EPS) ("U.S. Energy Policy Simulator" 2022), which provided an open-source, web-based modeling environment.

This simulator, at the time of use, provided a prediction for future light-duty EV adoptions in only a subset of the 50 states. The simulator also did not include Puerto Rico. Therefore, a state with economic and climate conditions that best resembles Puerto Rico was picked. The most representative state was Louisiana. However, an exact match did not exist. Louisiana's median income just exceeds $50,000, while Puerto Rico's median income equals $21,058. Individual Puerto Rico municipalities (equivalent to counties in the 50 U.S. states) had median incomes that range from $12,283 to $36,073.

Because the median incomes in Louisiana and Puerto Rico do not match exactly, this work applied a correction factor of 0.42 to Louisiana's adoption forecast. This correction factor was the median income of Puerto Rico ($21,085) divided by Louisiana's median income ($50,000). This resulted in an adoption curve that resembles the plot in Figure 81, which predicted the percentage of light-duty EVs for Puerto Rico from 2020 to 2050.

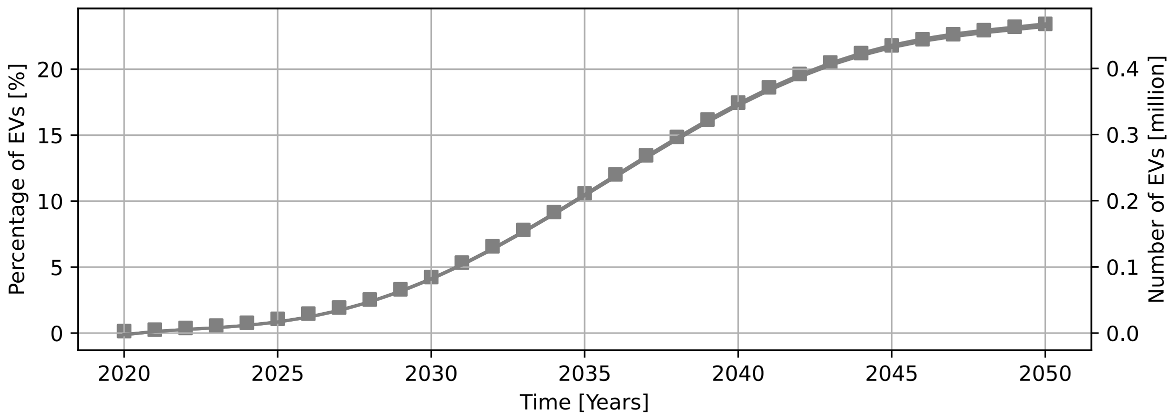


Figure 81. Estimated adoption of light-duty EVs in Puerto Rico, 2020–2050

The prediction results estimate about 4.2% adoption in 2030, 17.3% in 2040 and 23.4% in 2050. The right y-axis describes the number of EVs in millions.

This curve predicted a slower rate of light-duty EV adoption from now until 2030 followed by a faster rate of adoption between 2030 and 2040. In 2030, the percentage of light-duty vehicles that are EVs will be about 4.1% (82,116), which increases to 17.3% (346,808) in 2040 and 23.2% (467,229) in 2050.

5.3.1.2.2 Spatial Adoption Model

An estimate of light-duty EV adoption spatial diversity depended on the assessment of current and past registration data from other U.S. counties. The "EV HUB" website provides light-duty EV registration data for about 16 states.[101] This work considered 7 of the 16 states because they included at least 5 years of historical data. The states used in the assessment included: Colorado, Florida, Tennessee, New York, Wisconsin, Virginia, and Washington. These EV registration records were then combined with U.S. Census data for each county in the states[102] to identify any correlations. Using a linear correlation comparison, registered light-duty EVs corresponded well with the number of households, number of vehicles, and income with coefficients equal to 0.82, 0.85 and 0.39 respectively. The comparison with the household median income did not produce a high coefficient, but when combined or normalized with the number of drivers it proved to be a key factor in estimating light-duty EV adoptions, and a correlation coefficient of about 0.75. Correlation coefficients were not as strong for some factors like commuter travel times and gas prices.

The household income and number of drivers provided by the census were used to create a data-driven model that estimated the number of light-duty EVs in each county, or, in the case of Puerto Rico, municipalities. A Random Forest Regression model was used to model the number of light-duty EVs using the Python Scikit-learn package (Pedregosa et al. 2011),. This multidimensional model used the census data's median income and number of drivers as inputs to estimate each of Puerto Rico's municipality's light-duty EV adoptions as a percentage of the territories total. For each year in the assessment, the total number of light-duty EVs, depicted in

[101] "State EV Registration Data," Accessed July 21, 2022, https://www.atlasevhub.com/materials/state-ev-registration-data.
[102] "Census Bureau Data," Accessed July 21, 2022, https://data.census.gov/cedsci/.

Figure 81, will be multiplied by each municipality's percentage and provide the number of light-duty EVs in each municipality.

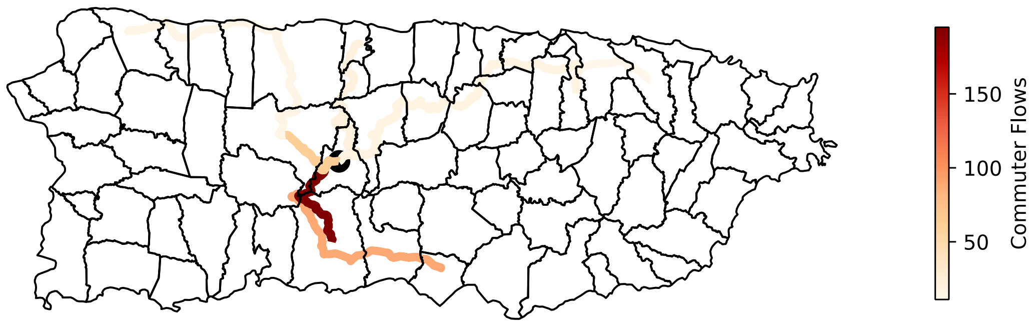
5.3.1.2.3 Estimate Light-Duty EV Energy Consumption

After estimating the number of vehicles in each region, the next step modeled the potential light-duty EV driving behaviors to determine their energy consumption and the charge location. This was accomplished by creating a likely local travel distances model. It also entailed the identification of vehicle commuter paths and their associated elevation profiles.

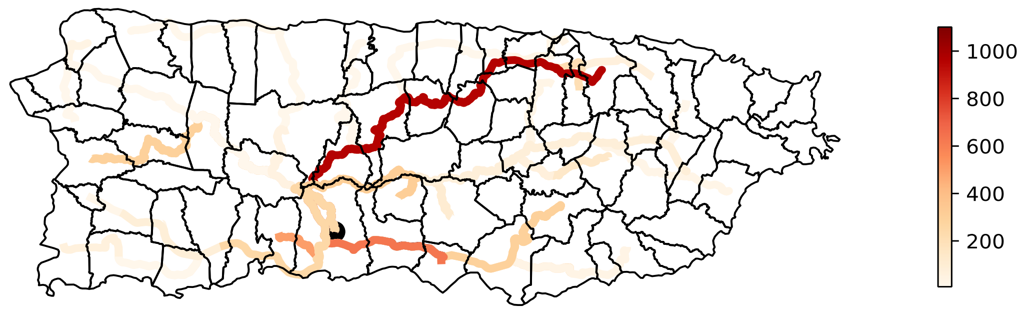
The U.S. Census provided data on the number of daily commuters traveling within or to other counties. This data was aligned with the roadway network typologies to define realistic driving distances and the elevation changes along the way. Defining these commuter travel paths involved a multistep process that began with identifying the spatial origin and destination points. Because the census data do not provide specific residence and work locations, this method assumed the commuters began and ended at the centroid of each municipality.

Between the two origin and destination county centroids, the path was defined using OpenStreetMap topology data (OpenStreetMap contributors 2017). First, the closest point on the road network to the center of the municipality was found. Then, the shortest distances between the two points were defined using the Python Networkx shortest path algorithm (Hagberg, Schult, and Swart 2008). Each of the paths from all the origin locations were created and the number of commuters was assigned to each one. Two examples of this approach in Puerto Rico are shown in Figure 82 (page 144) for source locations at Jayuya and Ponce. In each subfigure of the figure, the origin municipality is highlighted with the grey shading, and the number of commuters, or the flow of traffic to their destination, are depicted with the red shading, where the darker red indicates a larger flow of daily commuters.

An estimation of light-duty EV energy consumption involved an analysis of potential travel paths and the elevation changes along each path. For example, Figure 82 depicts the road (top map) and elevation changes (bottom graph) experienced by a driver traveling from Jayuya to Barceloneta. The distances and elevation changes were used as inputs into a model that estimated each light-duty EV's power and energy consumption.



(a) Jayuya



(b) Ponce

Figure 82. Examples of commuter paths from four locations to various destinations throughout Puerto Rico

Each of the paths are colored in red to represent the commuter flows, where the darker red paths represent more commuters than the lightly shaded paths.

The light-duty EV performance was represented using a free body diagram. This model considered the force of gravity, friction, and air resistance, as described in Equation 1 to estimate the total force required to move each vehicle.

$$F = (m)(g)sin(\alpha) + (m)(g)(C_r)cos(\alpha) + \frac{(\rho)(C_d)(A)}{2}(\nu^2) \tag{1}$$

The force (F) required to overcome gravity considered the mass (m), acceleration due to gravity (g) and the slope of the incline (α). To overcome the friction of the roadway, the equation considered m, g, α, and the coefficient of friction (C_r) equal to 0.01 for an asphalt surface. Finally, the air resistance force was estimated by considering the air density (ρ) equal to 1.225 kg/m^3, area of the front of the vehicle (A), and the vehicles velocity (ν). For this evaluation, A was assumed to be 2.341 m^2 and m was set to be 2,000 kg, which are like the specifications of a Tesla model 3 sedan thus assuming most of the light-duty EV drivers in Puerto Rico will be in sedans.

After computing the F required to move the vehicle, the power (P) was calculated by multiplying F times ν, as shown in Equation 2:

$$P = (F)(v) \tag{2}$$

The F required to move the vehicle varied along the path, but the velocity was assumed to be a constant 13.4 m/s (about 30 miles per hour).

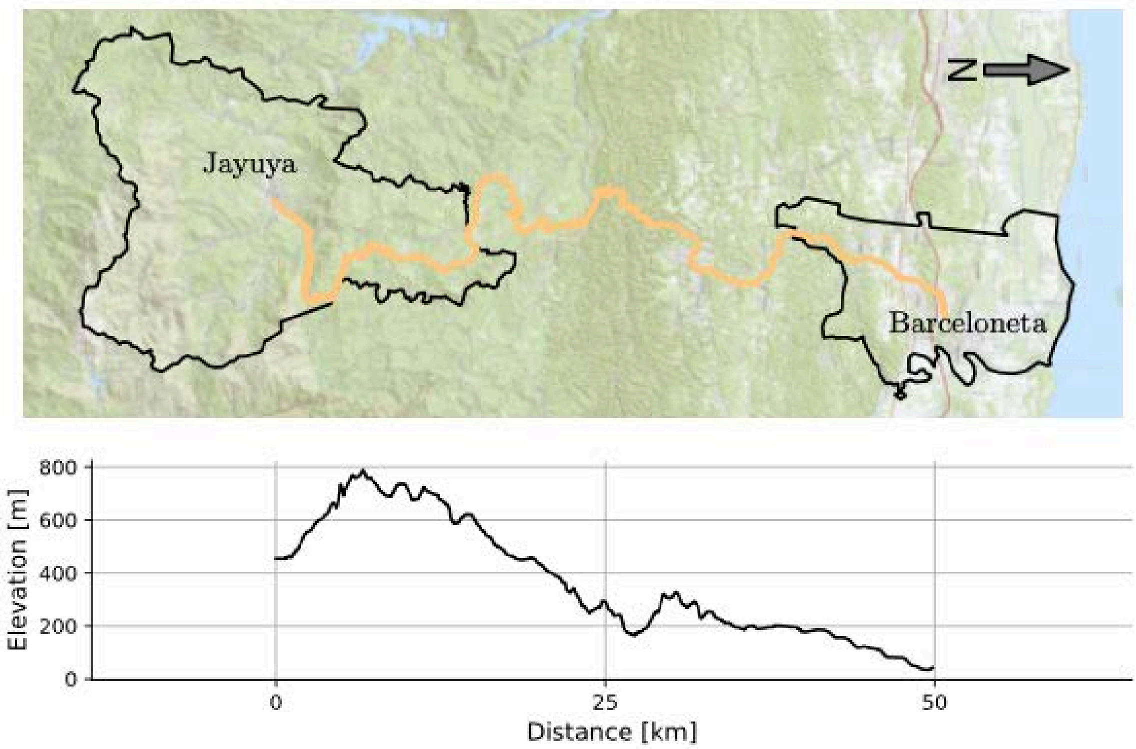


Figure 83. An example of a path between two municipalities in Puerto Rico

The roadway is shown in the top map and the elevation along the path is depicted in the bottom graph.

The simulation of all the light-duty EVs involved an iterative process, where power was computed at individual segments – straight lines in the GIS data provided by OpenStreetMap – along the route. This meant each segment included a distance and a slope that was used to compute the power consumed. The length of these segments ranged between 12 m and 298 m, and the average was 29 m. At each segment, the travel time was computed and multiplied by the power consumed to estimate the energy consumption. The total energy consumption at each destination was the integral of the consumed power along the entire path.

Estimating the local traffic paths was not as detailed as the commuter paths. Local traffic estimates were not available in existing census data. Therefore, the drive model used a stochastic approach to define the distance traveled and the energy consumed. The travel distance was determined by selecting random integers from a discrete uniform distribution in the interval (3.2 km, 128 km). The analysis also randomly defined the average efficiency of the vehicle over the total distance using a uniform distribution with a minimum of 2.4 km/kWh to a max of 5.6 km/kWh.

After computing each route's energy consumption (for both commuters and local traffic), the demand profiles at residential dwellings and at workplace locations were estimated. These profiles were based on the assumed profiles shown in Figure 84, that was used in prior work to represent two likely charging scenarios (Jones et al. 2021; Birk Jones, Vining, et al. 2022).

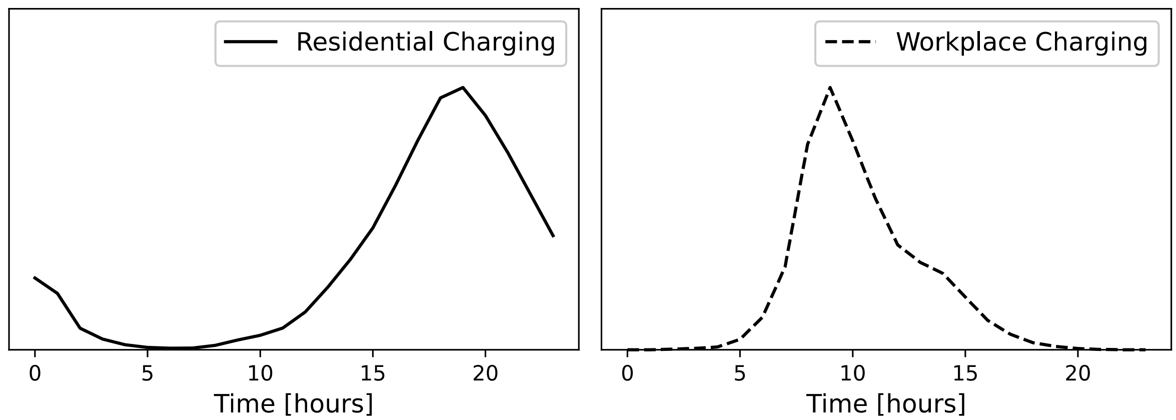


Figure 84. Two light-duty EV unmanaged charging profiles assumed to occur at residential locations (left) and places of work (right)

For residential dwellings, the profiles peak is late in the evening. The workplace charging profile's peak occurs in the morning after most people arrive at work.

The method, presented here, did not actually simulate time-series charging behaviors. Instead, the assessment modeled the magnitude of the typical unmanaged charging profiles (shown in Figure 84) that equaled the total energy consumption calculated during the light-duty EV driving simulations. This was administered using an optimization algorithm that used the quasi-Newton of Broyden, Fletcher, Goldfarb, and Shanno method (Nocedal and Wright 2006) to minimize the difference between an unmanaged charging profile and the light-duty EV energy consumption.

This assessment considered two scenarios where the availability of public charging varied. The scenarios are described as follows:

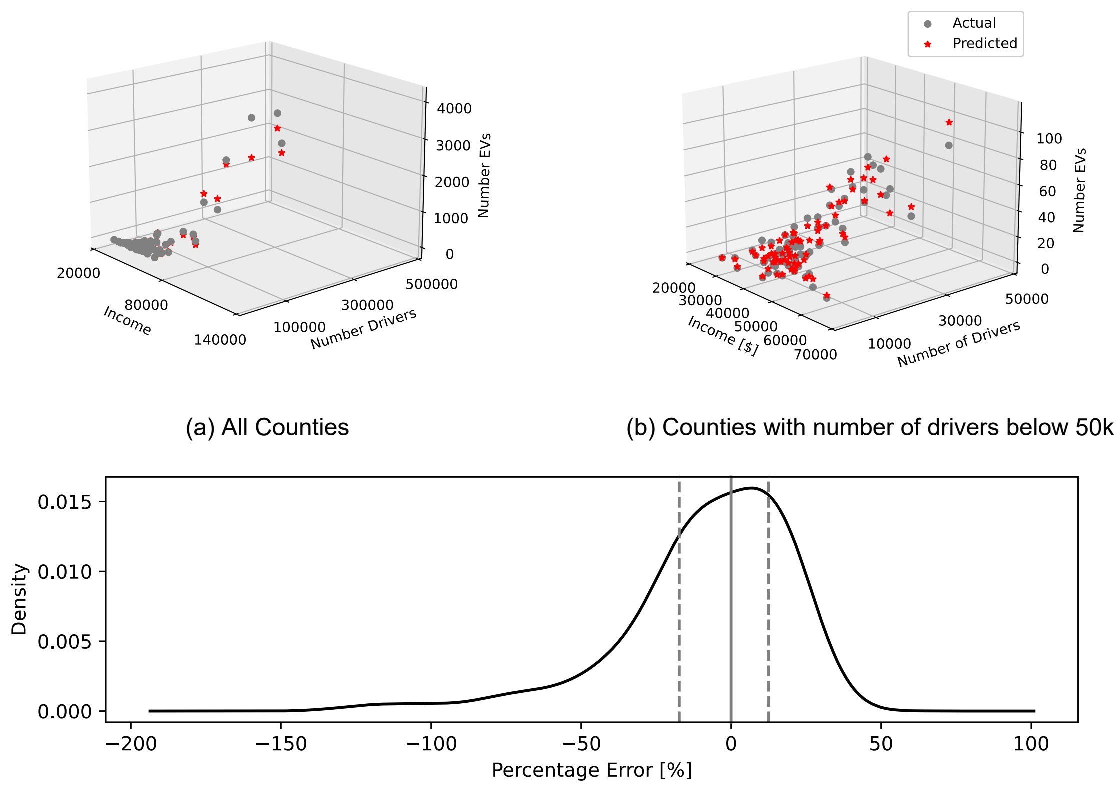
1. **Limited Public Charging:** The number of charging stations in public locations at or near places of work were only available to 20% of the commuters. The remaining 80% had to charge at home.
2. **Unlimited Public Charging:** Charging stations were available to all commuters. This implies that EV drivers charged their vehicle during the day at work after making their morning commute. In the evening, after driving home, the EV drivers again plugged in and charged their vehicle.

5.3.1.3 Light-Duty EV Results

5.3.1.3.1 Spatial Model Assessment

An evaluation of the spatial model's accuracy considered the counties within six U.S. states to train and test the algorithm. Training included a total of 502 counties. Then, the algorithm was tested by presenting it with inputs (i.e., income and number of drivers) from counties within one state to predict the number of light-duty EVs in each county. In this case, the state used for testing was Tennessee, which had 95 counties.

The results, plotted in Figure 85, include a prediction of the number of light-duty EVs for each of the 95 counties. Figure 85a compares the predicted values with the actual number of light-duty EVs for all of the counties. Most of the counties had less than 50,000 drivers, and Figure 85b provides a closer look at the results in counties with less than 50,000 drivers.



(a) All Counties

(b) Counties with number of drivers below 50k

(c) Percentage error density plot

Figure 85. The top two plots (a) and (b) compare the actual versus predicted values for all the counties in (a) and for counties with drivers below 50k in (b).

The percentage error was high in some cases, but most were between -17.3% and 12.5%.

The model did not produce predictions that exactly match with the actual light-duty EV numbers. Figure 85c provides a density plot of the percentage error and shows that the median error was 0%. The upper (75%) and lower (25%) quartiles of the percentage error results were found to be -17.3% and 12.5% respectively. This indicates that most of the prediction errors were within about plus or minus 15% of zero.

5.3.1.3.2 Puerto Rico Demonstration Region

Light-Duty EV Adoption Estimates

The analysis, using the spatial model (described earlier and reviewed in the previous section) and the forecast of light-duty EV adoption for the whole territory, estimated each municipalities' light-duty EV adoptions from 2020 to 2050. Figure 86 depicts these results as the number of EVs progresses from 1,350 in 2020 all the way to 467,229 in 2050.

The growth rate of registered light-duty EVs remained constant spatially across Puerto Rico. This consistent change in light-duty EVs was attributed to the time-series model assumptions, which used a single adoption curve for the entire island. This meant that places like the San Juan metropolitan area, located in the northeast quadrant of the main island, consistently had the greatest number of registered light-duty EVs. This was also because the San Juan area has the greatest number of total registered vehicles.

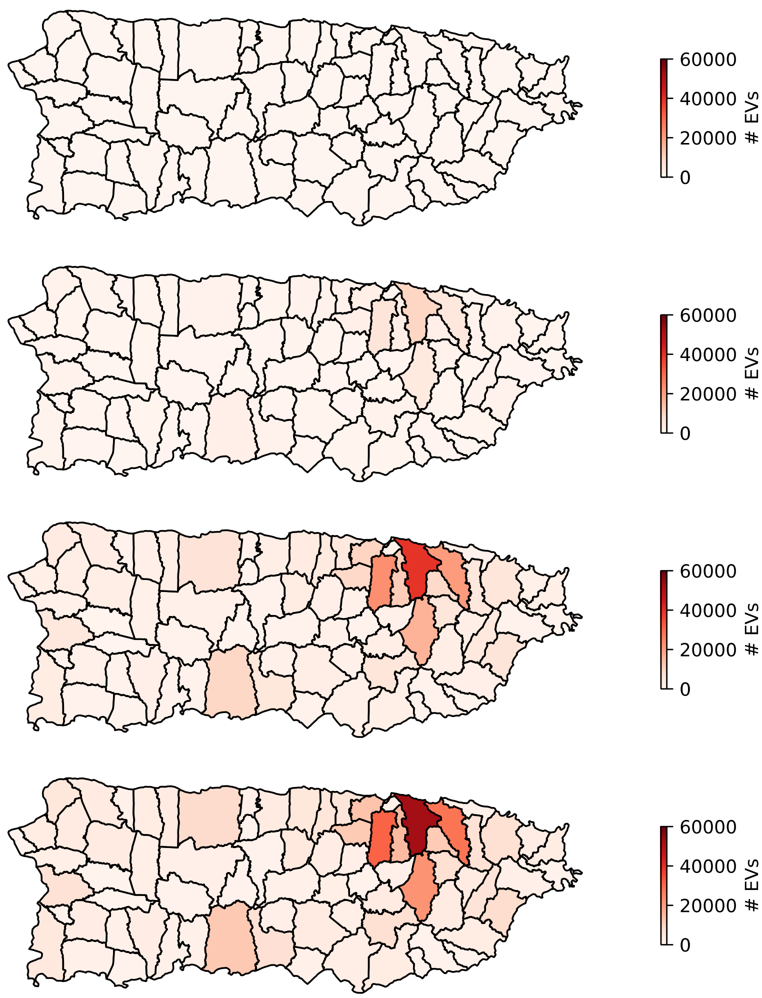


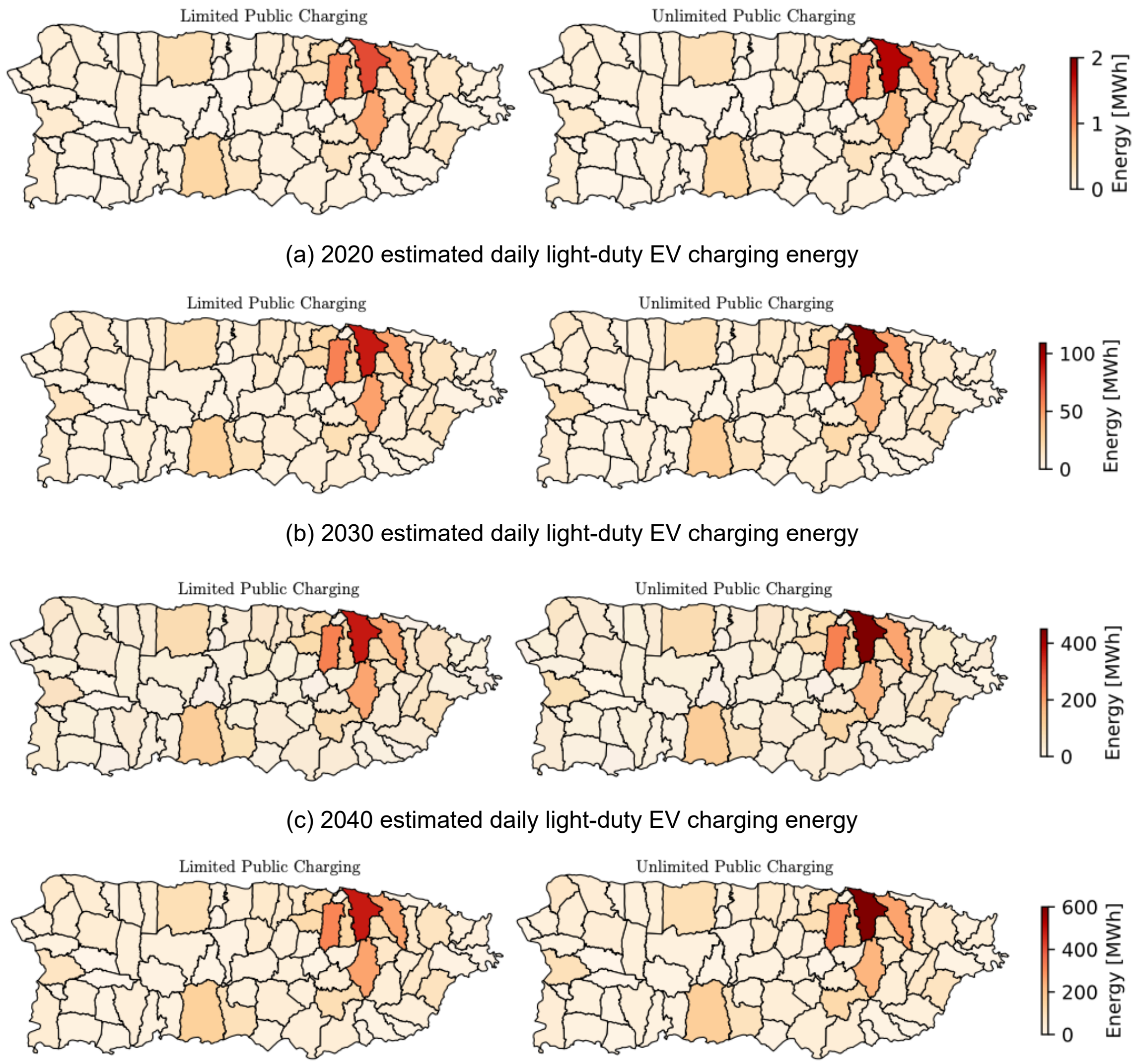
Figure 86. Light-duty EV Adoption progression from 1,350 in 2020 to 467,229 in 2050

Most light-duty EVs registered were in the San Juan Metro region. The variation in red legend refers to the number of light-duty EVs in each municipality.

Light-Duty EV Energy Consumption

After estimating commuter and local traffic travel patterns, the road elevations, and the power consumed along each path, the total daily energy usage for all light-duty EVs was estimated at each year from 2020 to 2050. Figure 88 (page 152) provides an overview of the potential average daily energy in each municipality for 2020, 2030, 2040, and 2050 adoption levels for the two different charging scenarios. Although the total island's energy consumption was the same for each scenario, the spatial variation in energy varied because all commuters charged in different locations under the unlimited public charging scenario and most charged at the same location for the limited public charging case.

The first scenario, depicted on the left maps of Figure 87, represented the case where a small number of public charging stations was available to drivers commuting to work. This meant that commuters had to wait until they got home at the end of the day to charge their vehicle. Thus, requiring more time to reach a full state of charge using Level 1 or 2 size charging stations at their places of residence and not in commercial areas. The lack of public (or workplace) charging had a noticeable impact on the energy consumption spatially; the limited public charging scenario had a more distributed energy consumption throughout Puerto Rico and was not as concentrated in areas with significant places of work in comparison to the unlimited public charging scenario, for example, the San Juan metropolitan region.



(a) 2020 estimated daily light-duty EV charging energy

(b) 2030 estimated daily light-duty EV charging energy

(c) 2040 estimated daily light-duty EV charging energy

(d) 2050 estimated daily light-duty EV charging energy

Figure 87. Maps showing the estimated daily energy consumption for each municipality from 2020 to 2050 under the limited and unlimited public charging scenarios

The second scenario, shown using the maps on the right side of Figure 87, assumed in addition to residential charging, level 2 charging stations were available at places of work. This allowed for the commuting light-duty EV drivers to plug-in while they were working and recoup the energy consumed during their morning commute. Then, the commuters would drive home after work and use their residential charging station to bring their battery back up to a full state of charge after consuming energy on their drive home. In this case, the light-duty EV charging energy was more significant in urban areas where many people work and commute to and from outside municipalities.

Both scenarios assumed local traffic, for entertainment, shopping, or other purposes, occurred with the same assumptions described earlier in the methodology section. And all local traffic used residential chargers when they returned home from their drives.

Over the 30-yr period (2020–2050), the overall daily modeled energy consumption rose from 12,812 kWh in 2020, to 855,309 kWh in 2030, to 3,484,042 kWh in 2040, to 4,670,080 kWh in 2050 for each of the two scenarios. In this simulation, the commuters consumed about 42% of the daily energy, the rest was due to local (or non-work-related driving).

Light-Duty EV Charge Profiles

An overview of the Puerto Rico's estimated power demand is depicted in Figure 88 heat maps. The figure shows the demand results for all of Puerto Rico's municipalities for a single day under 2040 adoption levels. As indicated in the sample profile discussion above, San Juan has the highest light-duty EV charging demand for both scenarios. For San Juan, the 2040 peak demand was estimated to reach 53.49 MW and 38.42 MW for unlimited public charging and the limited public charging scenarios respectively. Other regions, like Bayamon, Caguas, and Carolina also had high light-duty EV charging demand over a 24-hr period. None of the other municipalities had as significant of a change in the daytime charging under the unlimited public charging versus the limited public charging as San Juan exhibited.

(a) Limited Public Charging

(b) Unlimited Public Charging

Figure 88. Charging profile heat maps for unlimited public charging (a) and limited public charging (b) by hour of the day for each municipality at 2040 adoption levels

The two light-duty EV charging scenarios considered the same number of EVs and the same travel paths. However, the charging locations varied because of the significant number of people charging during the day while at work under the unlimited public charging scenario. San Juan, for example, experienced its highest demand during the day when public charging was available. Having public charging for all commuters reduced the evening peak. Without public charging options, the peak demand in San Juan was around hour 19. Other municipalities did not experience such a change in the time of day for the peak demand because of the number of commuters traveling from other municipalities and thus significant distances were not as great.

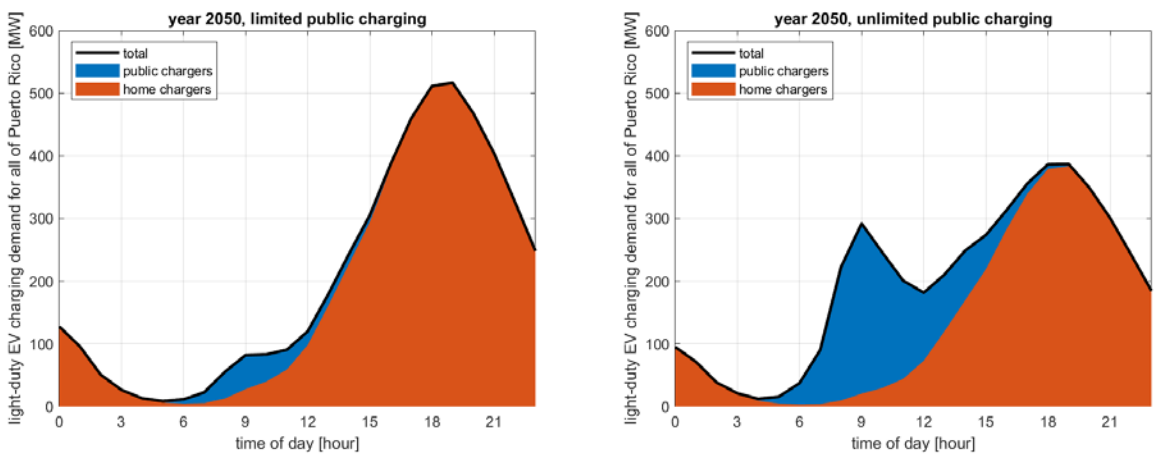


Figure 89. Puerto Rico's daily load will increase significantly by 2050, but the profile might vary depending on the availability of public charging infrastructure.

The left plot shows that the limited public charging case only has a small amount of public, daytime charging and therefore a higher demand in the evening hours. The right plot shows that with unlimited public charging including workplace charging, a significant portion of the light-duty EV demand will be accommodated for during the daylight hours.

Puerto Rico's load will likely increase significantly due to light-duty EV demands, as indicated by Figure 89. In 2050, this analysis suggests that the EVs will demand close to 400 MW if significant workplace charging stations are available. Or, in 2050, the peak will be greater than 500 MW if most of the light-duty EV charging is done at home.

5.3.1.4 Light-Duty EV Conclusion

This analysis found that light-duty EV adoptions will rise from around 1,350 in 2020 to 467,229 in 2050. Of course, this rate of increase in adoptions depends on many unknown factors, such as market availability, government incentives, and more. Furthermore, the spatial adoption of EVs will likely follow the above prediction and coincide with income levels and the number of vehicles currently used in each municipality.

The location of power consumption necessary to charge the vehicles will vary depending on the availability of charging stations. Limited public charging will result in more distributed power consumption in residential areas outside of the urban locations but will result in a very high evening peak charging load which is coincident with the system peak. Providing sufficient workplace charging can result in more energy consumption at urban locations during the day. This has multiple benefits: (1) it does not add to an existing and potential high evening peak and

(2) the demand corresponds better with solar photovoltaic (PV) electric production, which is and will be a common power source in Puerto Rico and other places in the continental United States.

5.3.2 Medium- and Heavy-Duty EVs

In this subsection, we describe the analytical process of estimating the magnitude and temporal characteristics of electric loads that may result from charging medium- and heavy-duty EVs (MHDEVs) given how they may be adopted, over time. This subsection distinguishes between legacy medium- and heavy-duty vehicles (MHDVs), those which require petroleum-based fuels to operate, and those that have been electrified (e.g., MHDEVs) to explain the analytical process. A report with full details will be available in Moog et al. (forthcoming).

The process involves estimating where and how often the population of legacy MHDVs travels in Puerto Rico. Then, the amount and geographical distribution of energy required to charge the MHDEV population is determined assuming a portion of the legacy MHDV population would be gradually replaced by their electrified counterparts. The adoption trend of MHDEVs is assumed to follow an S-curve, based on a 5% annual replacement of existing vehicles in the fleet, with the fraction of EVs among new vehicles growing by 4% every year between 2025 and 2050. The 5% annual replacement value was chosen because there were roughly 4 million class 8 MHDVs on U.S. roads at the time of the study, and sales are fairly steady at approximately 200,000 units per year. The new MHDEV growth value of 4% per year is a reasonably conservative estimate based on the fact that many states and other countries will ban internal combustion engine vehicles by 2040. Charging schedules for the different end uses of MHDEVs are then applied to driving patterns to construct electric load shapes.

We estimated that by 2050, EVs may constitute approximately 50% of MHDVs in Puerto Rico (see Section 5.3.2.2). We also estimated that the resulting electrical demand curve is lower during the daytime and higher in the evening. In a solar-energy-based electrical system with significant daytime generation, this may create challenges unless this energy imbalance is appropriately managed either on the demand or supply side.

In the process of producing these estimates, we obtained data from a variety of sources and made several assumptions to fill gaps where data were not available. We used contiguous United States data in cases where data specific to Puerto Rico were not available and scaled the data to Puerto Rico based on population and economic statistics. Consequently, although we believe that the estimates provided are defensible and provide appropriate bounds for the expected increase in electric load, the accuracy of the predicted loads' growth and their geographic distribution and hourly shapes is difficult to quantify without an in-depth statistical analysis, which is outside the scope of this analysis.

5.3.2.1 Medium- and Heavy-Duty Vehicle Use Cases

We used MHDVs in a wide range of applications, including commercial and industrial services, public services, and infrastructure maintenance. Many kinds of MHDVs exist with different expected travel patterns and widely varying use cases (e.g., long-distance transport of goods versus emergency management) that can therefore affect estimates of electric load because of charging in ways that are not immediately obvious.

MHDVs are classified by the U.S. Environmental Protection Agency (EPA) into eight classes ranked by increasing weight: 2b, 3, 4, 5, 6, 7, 8a, and 8b (Figure 90). For this analysis, Classes 8a and 8b are grouped into a single class: Class 8.

Gross Vehicle Weight Rating (lbs)	EPA Emissions Classification			
	Heavy Duty Vehicle and Engines			Light Duty Vehicles
	H.D. Trucks	H.D. Engines	General Trucks	Passenger Vehicles
<6,000 6,000	Light Duty Truck 1 & 2 <6,000 lbs	Light Light Duty Trucks <6,000 lbs	Light Duty Trucks < 8500 lbs	Light Duty Vehicle < 8500 lbs
8,500	Light Duty Truck 3 & 4 6,001–8,500 lbs	Heavy Light Duty Trucks 6,001-8,500 lbs		
10,000	Heavy Duty Vehicle 2b 8,501–10,000 lbs	Light Heavy Duty Engines 8,501 lbs–19,500 lbs	Heavy Duty Vehicle Heavy Duty Engine >8,500 lbs	Medium Duty Passenger Vehicle 8,501–10,000 lbs
14,000	Heavy Duty Vehicle 3 10,001–14,000 lbs			
16,000	Heavy Duty Vehicle 4 14,001–16,000 lbs			
19,500	Heavy Duty Vehicle 5 16,001–19,500 lbs			
26,000	Heavy Duty Vehicle 6 19,501–26,000 lbs	Medium Heavy Duty Engines 19,501–33,000 lbs		
33,000	Heavy Duty Vehicle 7 26,001–33,000 lbs			
60,000	Heavy Duty Vehicle 8a 33,001–60,000 lbs	Heavy Heavy Duty Engines Urban Bus >33,001		
>60,000	Heavy Duty Vehicle 8b >60,001			

Figure 90. EPA MHDV classification

Source: "Vehicle Weight Classes & Categories," DOE Alternative Fuels Data Center, https://afdc.energy.gov/data/10380

Although uses may vary locally because of geography, culture, and economy, in general MHDVs are used for the following purposes (Lindsey et al. 2021): (1) transport of people, goods, materials, and so on, (2) services including road maintenance, electric power system maintenance, garbage removal, medical services, fire trucks, waterworks, contractors, and construction, and (3) emergency management such as debris removal, emergency transport, fire, policing, and crowd control.

5.3.2.2 Summary of Medium- and Heavy-Duty Vehicle Load Estimation Methodology

At a high level, the technical analysis modeled the transport of imported and exported goods across Puerto Rico as a reasonable proxy for geographical distribution of MHDV uses. MHDV travel was modeled between the main island and Vieques and Culebra because Vieques and Culebra contain stand-alone census block groups. No other islands were included because they were part of other census block groups. Travel to Vieques and Culebra was assumed to be over land for simplicity despite the fact that maritime travel would be required. The geographic distribution of MHDV use associated with the transportation of goods is expected to be proportional to the distribution of use for the other purposes listed previously. The focus on goods transportation as a proxy for all MHDV use was selected because of the availability of the data (U.S. Census Bureau 2023a).

A model of goods transport across Puerto Rico was created and combined with vehicle weight estimates for each class, from which electric load estimations were computed to estimate the MHDEV charging demand. Following this, a model of MHDEV adoption over time was applied to estimate the growth of the charging load as MHDEV adoption increases. Based on these distances and the number of trips, the distribution of energy demand for intra-island transport of imported and exported goods is determined. Distribution of imported goods was used as a proxy for the spatial distribution of MHDEVs generally for all purposes across the territory.

The sequence of four stages that underpinned the technical analysis is shown in the leftmost column in Figure 91 (page 157) through Figure 94 (page 160). Each stage relied on extant data sources to compute results and inform assumptions. The four stages were as follows:

1. **Goods and Weight Allocation:** Figure 91 shows the process used to determine the number of trips, by vehicle class, required to transport goods between the Port of San Juan and census block groups (CBGs), via notional depots located at population centers at each municipality. The primary aim of this stage was to determine the spatial distribution and mass of goods imported and exported from Puerto Rico. These results were then used to determine spatial demand for vehicle trips and therefore charging demand across the Commonwealth. This stage comprised the following steps:
    A. Determine mass of imported and exported goods.
    B. Assign imported and exported goods by weight according to population across Puerto Rico at the census block resolution.
    C. Allocate the weight of the goods to vehicles by class.
    D. Determine number and origin-destination pairs for trips by vehicle class.
2. **Depot Siting and Distance Calculations:** Figure 92 presents the process to compute the distances between the Port of San Juan and population centers at each municipality and between population centers and CBGs. The goal of this stage was to construct a transportation model to estimate distances that would be used by MHDEVs to inform charging rates as part of the load estimation. The model relied on hypothetical distribution depots placed at each municipality. This stage comprised the following steps:
    A. Site each municipality's depot in a population cluster.
    B. Determine distances between the Port of San Juan and the depots.
    C. Determine distances between the depots and the centroids of the CBGs in the associated municipalities.
    D. Estimate vehicle energy use for San Juan–depot trips and depot-CBG trips.

    Transportation of goods was assumed to occur in two stages according to the following two assumptions: Goods are transported between San Juan and each municipality depot (long-haul) using Classes 7 and 8 MHDVs, and goods are transported between the municipality depot and the final destination (short-haul) using Classes 2b, 3, 4, 5, and 6 MHDVs. Published information on MHDV fleet composition in Puerto Rico, i.e., the percentage MHDV use attributable to each vehicle class, was not available when the study was performed.

3. **Scaling to Account for Other Sectors and Model Adoption Over Time:** Two modifications to the results were applied in sequence to obtain a more realistic approximation of the evolution of MHDEV charging demand for the period of interest (Figure 93). The output from the process shown in Figure 93 is used to scale the individual energy uses calculated previously for transport of imported and exported goods to account for MHDEV use cases in other sectors and their adoption over time. This stage comprised the following steps:
    A. Use estimate of MHDV fuel use to scale results for other uses of MHDVs.
    B. Develop stock-and-flow model of adoption over time.
4. **Charging Schedule Estimation:** In Figure 94, a charging schedule for each MHDV end use is estimated based on the mission, the vehicle miles traveled are estimated for each end use, and a weight factor based on the miles traveled is associated with the charging schedule for each end use—allowing the calculation of a combined charging schedule. This stage comprised the following steps:
    A. Estimate charging schedule by end use.
    B. Estimate fraction of total energy use by end use and weight class.
    C. Develop hourly time-series estimation of fraction of total daily energy use.

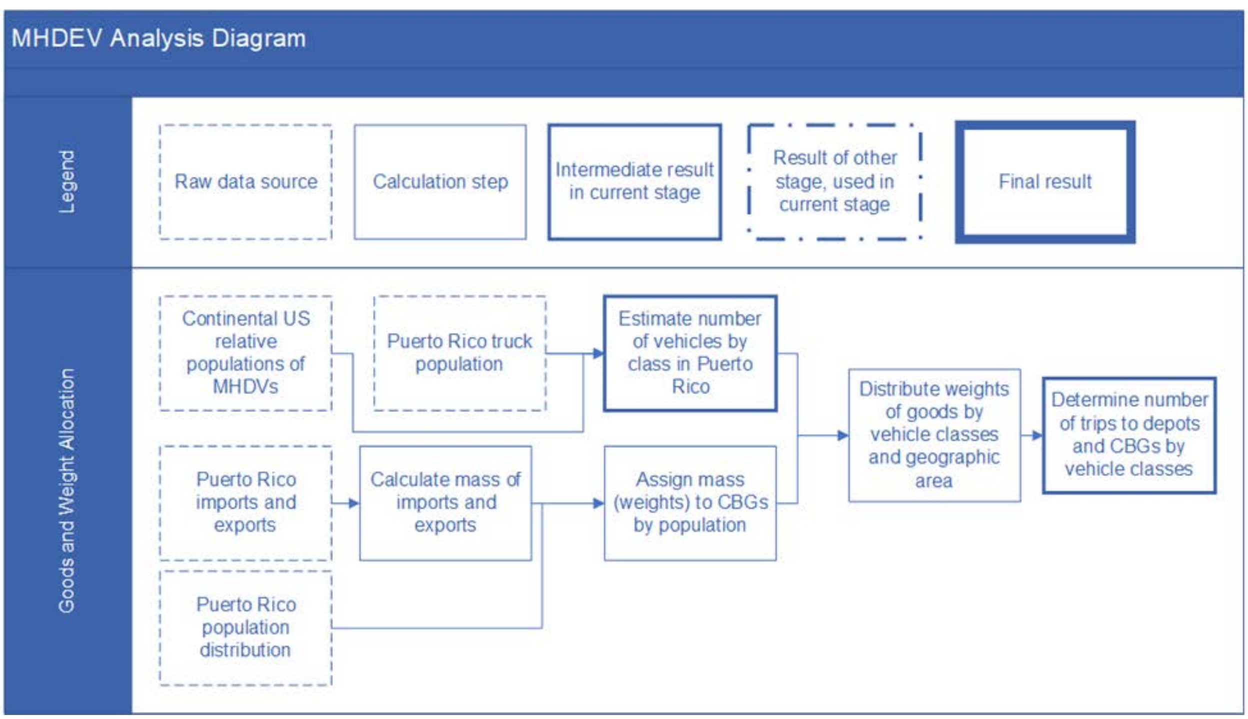


Figure 91. Partial diagram (part 1 of 4) of the analytical approach to estimate MHDEV adoption and ensuing load

Arrows indicate information flows. This step determines how goods flowing between Puerto Rico and the CONUS are allocated to vehicle classes for transfer between individual CBGs and the Port of San Juan.

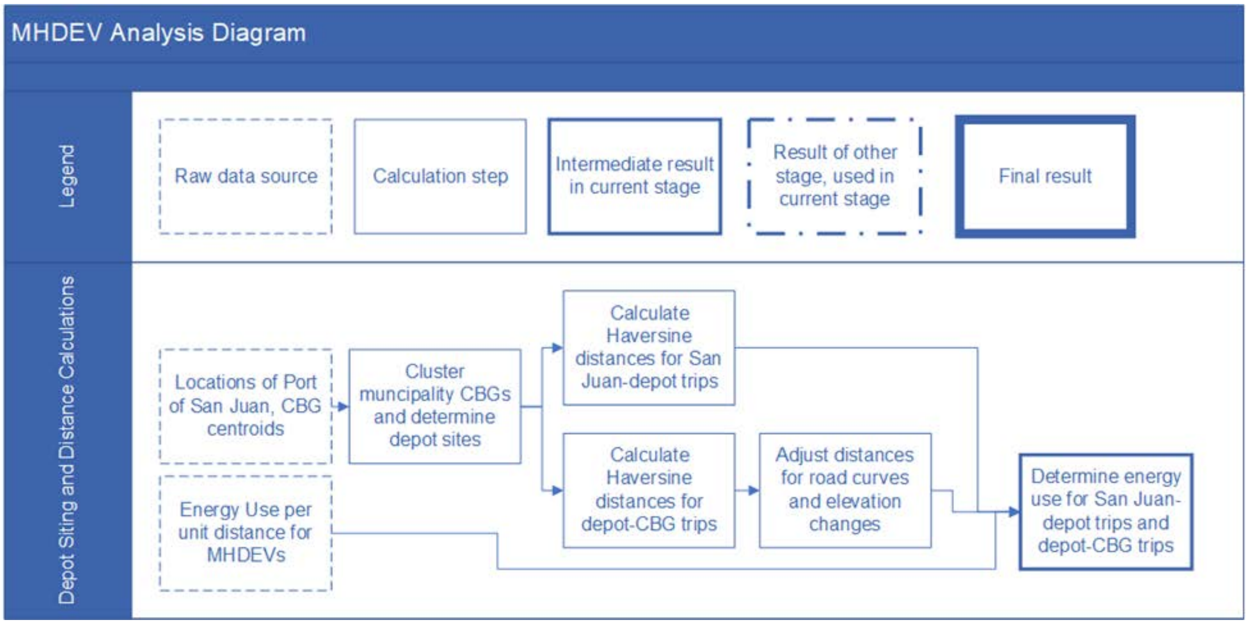


Figure 92. Partial diagram (part 2 of 4) of analytical approach used to estimate MHDEV adoption and ensuing load

Arrows indicate information flows. This step determines the distance traveled by individual MHDV classes to move goods between CBGs and the Port of San Juan, and associated energy use.

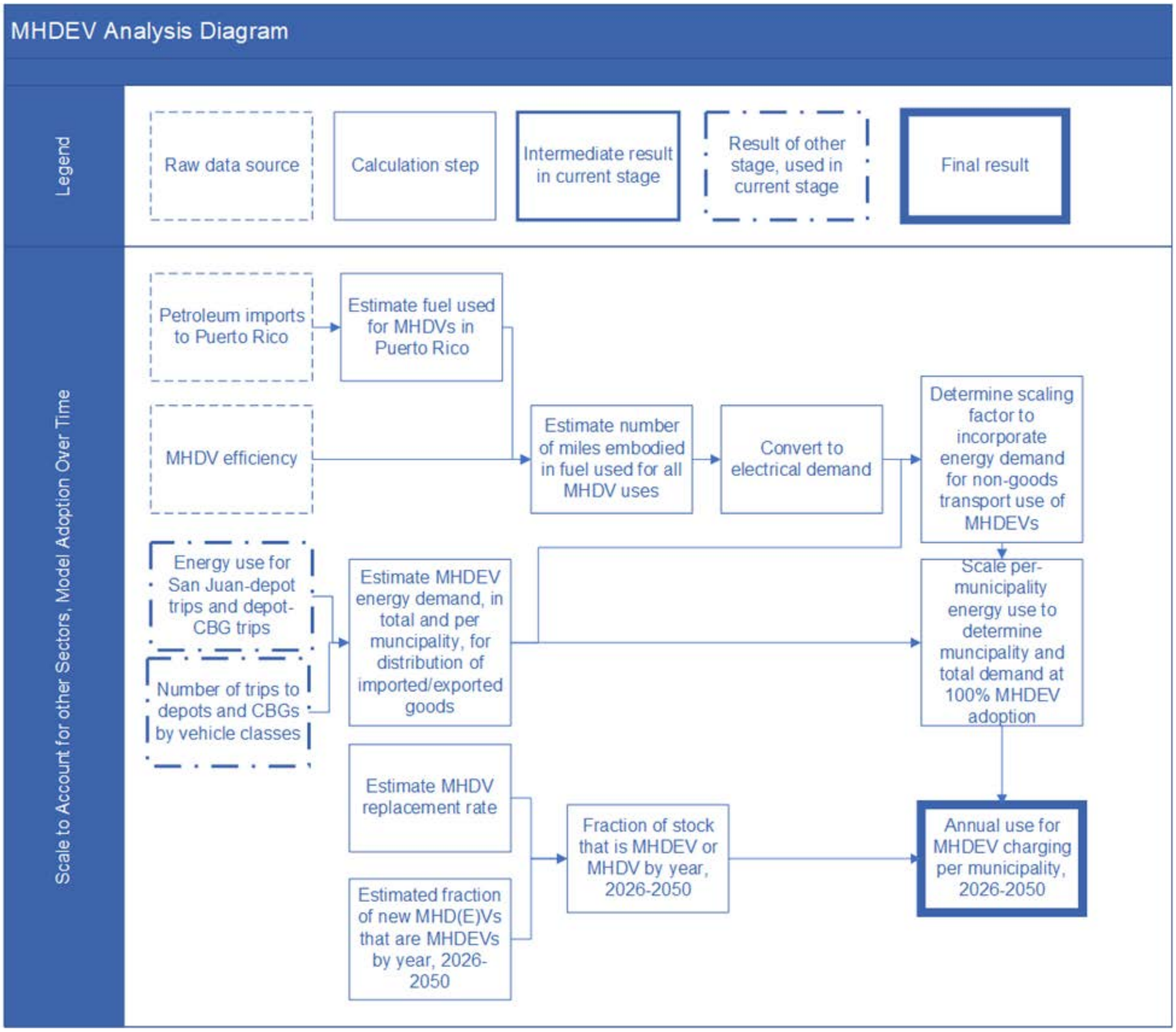


Figure 93. Partial diagram (part 3 of 4) of analytical approach used to estimate MHDEV adoption and ensuing load

Arrows indicate information flows. This step determines the overall yearly fuel consumption that can be attributed to MHDVs in 2022 and estimates the equivalent total electricity consumption by an equivalent electrified fleet.

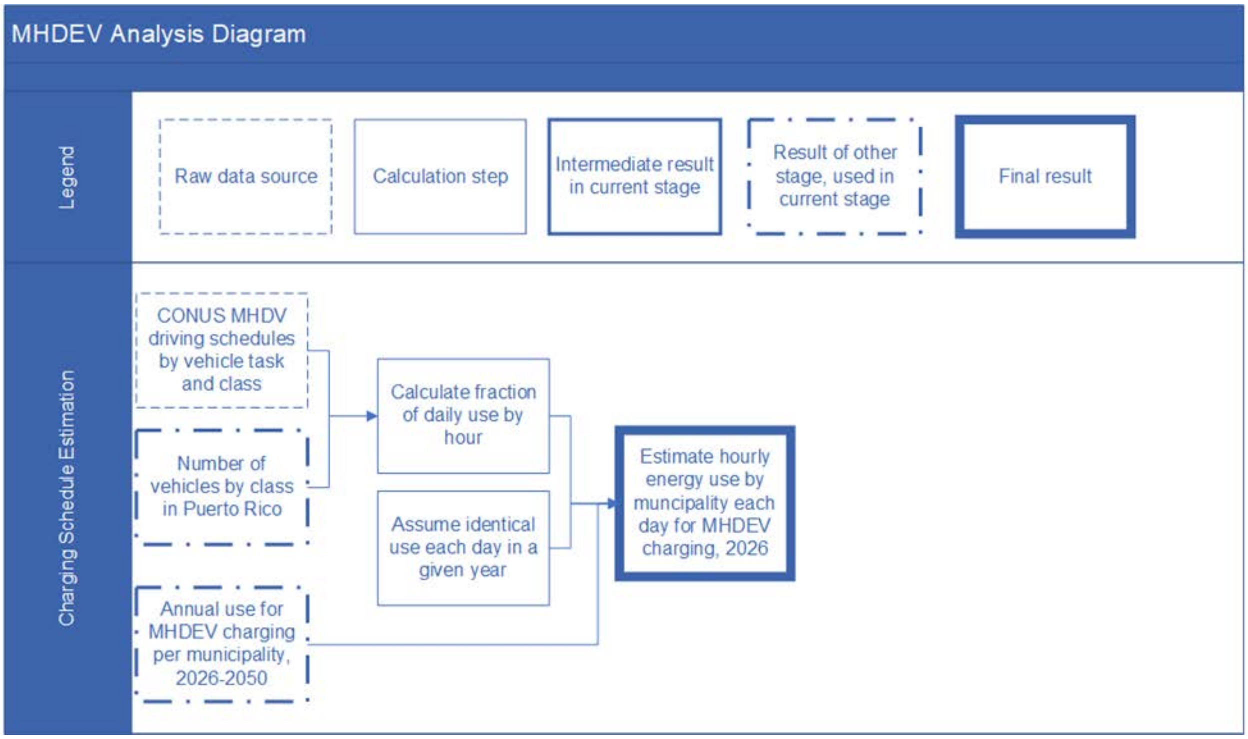


Figure 94. Partial diagram (part 4 of 4) of analytical approach used to estimate MHDEV adoption and ensuing load

Arrows indicate information flows. This step combines the hourly charging demand of vehicles with different end uses (vocations) into a total hourly charging demand for all classes.

Detailed data on the use of MHDVs, similar to the vehicle-miles-traveled data contained in the continental United States (CONUS)-based Vehicle Inventory and Use Survey (U.S. Census Bureau 2004), were unavailable for Puerto Rico at the time of this analysis. Therefore, data on the import of goods, extracted from the U.S. Census Bureau Report for U.S. Trade with Puerto Rico and U.S. Possessions (U.S. Census Bureau 2023a), were used as a proxy to estimate MHDV use in terms of miles traveled and geographic location of the travel. For this purpose, a percentage of all imported goods was assigned to each vehicle class in proportion to the total carrying capacity for the class.

Import and export of goods assumed flow between San Juan and fictional distribution centers, each located at a municipality population center, leveraging larger truck classes. The model also accounted for transport of goods from each distribution center to the final destinations, which were modeled as the geographic center of the CBGs contained in each municipality, leveraging smaller truck classes.

5.3.2.3 Estimation of Charging Schedule for Each End Use

The influence of the charging schedule for each end use on the overall load because of MHDEV charging was considered. This was accomplished by considering the vehicle miles traveled for each end use and the associated energy consumption, thereby assigning a weight to each row in Figure 95. We assumed charging would therefore fall during off-use periods for MHDEVs, where off-use periods were the same as those in CONUS for each vehicle's end use.

Figure 95. Hourly charging schedules by MHDEV use category (e.g., vehicle class and use) averaged for all vehicles within that category

Light blue indicates the MHDEV class is able to charge. Dark blue indicates a MHDEV is unable to charge (e.g., while it is being utilized).

Certain MHDEV use categories may be indicated in the figure as able to charge across all 24 hours. This is because there is no preferential vehicle usage schedule for all vehicles in those categories, during which charging would present logistical difficulties.

5.3.2.4 Conversion of Vehicle Miles Traveled to Charging Schedule

The VIUS 2002 report (U.S. Census Bureau 2004) provides the total vehicle miles traveled for each vehicle body type and weight class. Mileage estimates will be provided in the main report when it is released (Moog et al. forthcoming). Based on estimated average electricity consumption per mile traveled for individual weight classes, C_W, the total yearly electricity consumption, $E_{B,W}$, for each vehicle body type, B, and weight class, W, can be estimated using:

$$E_{B,W} = VMT_{B,W} \times C_W,$$

where $VMT_{B,W}$ indicates total yearly vehicle miles traveled for the body type and weight class. Of course, this estimate neglects that electricity consumption per mile traveled depends on several factors—including the make and model of the vehicle, the settings used (e.g., level of regenerative braking), elevation changes along the route, speed, acceleration profile, and even individual operators' driving style—that cannot be captured by an "average" electricity consumption value. As more data become available, it may become possible to improve on these estimates, but here we attempt to provide a reasonable first-order estimate.

Finally, the fraction of total energy use for each body type and weight class $f_{B,W}$ (for example, fraction of energy use by class 2b-3 "hub and spoke" delivery vans) can be determined by dividing individual energy consumption entries by the total energy use over all body types and weight classes, using:

$$f_{B,W} = \frac{E_{B,W}}{\sum_{B,W} E_{B,W}}.$$

The contribution of each vehicle body type/weight class combination, B, W, to the energy consumption of a specific end use can be obtained by mapping body type/weight class to the different end uses, for which charging schedules were estimated previously. For this mapping, we assumed the energy contribution of a specific body type/weight class to an end use is split evenly among all end uses in which the body type/weight class participates.

Therefore, for example, if body type/weight class (pickup truck/class 2b) contributes to traffic and general service and to utility service, its energy use fraction, $f_{pickup\ truck,class\ 2b}$, is split evenly between the two end uses. The sum of all contributions to a particular end use from all body types/weight class combinations (some of which may be zero) then becomes the weight that is given to the charging schedule associated with that end use. By construction, the sum of all these weights is unity.

5.3.2.5 Scaling Factor To Account for Other Transportation Sectors

The results were scaled to account for MHDEV use in all other transportation sectors. Development of the scaling factor was based on an estimate of the amount of diesel fuel consumed daily in Puerto Rico. EIA reported 8,000 barrels per day of distillate fuels in 2021.[103] Distillate fuels include diesel and oils used for heating,[104] so it was assumed all distillate fuels used in Puerto Rico are diesel. We further assumed all diesel fuel used in Puerto Rico is either for generation or transportation.

We estimated daily consumption as roughly 19,000 barrels of petroleum—whether diesel or residual fuel oil—per day. Puerto Rico imported roughly 17,000 barrels of residual fuel oil per

[103] https://www.eia.gov/state/print.php?sid=RQ
[104] https://www.eia.gov/tools/glossary/index.php?id=distillate%20fuel%20oil

day in 2021. The petroleum power plants in Puerto Rico mostly run on residual fuel oil.[105] Because residual fuel oil is generally cheaper per unit energy than diesel f, we estimated that of these 19,000 barrels of petroleum used for generation per day, all of the 17,000 barrels are used for electricity generation—leaving roughly 2,000 of diesel, corresponding to approximately 25% of imported diesel fuel. This left 75% of diesel for MHDV use.

Based on these assumptions, the daily MHDV drivetrain energy output is as follows:

$$E_{MHDV} = 6000\frac{\text{bbl}}{\text{day}} \times 42\frac{\text{gal}}{\text{bbl}} \times 3.22\frac{\text{kg}}{\text{gal}} \times 45.5\frac{\text{MJ}}{\text{kg}} \times \frac{0.25}{3.6\ \frac{\text{MJ}}{\text{kWh}}} = 2.56 \times 10^{6}\ \frac{\text{kWh}}{\text{day}}$$

The total current equivalent electricity use of 2.56E6 kWh/day equates to 32 times our estimates. Therefore, the scaling factor is 32. The scaling factor was applied to the results by multiplying it with all MHDEV charging demand estimates.

5.3.2.6 Stock-and-Flow Model To Account for MHDEV Adoption Over Time

The results were scaled to incorporate non-goods transport use of MHDVs using publicly available figures on petroleum imports and consumption for Puerto Rico and calculating estimated miles driven by MHDVs for all sectors. Estimates were then scaled a final time by the MHDEV adoption S-curve.

Electrification of the MHDEV segment in Puerto Rico was assumed to be based on how the various commercial sectors decide to invest in this technology over time. Incentives for company adoption may be significantly different from those for light-duty vehicles (LDVs), primarily owned by noncommercial entities. Notably, although the end state is known, rates of EV adoption in these sectors may be impossible to predict with any accuracy.

MHDEVs adopted over time were assumed to replace internal-combustion-powered MHDVs. For each year, a fraction of MHDVs was replaced with MHDEVs.

Stock-and-flow models are frequently used as part of system dynamics modeling (Forrester 1973, 18–19). They allow the modeling of systems that may include feedback loops and nonlinear dynamics that may be difficult to evaluate in closed form and therefore require stepped modeling. In our case, only a simple model was necessary, and it is diagrammed in Figure 96 (page 164).

The total stock of MHD(E)Vs was assumed to remain the same for the entire period of interest. Only the composition—that is, the percentage of electric versus nonelectric vehicles—would change. In each year, some fraction of vehicles was assumed to be retired, and MHDVs and MHDEVs would be retired according to their fraction of total MHD(E)V population. Retired vehicles would be replaced with MHDEVs or MHDVs according to their respective fractions. The fraction of vehicles that was MHDEVs was assumed to be 0 until 2026, and modeling began in 2026, at which point the initial fraction of MHDEVs was 0.02.

[105] https://aeepr.com/en-us/QuienesSomos/Pages/ElectricSystem.aspx

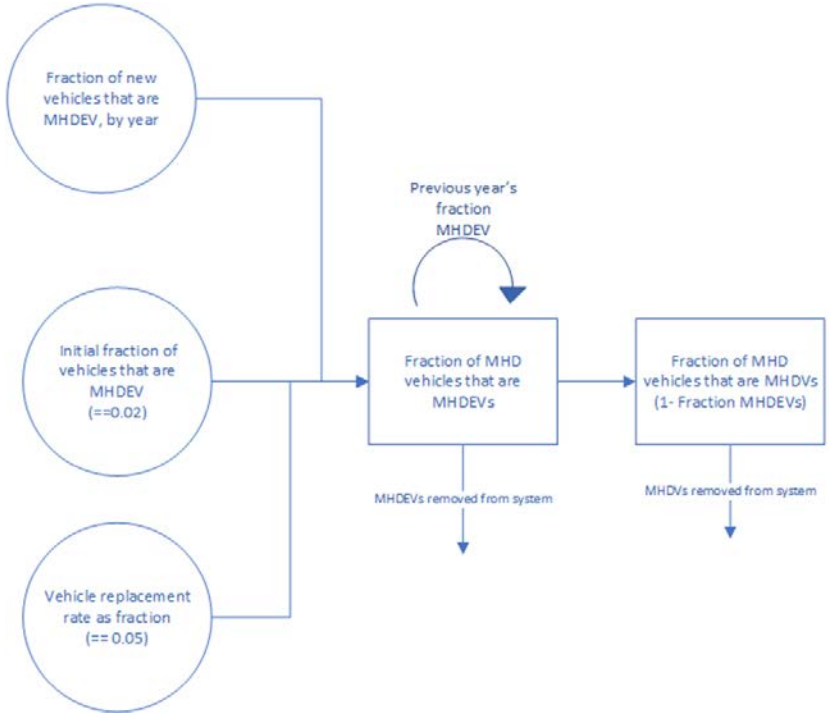


Figure 96. Stock-and-flow model diagram

Figure 97 (page 165) shows how the trend of MHDEV adoption was nonlinear over time between 2021 and 2050. A total of 47.4% of MHDVs were estimated to be electric by 2050. The assumptions used in the model were as follows:

1. No MHDEV adoption was assumed until 2026 because of vehicle cost, limited supply, and challenges in accessing or installing appropriate charging infrastructure.
2. The rate of replacement of MHDVs is approximately 5% per year. This value was chosen because there were roughly 4 million Class 8 MHDVs on U.S. roads at the time of the study, and sales are fairly steady at approximately 200,000 units per year.
3. Replacement of MHD(E)Vs does not depend directly on the age of the vehicles because other factors, such as wear and tear from intensity of use, are also involved. The assumption is that 5% of the existing fleet will be replaced each year, independently of the root cause for replacement.
4. Replacements with MHDEVs will occur with the fractions calculated for both MHDEVs and MHDVs.
5. By 2050, the expectation is that all new MHD(E)Vs in Puerto Rico will be EVs. This is a reasonably conservative estimate because in many U.S. states (California, Maryland, Connecticut, Delaware, Massachusetts, New Jersey, New York, Oregon, and Washington) and other countries (all of the EU, Great Britain, Israel, and Singapore), the sale of internal combustion engine (ICE) LDVs will be banned (or bans are planned) between 2035 and 2040, and MHDVs will not be far behind. We assume that, until then, in each year, the fraction of new vehicles sold that are EVs increases by 0.04, i.e., linearly. (This does not mean that total quantity of EVs sold also increases linearly or that the fraction of all vehicles that are EVs increases linearly.)

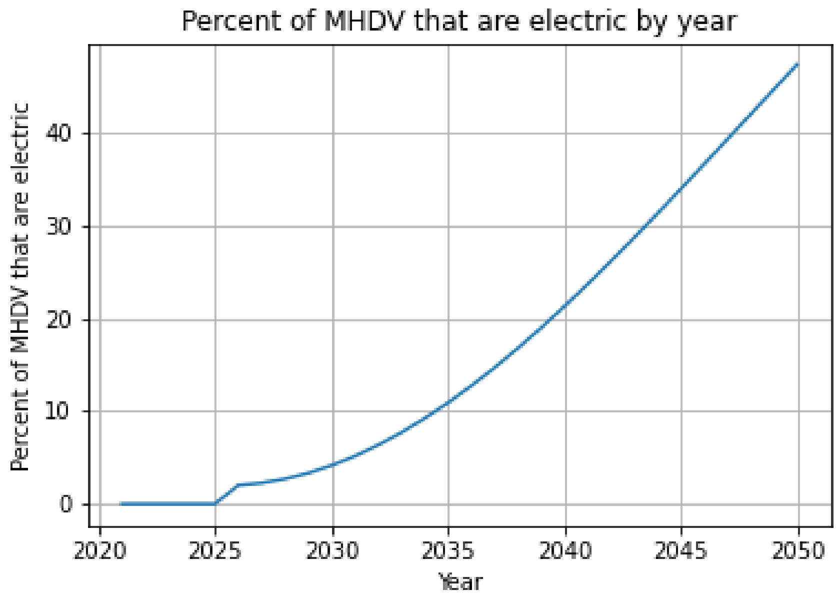


Figure 97. Fraction of electrified MHDVs, 2021–2050

The figure shows adoption only through 2050. Therefore, it is not shown that adoption would eventually level off in later years according to the assumption of an S-curve.

Figure 97 shows the assumed nonlinear trend of MHDEV adoption between 2021 and 2050. Under this trend, 47.4% of MHDVs would be electric by 2050. Therefore, if MHDVs are expected to be replaced by MHDEVs over time according to our methodology and assumptions, then it may take decades for the entire MHDV fleet to be electrified in Puerto Rico.

5.3.2.7 MHDEV Results

Energy use by municipalities on the main island for years 2023, 2030, 2040, and 2050 are shown in Figure 98.[106,107] The figure shows annual energy use (MWh) required for the population of MHDEVs determined in this study by municipality. San Juan uses the most energy because all long-haul vehicles are assumed to charge there after returning from deliveries to municipal depots. In 2023, demand in every municipality is zero because adoption is assumed to be zero that year. For comparison purposes, the total energy generation in Puerto Rico in 2021 was approximately 18,000,000 MWh (EIA n.d.-b), meaning the expected island-wide load due to MHDEV charging in 2050 of 404,734 MWh is approximately 2.25% of existing total load due to all other uses. Note that approximately half of long-haul charging takes place in San Juan municipality, making the fraction of load due to MHDV charging higher there.

Imported goods are transported from the Port of San Juan to depots located at each municipality using higher-class MHDVs, charging both at San Juan and at the municipality, and then from the depot to the destination by lower-class MHDVs, charging at the municipality. Certain municipalities, most notably San Juan, have high demand by 2050 compared to others. In the

[106] MHDEV adoption was not assumed to occur until 2025, when the PR energy was assumed to be in a better position to handle the increased load attributable to these vehicles. Therefore, energy use in 2023 is zero in all municipios.

[107] For downstream modeling, these annual values were then subdivided into 365 days of identical consumption (not shown). Weekday versus weekend demand was not considered.

case of San Juan, this is mostly attributable to the assumption that long-haul vehicles would charge before driving to the depots in all other municipalities. Other key factors that increase the energy use at a municipality include higher populations, which would require more goods and therefore more trips; a higher number CBGs in a municipality, resulting in more short-haul transportation; or farther distance from San Juan, resulting in the need for long-haul vehicles to recharge before the return trip to San Juan. The combination of two or more factors can also impact energy use at each municipality.

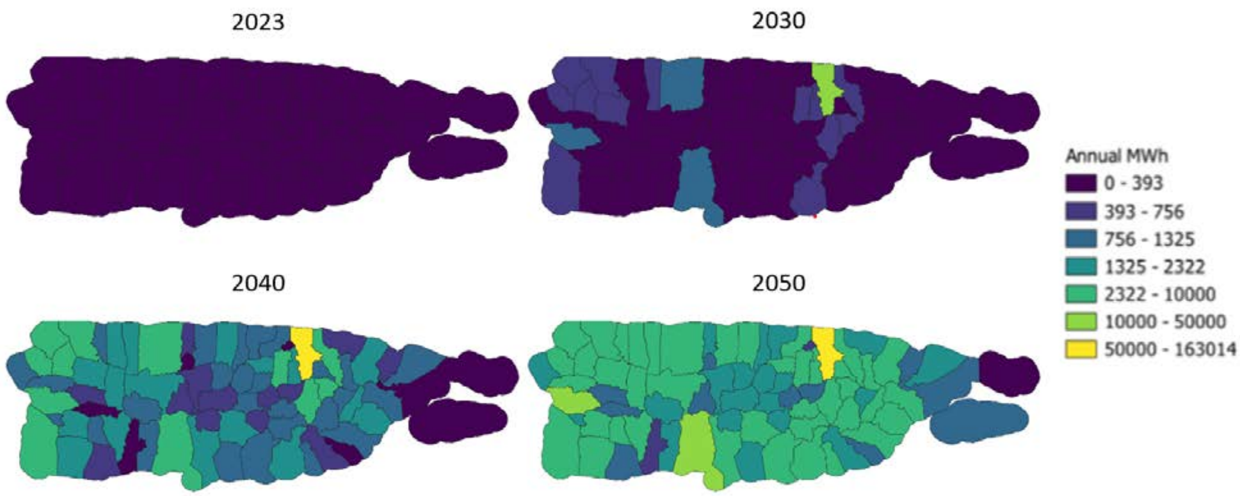


Figure 98. Annual energy use (MWh) required for the population of MHDEVs determined in this study by municipality

San Juan uses the most energy because all long-haul vehicles are assumed to make a round trip from there to all other municipalities. In 2023, demand in every municipality is zero because adoption is assumed to be zero that year.

Figure 99 (page 167) shows the estimated fraction of daily charging for the main island in Puerto Rico in each hour of the day (0–24). Charging is highest in the evening and at night, ostensibly when MHDEVs are not in use and so are able to be charging. The plateau between the hours of 18 and 21 is because of certain end uses of vehicles (e.g., shuttles, certain types of delivery, light hauling) operating during extended business hours (see Section 5.3.2.1 for additional context). It is notable that this charging pattern does not correspond well to when the sun is out and hence during times when excess photovoltaic energy production is unlikely. This analysis did not consider coordinated MHDEV charging strategies to, say, level out the charging demand pattern throughout all hours of the day.

This result follows from the explanation in prior sections on MHDV use cases for businesses today, where MHDEVs discharge their batteries primarily during daylight hours and recharge at night. While not unexpected, this result shows that MHDEV charging schedules that only follow the use of MHDEVs (i.e., that charge either when the vehicles are not in use, or when the available range has been exceeded) may present challenges for a solar-dominated energy generation system.

The shape of the curve provided in the charging schedule may be altered by providing appropriate incentives to charge during certain times, such as when generation is increased. However, a high degree of nocturnal MHDEV charging may be inevitable unless technological measures, such as stationary batteries or roadway inductive charging, are also adopted. As noted previously, it may be possible for utilities and MHDEV fleet owners to agree on recharge schedules that would offset charging to those times that benefit the bulk power system. Charging may also be shifted to preferred times of day through the use of time-of-use rate schemes and similar incentives. Future studies should consider the impacts of these measures on MHDEV charging schedules if they are implemented in Puerto Rico.

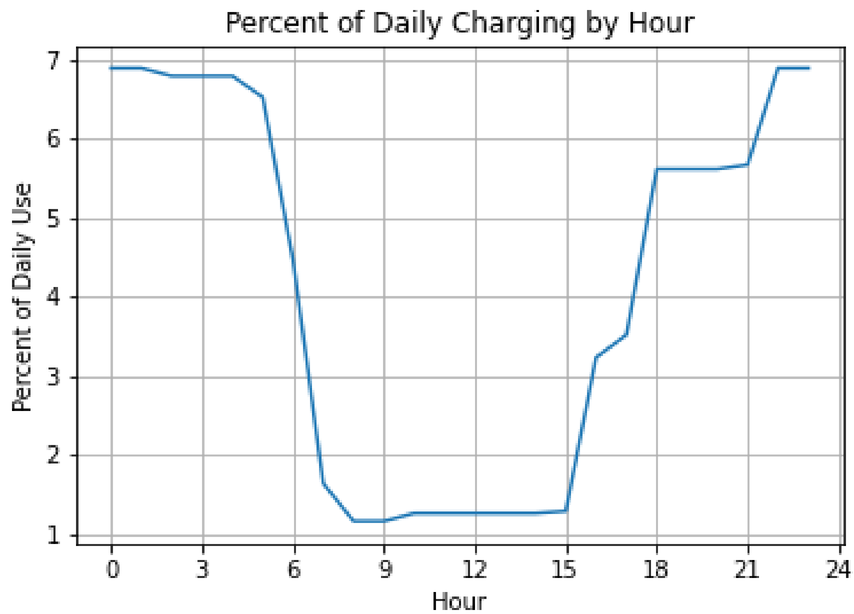


Figure 99. Percentage of the total estimated daily charging energy for all MHDEVs in each hour of a 24-hr period starting at midnight (e.g., hour 0)

Charging was estimated to be higher in the evening and at night rather than during the day.

5.3.2.8 MHDEV Considerations

A major assumption that underpinned the methodology was that the use of MHDVs in Puerto Rico would mirror the use of MHDVs in all economic sectors of CONUS. This assumption enabled the incorporation of data to break down the percentage of MHDVs used in CONUS by vehicle class (Lowell and Culkin 2021) and apply that percentage to Puerto Rico, which is not necessarily accurate. Ultimately, the number of MHDVs used in Puerto Rico was assumed to be equivalent to the same number of MHDEVs for all use cases in this analysis.

Import and export of goods assumed flow between San Juan and fictional distribution centers, each located at a municipality population center, leveraging larger truck classes. This is a highly simplified model and may not accurately estimate actual movement of goods and services across Puerto Rico.

Energy use per unit distance for trips was used to determine the per-trip energy requirements for each class of vehicle. To the best of our knowledge, published information on energy consumption rates for existing MHDEVs didn't exist when the study was performed. Knowing the carrying capacity of each class of vehicle allowed the calculation of total energy requirements across the model in the limiting case of a fully electrified MHDV fleet.

These results were then scaled to incorporate non-goods-transport use of MHDVs using publicly available figures on petroleum imports and consumption for Puerto Rico and calculating estimated miles driven by MHDVs for all sectors. Estimates were then scaled a final time by the MHDEV adoption S-curve. The application of multiple scaling factors, and the simplified adoption curve, may impact the reliability of the geospatial MHDEV charging estimates.

Legacy MHDVs are tools for performing many kinds of work, with routines that are generally unconstrained by refueling stops, which are short in duration and can be performed at a vast network of fueling stations. MHDEV operators would likely resist changing their mission schedules because of charging needs (Al-Hanahi et al. 2021). Electric loads of MHDEV charging in Puerto Rico may differ from modeled load shapes based on CONUS data, which may introduce both additional challenges and opportunities.

The U.S. Census Bureau Vehicle Inventory and Use Survey (VIUS) 2002 data set (U.S. Census Bureau 2004) was used for this analysis. VIUS 2022—the newest version of the survey since 2002—was unavailable at the time of this analysis and will contain information specific to Puerto Rico on its release. This data source along with others that may be released over time could allow for improved charging schedule estimates.

For the above-mentioned reasons, results from this charging schedule study should be treated as a starting point to consider how the MHDEV fleet in Puerto Rico could interact with electric power infrastructure.

5.4 Results

5.4.1 Electricity Sales to Electric Load Conversion Results

We created the final electricity sales projections from FY23–FY51, disaggregated by sector and region, by combining the projections for end-use loads (Section 5.1, page 119), energy efficiency (Section 5.2, page 124), and EVs (Section 5.3, page 138). These sales projections were used in other PR100 activities such as forecasting the adoption of distributed energy resources and conducting an economic impact analysis. Other PR100 activities required projections for electric load (i.e., the amount of generation needed to meet demand, accounting for losses and other factors), such as utility-scale capacity expansion modeling.

According to the 2019 IRP, total electric load consists of total electricity sales from all sectors, technical losses, nontechnical losses, auxiliary loads, and PREPA's own use. The PR100 projections also apply losses, auxiliary load, and PREPA's own electricity consumption to the final sales projections to develop final electric load projections. The details on the assumptions used for losses, auxiliary load, and PREPA's own use can be found in Section 5.1.1.5.

5.4.2 Electric Load Variations: Mid Case and Stress

PR100 developed two primary electric load variations that were passed to downstream modeling tasks and combined with land use variations and three scenarios of distributed PV deployment (i.e., distributed energy resource adoption modeling [Section 7, page 186], utility-scale capacity expansion modeling [Section 8, page 209], and so on): a Mid case and a Stress variation. The details of each load variation are contained in Table 21.

Table 21. Description of Mid case and Stress Electric Load Variations

Component	Mid case Variation	Stress Variation
End-Use Loads	Mid case	Stress
Energy Efficiency	Act 17 Goals	Act 17 Goals
EVs	Sufficient Workplace Charging	Insufficient Workplace Charging

The breakdown of the Mid case load projection is displayed in Figure 100. It shows the Mid case end-use loads only, the Mid case end-use loads combined with the energy efficiency projection, and the Mid case end-use loads combined with both the energy efficiency and EV projections. A similar breakdown of the Stress variation load projection is displayed in Figure 101. The overall Mid case and Stress variation projections are compared in Figure 102. The percentage breakdowns for each sector's contribution to the overall Mid case and Stress variation projections are shown in Figure 103 and Figure 104, respectively.

Based on LUMA data, total electricity sales for Puerto Rico were 16,282 GWh in FY22. In the Mid case variation, sales decline to 14,240 GWh in FY30 and to 13,192 GWh in FY51, with EVs accounting for 2% of sales in FY30 and 16% of sales in FY51.

In the Stress variation, sales rise to 16,537 GWh in FY30 and to 18,422 GWh in FY51, with EVs accounting for 2% of sales in FY30 and 12% of sales in FY51. Total EV sales are slightly higher in FY51 in the Stress variation; however, EV sales account for a lower percentage of total sales in FY51 compared to the Mid case variation because end-use loads are significantly higher in the Stress variation.

These two variations were created (as discussed in Section 8) due to concerns from stakeholders that current projections of population and economic factors used in the end-use load projections were uncertain. Therefore, a consideration for the future would be to monitor the actual end-use load trajectory against what has been forecasted here as well as ongoing changes to population and economic forecasts. Into the future, analysis of the end-use loads could help position reality within the various scenario results in this report.

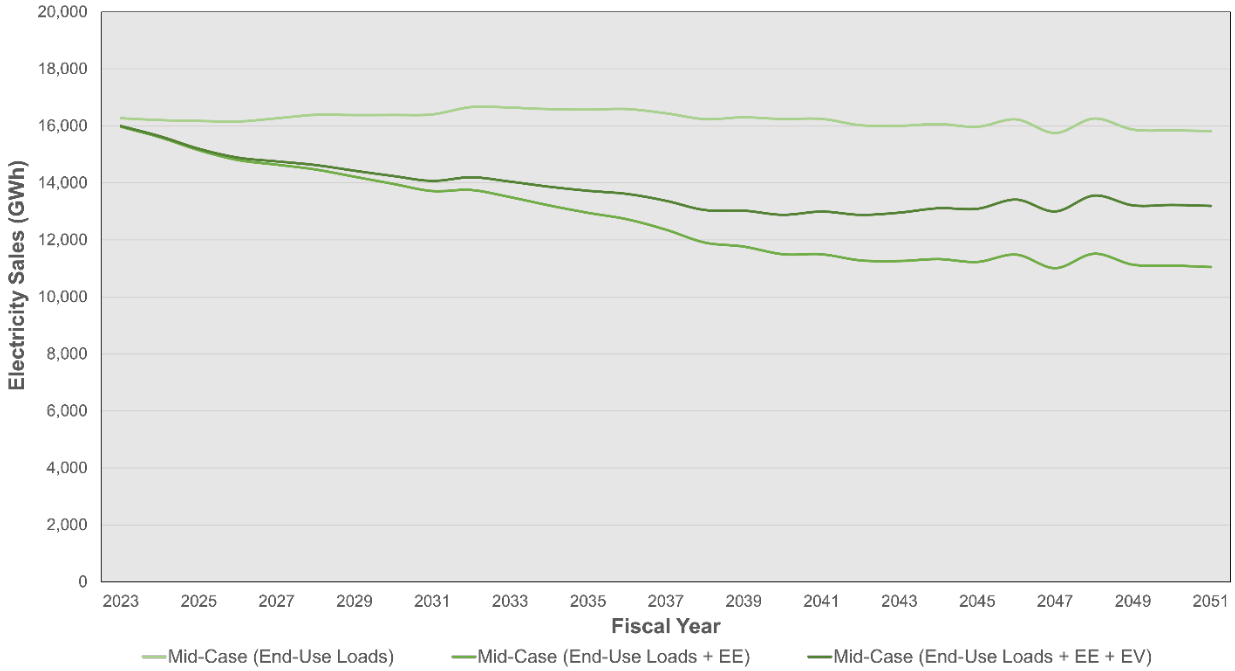


Figure 100. Electric load projections: Mid case variation, FY23–FY51

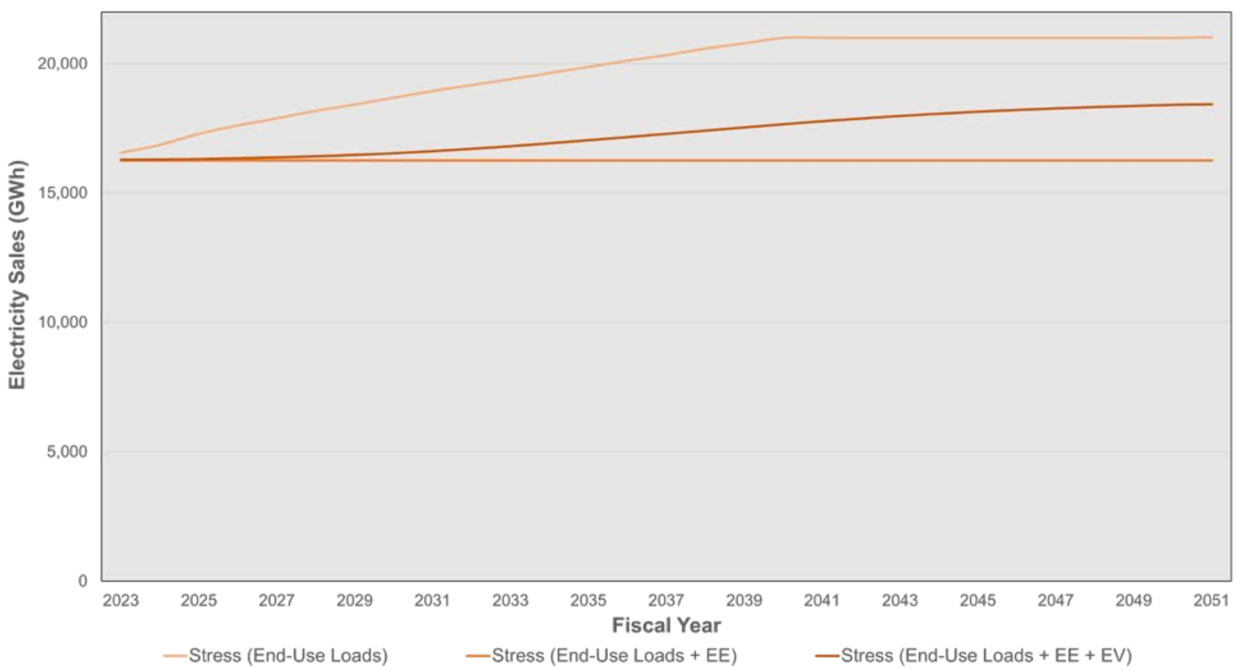


Figure 101. Electric load projections: Stress variation, FY23–FY51

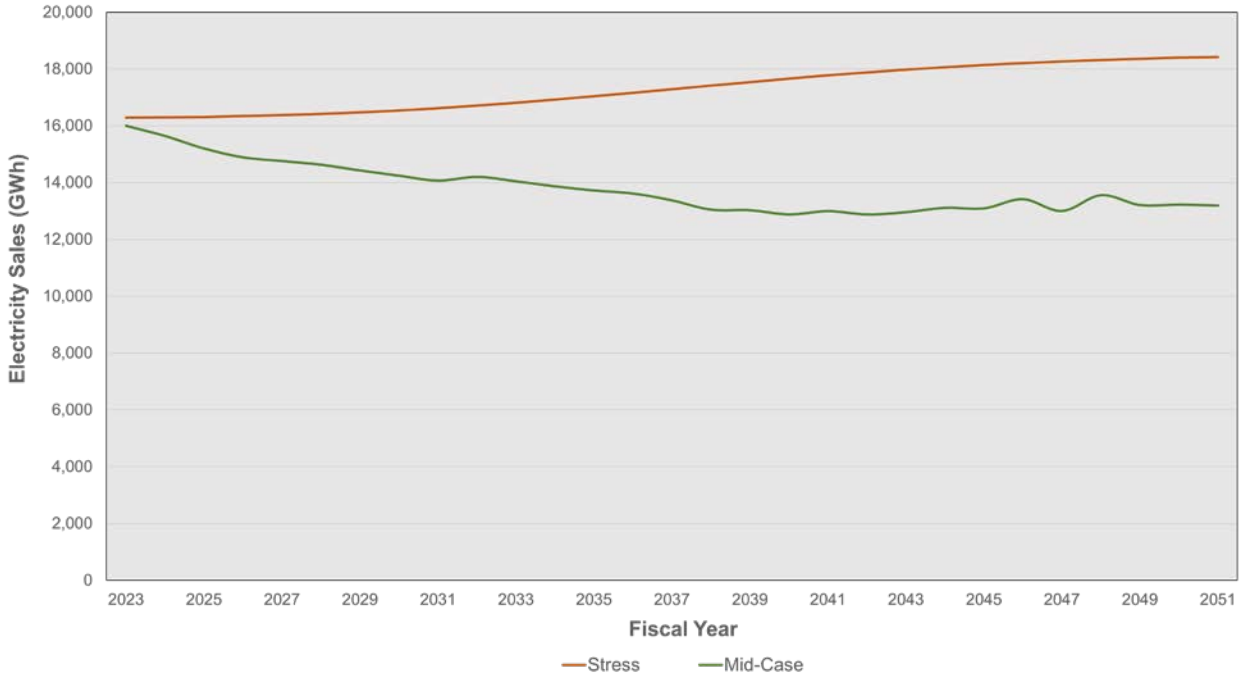


Figure 102. Electric load projections: Mid case and Stress variation, FY23–FY51

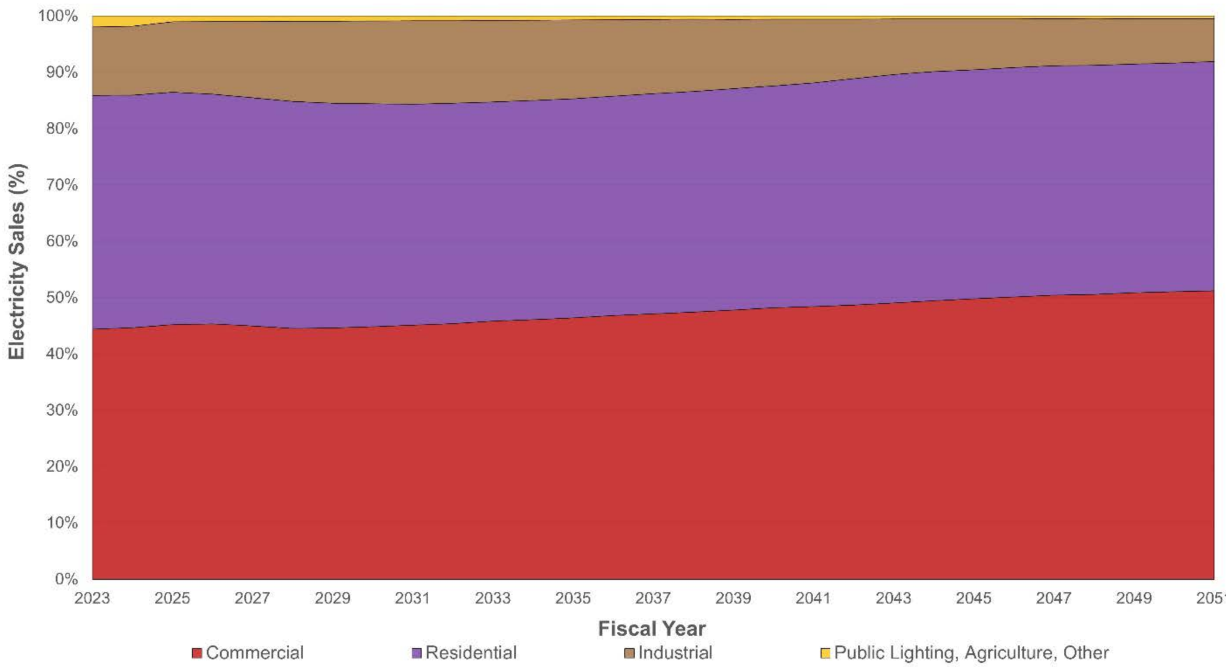


Figure 103. Electric load projections: Mid case variation sector breakdown (percentage), FY23–FY51

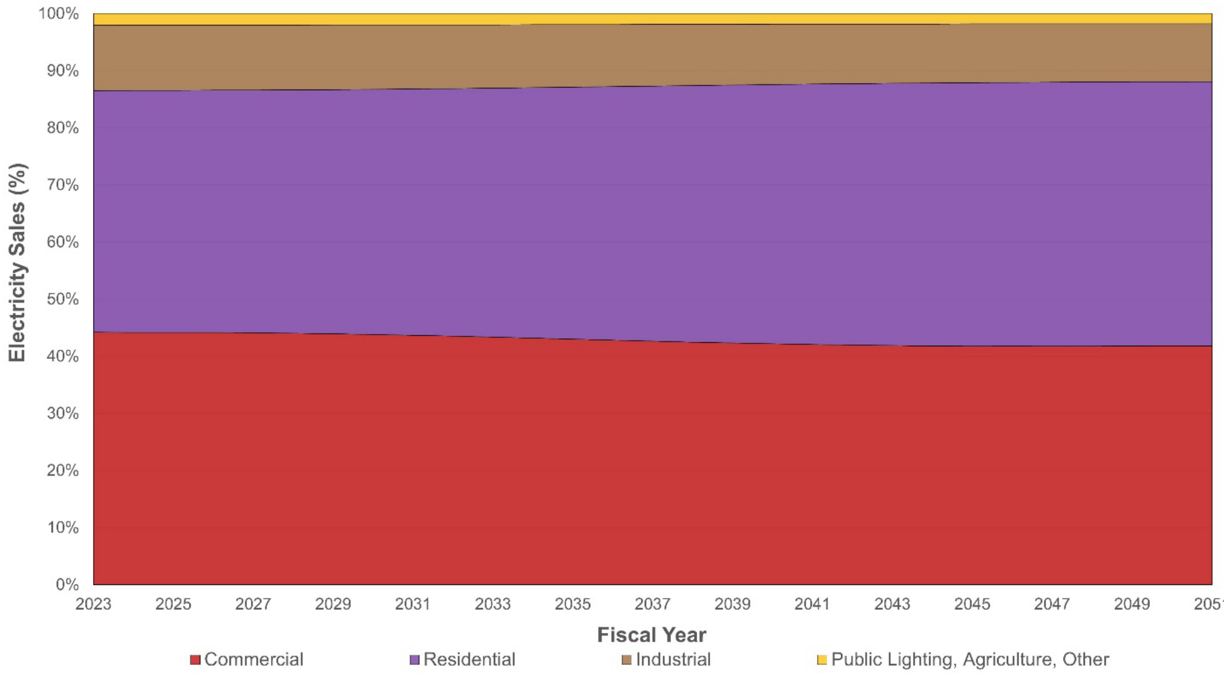


Figure 104. Electric load projections: Stress variation sector breakdown (percentage), FY23–FY51

5.4.3 Electric Load Variations: Interpretation

The main difference in the overall electric load variations is driven by assumptions about end-use loads. The assumptions for energy efficiency savings are the same in both variations, and the assumptions for EV loads (on an annual basis but not on an hourly or sectoral basis) are also similar in both variations (albeit slightly higher for the Stress variation).

In the Mid case variation, end-use loads slightly decrease from FY23 to FY51. This decrease is primarily driven by projections for population and economic factors. In the Stress variation, end-use loads significantly increase from FY23 to FY40 and then remain constant from FY40 to FY51. This is because the Stress variation assumes the combination of end-use loads and energy efficiency (i.e., Act 17 energy efficiency targets for 2040) results in a flat load. Therefore, as we assume Puerto Rico achieves the Act 17 energy efficiency goals, the end use loads by definition increase significantly.

For both variations, energy efficiency is projected to reduce loads and EVs are projected to increase loads. However, the impact of energy efficiency reductions is projected to be larger than the impact of EV increases. For the Mid case variation, the commercial sector is the largest contributor to total loads and its percentage contribution increases over time. For the remaining sectors, the percentage contribution to total loads decreases over time. For the Stress variation, the residential sector starts off as the second largest contributor to total loads, after commercial loads, but its percentage contribution increases over time and by FY51 it is the largest contributor. The percentage contribution of the commercial sector slightly decreases over time, while the percentage contribution of the remaining sectors remains steady.

6 Scenarios

Nate Blair[1]

[1] National Renewable Energy Laboratory

Section Summary

This section provides background and methodology on the scenarios analyzed in this study and variations thereof. It also provides background on how Advisory Group feedback strongly informed the final set of scenario definitions. Many stakeholders in Puerto Rico are deeply concerned about energy system reliability, resilience, affordability, and land use. To this end, the scenarios were intended to provide sufficient information regarding potential long-term impacts to enable near-term decision-making.

The analysis includes three scenarios that meet the goal of 100%-renewable energy by 2045 across three sets of assumptions regarding deployment of distributed solar, each with two land-use variations and two electricity load variations, resulting in 12 combinations. The three main scenarios are:

- **Scenario 1: Economic adoption of distributed energy resources (Economic Adoption):** Distributed energy resource (DER) adoption is based on financial savings and the value of backup power to building owners and is prioritized for critical services like hospitals, fire stations, and grocery stores.
- **Scenario 2: Equitable deployment of distributed energy resources (Equitable Adoption):** Deployment of DERs is expanded beyond Scenario 1 to include remote and very low-income households.
- **Scenario 3: Maximum (prescribed) deployment of distributed energy resources (Maximum Adoption):** DERs are deployed on all suitable rooftops at a level that meets their critical loads.

Key Findings

- Scenario definitions were strongly informed by stakeholder input, which was, in turn, often motivated by a desire for energy justice.
- Scenarios focused first on varying levels of distributed solar photovoltaics (PV) and storage (three scenarios). We also modeled variations for land use for utility-scale solar and wind and electric load trajectories.

6.1 Methodology

6.1.1 Examples of Scenario Analyses

A scenario in PR100 was defined as a possible pathway toward a renewable energy future driven by a set of inputs (see Figure 105). The national laboratories involved in PR100 have conducted a variety of projects based around scenario analysis, a common method for examining trade-offs for current and near-term decisions and the anticipated impact of those decisions over the long term. The scenarios were structured to meet the needs of the decision makers and typically to answer certain questions. Scenarios are intended to enable near-term decisions with information about likely impacts. However, there are too many unexpected and unmodeled changes over time to accurately predict what will happen in the future.

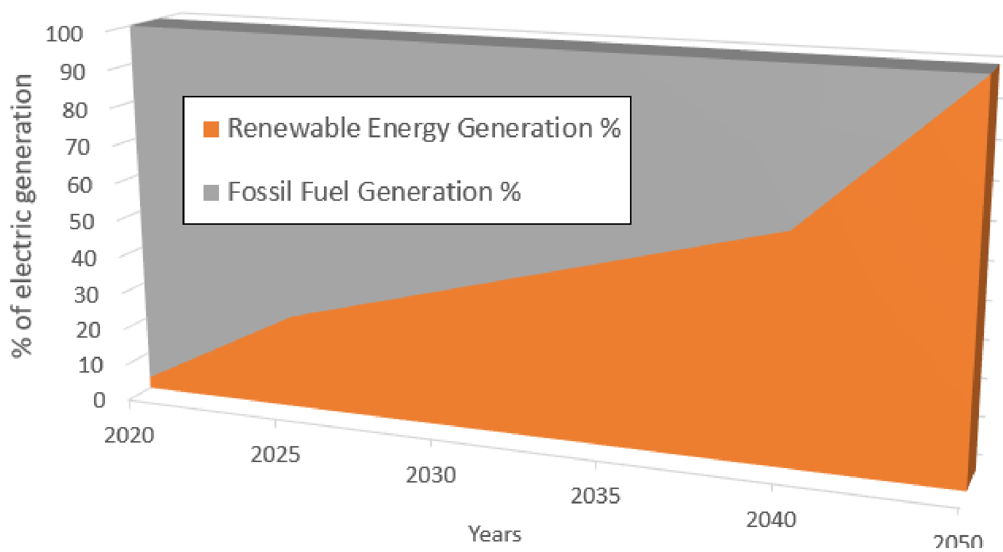


Figure 105. Illustrative depiction of a scenario for PR100

To provide additional background, scenario analysis is often performed where the varied inputs focus on technology cost; this is typical of many U.S. Department of Energy (DOE) scenario analyses as DOE determines the long-term impact of research investments. An example of that in Figure 106 is the annual National Renewable Energy Laboratory (NREL) Standard Scenarios,[108] which looks at the future of the electric grid of the 50 U.S. states while varying costs and other factors. This huge range of 50+ scenarios leads to a variety of energy futures and allows analysis of the impact of future technology costs as well as factors tangential to the electricity sector (such as policy and demand growth).

[108] "Standard Scenarios," NREL, https://www.nrel.gov/analysis/standard-scenarios.html

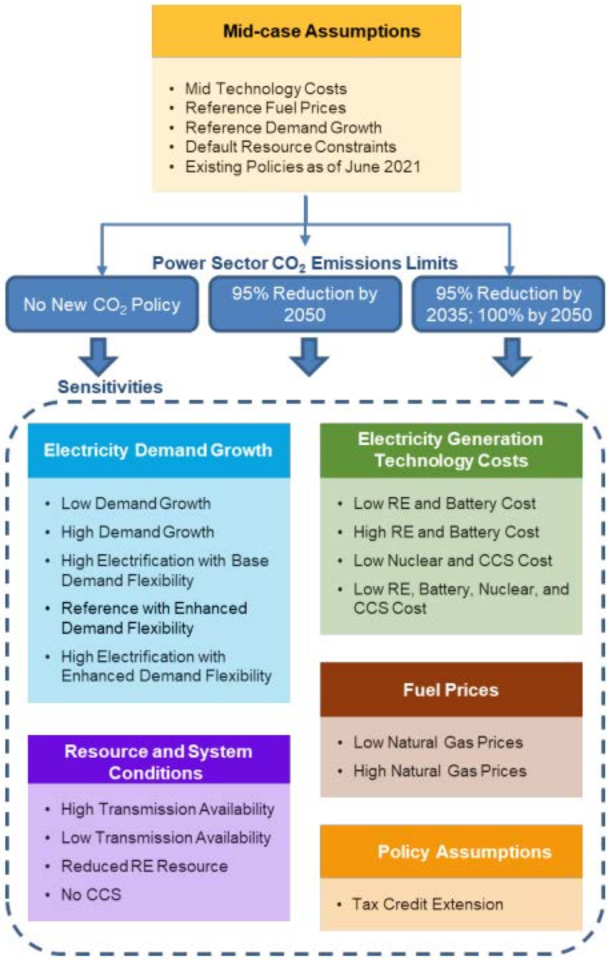


Figure 106. List of scenario variations for NREL's 2022 Standard Scenarios

Gagnon et al. (2023)

Another example of scenario analysis is the recently completed Los Angeles 100 study,[109] which, like PR100, was strongly driven by stakeholders and focused on a local goal of 100% renewable energy for the electricity sector. Although the LA100 study was similar in concept, as shown in Figure 107, the drivers of most importance to the local stakeholders were different from those identified in this study; in addition, LA100 focused on compliance with California Senate Bill 100, transmission constraints, electrification of natural gas loads, and the use of biofuels. A key trait of LA100 that is similar to PR100 was the focus on a goal and related legislation—Act 17 in the case of Puerto Rico. In addition, both LA100 and PR100 have had extensive interaction with a variety of stakeholders. Finally, the forthcoming LA100 Equity Strategies report will focus on energy justice,[110] as we did in PR100.

[109] "LA100: The Los Angeles 100% Renewable Energy Study," NREL, https://www.nrel.gov/analysis/los-angeles-100-percent-renewable-study.html

[110] "LA100: The Los Angeles 100% Renewable Energy Study and Equity Strategies," NREL https://maps.nrel.gov/la100/equity-strategies.

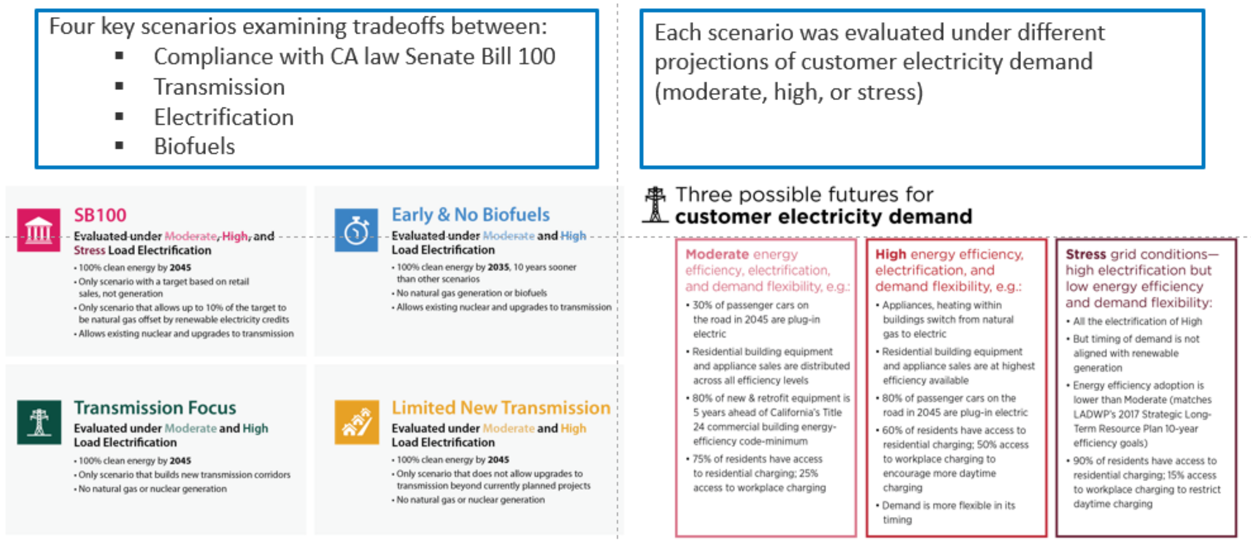


Figure 107. Characteristics of the Los Angeles 100 study

"LA100: The Los Angeles 100% Renewable Energy Study," NREL, https://www.nrel.gov/analysis/los-angeles-100-percent-renewable-study.html.

A final example of scenario analysis that also has similarities to Puerto Rico is the work done by NREL for the island of Oahu in Hawaii. The Engage modeling tool (described in Section 8, page 209),[111] which was used in PR100 for capacity expansion, was developed and continues to be used in Hawaii. Oahu has very high energy consumption and limited land available for renewables development (and a variety of competing uses). For offshore wind, there are technical challenges as in Puerto Rico as well as competing maritime uses and opposition to offshore wind for visual reasons. Shows two scenarios represented in the Engage modeling tool: (1) on the left side, there is no offshore wind and deployment of 2,500 MW of utility-scale solar photovoltaics (PV) and (2) on the right side, there is 1,200 MW of offshore wind and 500 MW of utility-scale PV. These scenarios allow decision makers in Hawaii to examine trade-offs in land and maritime surface uses to meet a 2045 100% renewable energy goal for the electric sector.

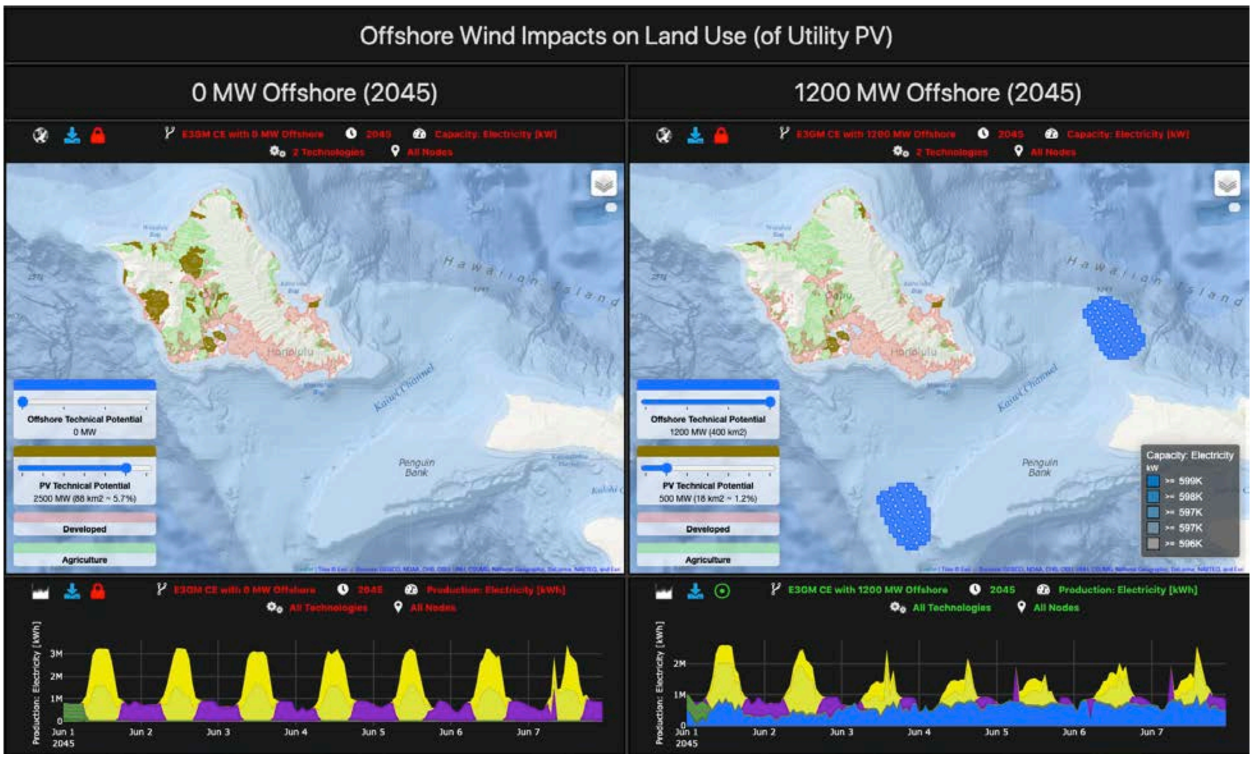


Figure 108. Oahu (Hawaii): Scenarios from Engage modeling examining only land-based PV versus offshore wind and PV

6.1.2 Three Core Scenarios

The scenarios defined for PR100 were developed through extensive interaction with our Advisory Group, represent three possible pathways for Puerto Rico to achieve 100% renewable energy by 2050, and reflect varying priorities regarding how best to achieve the goal and interim targets.

[111] "Engage Energy Modeling Tool," NREL. https://www.nrel.gov/state-local-tribal/engage-energy-modeling-tool.html/.

Key Finding: Scenarios have been strongly informed by stakeholder input which is, in turn, driven often by the need for energy justice.

Engaging in a deliberate process of discussing energy justice frameworks with each topic lead in the study and how to call out or integrate energy justice more explicitly ensured these three scenarios were supplemented by variations on land use and load. Identified stakeholder priorities included affordability, reliability, resilience, and equitable access. Based on stakeholder input, the PR100 project team developed a bookend approach to scenarios driven primarily by the extent of adoption of distributed energy resources (DERs)—rooftop solar and storage—with Scenario 1 simulating the lowest level of DER adoption and Scenario 3 simulating the highest level. The bookend scenarios individually are perhaps unlikely to occur but the probability that the future will be between the bookends is higher.

In Scenario 1, we used NREL's dGen model (described in Section 7) to calculate the likely adoption of distributed solar and storage based on economic adoption, that is, positive financial savings to the homeowner or business owner through installation and use of the DERs. Effectively, we were looking at a payback period for acquiring the system—the shorter the payback period, the faster adoption in Puerto Rico happens. Note that this is "economic" from the perspective of the building owner and their cost versus rates to the utility. It does not imply anything regarding macro-economic impacts (see Section 10.2 for more information).

Moving through these scenarios, the level of DER adoption increases. Scenario 2 builds on Scenario 1 by requiring remote and very low-income households to adopt rooftop solar and storage systems. Details for Scenario 2 are provided in Section 6.1.3. Finally, Scenario 3 deploys enough rooftop solar and storage to meet the critical loads for all buildings, resulting in extensive deployment across Puerto Rico. Table 22 summarizes the three scenarios, including short names used in results presented in Section 6.2. Details on how this is implemented in the NREL dGen model are covered in Section 9.

Table 22. PR100 Final Scenario Definitions Based on Extensive Stakeholder Input

Scenario Number	Scenario Name	Description	Short Name
1	Economic Adoption of Distributed Energy Resources	DER adoption is based on financial savings to homeowners and business owners; installation is also prioritized for critical services like hospitals, fire stations, and grocery stores.	Economic Adoption
2	Equitable Adoption of Distributed Energy Resources	Deployment of DERs is prioritized beyond Scenario 1 for remote and very low-income households.	Equitable Adoption
3	Maximum Adoption of Distributed Energy Resources	DERs are deployed on all suitable rooftops at a level that meets their critical loads.	Maximum Adoption

In results from Year 1 of the study, there was a fourth scenario. It required critical services facilities (e.g., hospitals, nursing homes, fire stations, pharmacies, grocery stores, water, and wastewater treatment facilities) to adopt rooftop solar and storage systems in addition to the economic deployment in Scenario 1. Preliminary adoption levels of distributed PV and storage for

Scenario 1 with both Mid case and Stress load indicated more than 2.8 GW of PV and associated storage. The adoption of rooftop PV shifted with these final results but the underlying drivers of adoption—including high value of backup power, high utility rates, and anticipated declines in PV and battery costs—will continue to drive significant deployments. As a result of these high deployment levels, a significant fraction (80%) of commercial buildings was shown to adopt rooftop systems. The additional Year 1 scenario was defined by assuming the economic deployments of Scenario 1 with the addition of critical facilities, which represent approximately 10% of the total commercial buildings. Because of their assumed higher-than-average value of backup power, it can be safely assumed these facilities were included in the economic adoption levels of Scenario 1. The similarity is enhanced by assuming net metering continues into the future.

Therefore, the additional critical facilities scenario completed initially resulted in the same level of adoption and was combined with the economic scenario into a single scenario to analyze (economic and critical services).

Figure 109 further illustrates the distinctions among the three scenarios, from more utility-scale renewables by 2050 in Scenario 1 to most rooftops having solar and storage with minimal utility-scale renewables by 2050 in Scenario 3.

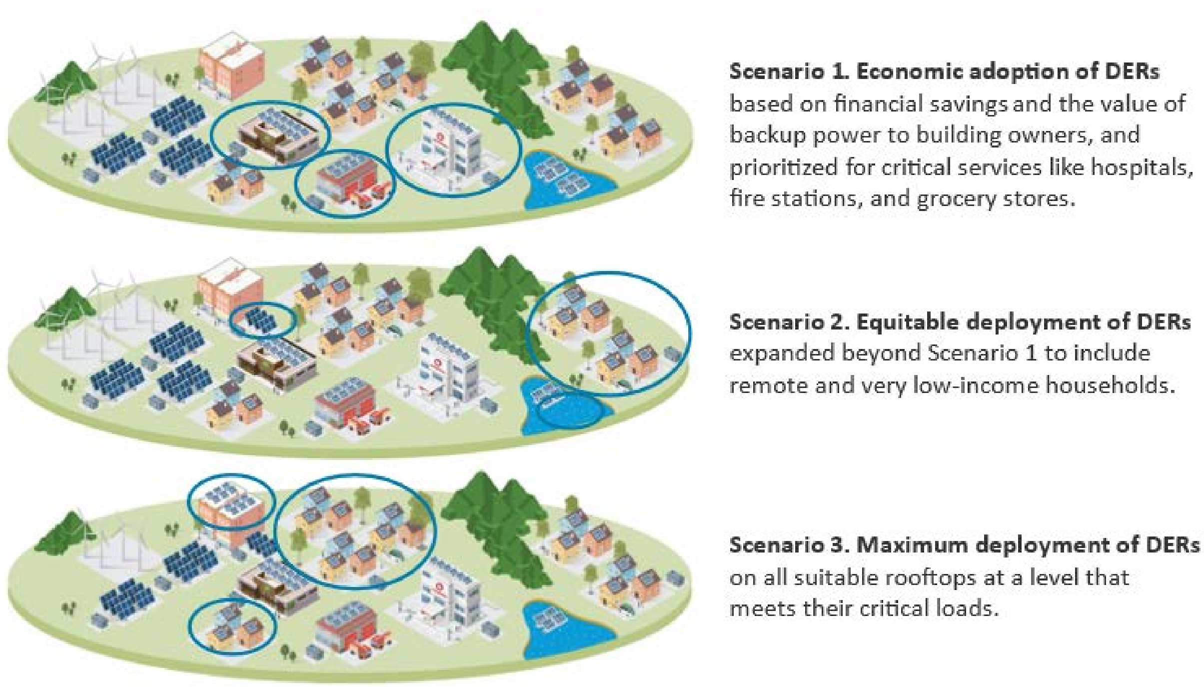


Figure 109. Three scenarios modeled in PR100, distinguished by varying levels of DER adoption

Differences between scenarios are circled in blue.

These three scenarios were subject to a variety of assumptions about system costs and future electricity rate structures as well as the value of backup power to the customer, which is high in Puerto Rico. These assumptions, informed by engagement with the Advisory Group, are discussed in Section 6.2.

6.1.3 Scenario 2 Detail

Scenario 2 expands the number of rooftop PV and storage systems deployed to very low-income households, defined as households earning 0%–30% of area median income, and households in remote areas that would not have bought systems based solely on economics. The description of the agents that represent different customer groups is described in Section 7. In Scenario 2, the model assumed rooftop solar and storage adoption by 2050 by the following:

1. Residential rooftops in remote areas
2. Very low-income households *across all* of Puerto Rico.

Remote areas can be defined by outage duration after a major disruption such as Hurricane Maria, typical outage durations in the absence of a storm or other disruptive event, and outage metrics such as the system average interruption duration index (SAIFI) and the system average interruption duration index (SAIDI). Based on input from project partners at the University of Puerto Rico at Mayagüez (UPRM) and other stakeholders, we identified 18 municipalities across Puerto Rico represented in Figure 110 where power restoration after outages is difficult—Adjuntas, Aguas Buenas, Arroyo, Ciales, Comerío, Corozal, Culebra, Jayuya, Luquillo, Maricao, Maunabo, Morovis, Naguabo, Orocovis, Patillas, Utuado, Vieques, and Yabuco. We defined these municipalities as "remote" for inclusion in Scenario 2. These areas combined represent less than 9% of residential utility customers. Note that modeling at the municipality level could include a mix of customers that are difficult to reconnect and those more easily reconnected after an outage but, on the whole, most customers were remote.

Figure 110. Scenario 2: Map of modeled remote municipalities

6.1.4 Scenario Updates in Year 2

In Year 2 we made some updates to the scenarios based on stakeholder feedback. A summary of updates is presented in Table 23. All these changes impacted the results somewhat, with the largest impact coming from the first item in the table, which entailed focusing system size for distributed PV and storage on the critical loads for a residence. That analysis is discussed in detail in Section 7.

Table 23. Year 2 Scenario Updates

Driver	Scenarios Impacted	Change Description
Lack of affordable scenarios	All	Analyzed systems sized for critical loads rather than entire loads
Ability to examine details of low- and moderate-income households	All	Created more detail in distributed generation model (more “agents”) to represent various income levels
Utility-scale in the 50 U.S. states PV sizing is perhaps too large for Puerto Rico	All	Reduced utility-scale PV system size lower limit to 5 MW in land availability analysis in Year 2
Interest in including microgrids in PR100	All	Compared results to prior microgrid analysis for Puerto Rico

6.1.5 Land Use Variations

We received feedback from stakeholders across Puerto Rico regarding concerns about land use for utility-scale renewable energy deployment. As discussed in Section 4, we generated two scenario variations for land use. In both options, extensive areas of Puerto Rico were excluded from utility-scale deployment (both on land and for offshore wind). The Less Land variation excludes land defined by the Puerto Rico Planning Board (PRPB) as agricultural land comprising the following: Specially Protected Rustic Land – Agricultural (SREP-A), – Agricultural/Ecological (SREP-AE), – Agricultural/Hydric (SREP-AH), and – Agricultural/Landscape (SREP-AP). Therefore, only land areas classified as Rustic Common (SRC), Urbanizable Land – Not Programmed (SURNP), and Urbanizable Land – Programmed (SURP) were included in the Less Land variation. The More Land variation includes land defined as agricultural land or with SREP-A, SREP-AE, SREP-AH, and SREP-AP classification. Both the More and Less Land variations exclude Agricultural Reserve areas, which encompass multiple PRPB land use categories. Many of the Agricultural Reserve areas have been legislated on an individual basis and have their own particular laws. See Section 6, Table 4, “More and Less Land Variation Exclusions and Inclusions” for details.

Table 24 shows the impact of the land use variations on the total technical potential for mature renewable technologies. As can be seen, the Less Land restrictions have the greatest impact on wind technical potential reducing it to under 2 GW.

Table 24. Technical Potential Variations for Less Land and More Land Scenario Sensitivities

Land Access	Utility-Scale PV Capacity (GW)	Utility-Scale PV Area (km^2)	Utility-Scale Wind Capacity (GW)	Utility-Scale Wind Area (km^2)
Less Land	14.22	203	1.61	537
More Land	44.66	638	4.60	1,533

6.1.6 Electric Load Variations

The project team developed two electric loads variations to apply to the scenarios. As described in Section 5, the end-use electric load projections that were developed for the Mid case trajectory decline over time. This is consistent with the end-use load methodology that was used in the PREPA's 2019 IRP (PREB 2020) and builds on inputs about population, economic trends, energy efficiency measures, and electric vehicle adoption assumptions. The result is that our Mid case electric load variation trends downward. Feedback from the Advisory Group indicated that if reliable power and resilience can be demonstrated across the Commonwealth in coming years (as we modeled in these scenarios), economic growth and population will not decline as anticipated. Section 14.3 also indicates that the level of electric development will be an economic boon in Puerto Rico. Therefore, we created a second electric load forecast that increases over the years, termed the Stress load variation. This forecast provides a potentially upper bound or bracket on electric load. In addition, an increasing load will result in higher levels of generation deployment, which should set the high end of anticipated deployment, which is of interest to stakeholders. Other electric systems, such as in the contiguous United States, anticipate load growth into the future of a few percent per year—that is, every year some new capacity and energy generation must be added to keep up with this growing load. Conversely, in Puerto Rico, due to the anticipated declining load, all new additions of renewables will reduce existing energy generation, leading to premature retirements potentially, which makes this a unique system. The resulting two load variations are shown in Figure 111, with the components outlined in Table 25.

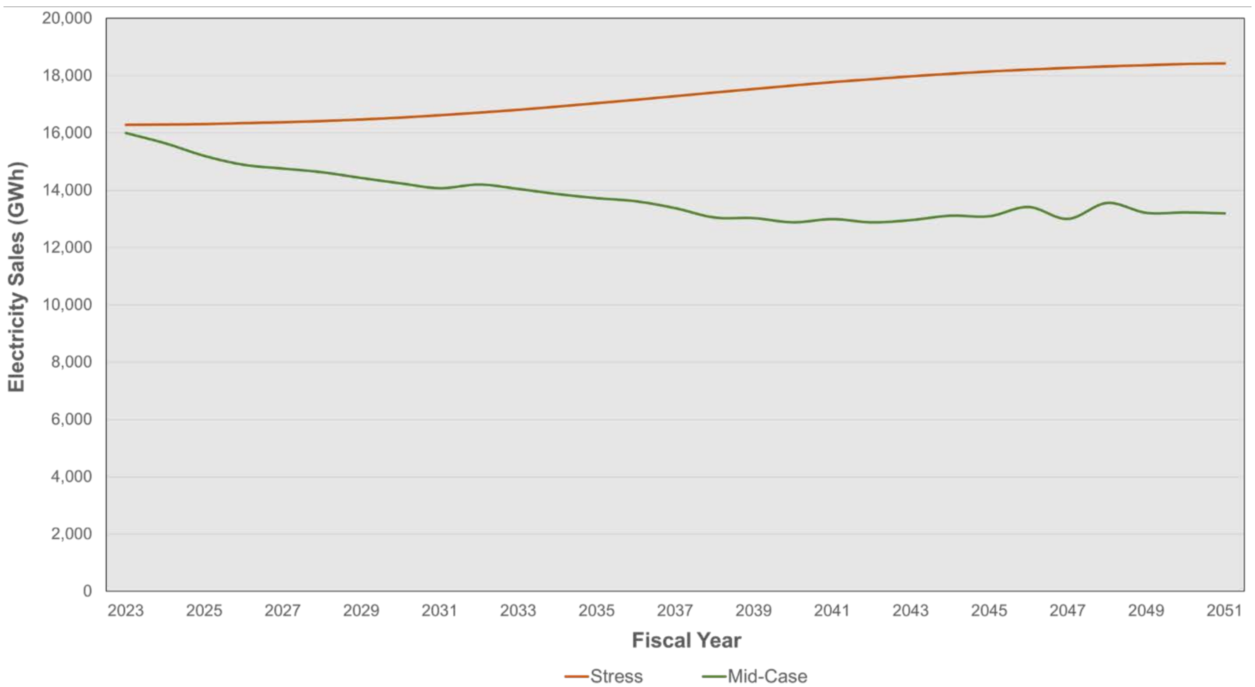


Figure 111. PR100 electric load projections: Mid case and Stress variations for all of Puerto Rico (FY23–FY51)

Table 25. Description of Mid case and Stress Electric Load Variations

Load	Mid case	Stress
End-use loads	Medium	Stress
Energy efficiency	Act 17 Goals	Act 17 Goals
Electric vehicles	Sufficient Workplace Charging	Insufficient Workplace Charging

The Stress projection would result in the highest loads and the largest electric system build-out.

6.1.7 Scenario and Variation Combinations

Combining Scenarios 1 through 3 with the two load variations and the two land use variations results in a set of 12 total scenario combinations. These combinations are referred to in this report using the naming convention enumerated in Table 26. Not all scenarios and variations are relevant to all portions of the analysis.

Scenarios focused first on varying levels of distributed PV and storage (three scenarios). Two variations on use of agricultural land for utility-scale solar and wind are added. A variation of two options for load trajectories are also modeled.

Key Finding: Scenarios focused first on varying levels of distributed PV and storage (three scenarios). Two variations on use of agricultural land for utility-scale solar and wind are added. A variation of two options for load trajectories is also modeled.

Table 26. Full Table of Scenarios and Variations Used in PR100

Scenario Number	Scenario Short Name	Variation 1: Land Use	Variation 2: Electric Load	Scenario Identifier
1	Economic Adoption	Less Land	Mid	1LM
1	Economic Adoption	Less Land	Stress	1LS
1	Economic Adoption	More Land	Mid	1MM
1	Economic Adoption	More Land	Stress	1MS
2	Equitable Adoption	Less Land	Mid	2LM
2	Equitable Adoption	Less Land	Stress	2LS
2	Equitable Adoption	More Land	Mid	2MM
2	Equitable Adoption	More Land	Stress	2MS
3	Maximum Adoption	Less Land	Mid	3LM
3	Maximum Adoption	Less Land	Stress	3LS
3	Maximum Adoption	More Land	Mid	3MM
3	Maximum Adoption	More Land	Stress	3MS

6.2 Inputs and Assumptions

Several key points about both obvious and implied assumptions are consistent across the forward-looking scenarios described above.

First, we did not examine any futures in which there is no central grid. There was discussion about this option in which every building or group of buildings (in a mini grid) is independently owned and there is no central grid. However, the PR100 project team did not intend to model this because of stakeholder feedback and because, while many buildings can meet all their own load with PV on their own roof or close-by (small mini grid, carport, roadway), there will inevitably be some large multifamily buildings, extremely shaded buildings or buildings with large loads (such as industrial users) for which longer distances would need to be covered to provide adequate power. These longer distances could reduce the resilience compared to rooftop PV at the site. Additionally, providing enough PV and storage for a buildings load for all hours of the year (off-grid) would require significantly more battery storage than needed for critical loads during an outage. Batteries would degrade more quickly if cycled every day as well causing replacements to be needed sooner.

Another notable assumption is that we enforced Act 17 in all these scenarios. This means that, although two energy efficiency trajectories are described above, we modeled only the energy efficiency scenario that achieves the 30% energy efficiency reduction goal by 2040 as described in Act 17. Adherence to the law also meant that our modeling enforced getting to 40% of the energy needs provided by renewable energy by 2025 (and 80% by 2040 and 100% by 2050). Particularly for the 2025 goal, this was aggressive, with Puerto Rico needing to deploy more than 2 GW of solar or wind by December 2025. Significant deployment acceleration would need to occur to achieve this as our scenario results indicate. In reality, deployment of even the identified Tranche 1 plants has been delayed because of renegotiations and legal challenges to the use of the land identified for development.

Relatedly, our scenarios assumed the existing fossil plants would retire on the announced trajectory defined in Act 17. These retirements could make the current resource adequacy shortage even worse, especially if the renewable plant deployments continue to be delayed.

Finally, although this study includes resilience analysis of grid recovery from simulations of hurricane-related damage (Section 12.9), our scenarios did not assume impact to the grid from a major storm during the transition to renewables. If the grid were properly storm-hardened and improved, it might be appropriate that storm impacts might be less than indicated by experience—but it should be highlighted.

6.3 Interpretation and Energy Justice

These scenarios covered a broad range of uncertainties about the future and portrayed various options Puerto Rico stakeholders will need to consider in order to make near-term decisions. The purpose of the scenario approach was not to provide a single, most likely future scenario for the energy sector but rather to provide a basis to compare trade-offs and uncertainties around electric load, rooftop PV and storage deployment, land use, and other effects to present a range of outputs that could have safety, economic, or other impacts.

Although there was uncertainty in our inputs and modeling results that makes it unlikely that any single scenario will match the future reality, the brackets we created with these variations provide a range of outputs that support decision-making on pathways that lie within these scenarios.

Our scenarios imply a mix of adopted rooftop solar and storage systems that save significantly for the homeowner or business owner. In addition, in Scenarios 2 and 3, we forced in the adoption of significantly higher amounts of rooftop PV to examine the impacts of these levels of adoption. In this analysis, we did not assume how those systems would be paid for or whether any public or federal funds would be allocated to pay for them. By definition, Scenarios 2 and 3 exceed what is likely to be adopted based on bill savings and resilience savings.

Key Finding: Scenarios were strongly informed by stakeholder input which is, in turn, motivated often by the need for energy justice.

There are several key energy justice impacts in the creation of the PR100 scenarios. By justice type, they are as follows:

- **Procedural:** Stakeholders were extensively engaged in structuring and defining the scenarios to be studied. For the first 6 months of this study, we gathered information about critical questions from stakeholders. As described at the beginning of this section, there are many different approaches to creating scenario analyses.
- **Recognition:** Meaningful local perspectives are captured in the scenarios. Focusing primarily on distributed PV and storage has not been done before; the additional key areas of land use and load variations are also different from prior scenario work.
- **Distributive:** By tracking different key groups within the scenarios (particularly the equitable scenario), we provided information about the impact of the scenarios on individual sectors of the population in Puerto Rico—rather than simply combine low-income and wealthy citizens into one sector.
- **Restorative:** The goal in all scenarios was to provide resilience to all (through rooftop PV and storage or through a resilient grid), but Scenario 2 in particular focused on those citizens most impacted by prior events.

7 Distributed Photovoltaics and Storage Investments Over Time

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Section Summary

This section reviews our modeling and analysis of Puerto Rico's future growth in distributed photovoltaics and storage investments over time. We discuss the simulation methods, assumptions, inputs, and the resulting growth predictions through 2050. Future deployment of utility-scale resources is addressed in Section 8 (page 209).

Key Findings

- Under all scenarios (Scenarios 1, 2, and 3) and variations, modeling results show that the amount of rooftop solar photovoltaic (PV) capacity and storage capacity deployed in Puerto Rico by 2050 will be significant both in aggregate capacity and in instantaneous power exported back to the distribution grid during the day. See Figure 122 (page 202) for a comparison of the annual load projections and rooftop PV production.
- Model results indicate that rooftop PV and storage deployment will continue even as the grid becomes more resilient because of bill savings and the ongoing desire for local resilience at the building level for extreme weather. As battery and PV costs continue to decrease, ongoing rooftop PV and battery adoption might result in more system capacity than would be necessary toward 2050 if significant utility-scale renewables are built in the near term.

Considerations

- Because of the building-level resilience that rooftop PV and storage provide, accelerating the deployment of rooftop PV and storage will therefore accelerate increased resilience. This greater building-level resilience might reduce both the urgency to restore the grid after an outage and the resilience needs for the grid system.
- For Scenario 2 specifically in remote areas, coordination of these rooftop systems into microgrids could be examined for system cost and/or utility financial savings with similar resilience benefits.
- Prioritizing the deployment of more virtual power plants would support greater interaction with the grid needs (at both the distribution and transmission levels). This would follow from the fact that aggregators and virtual power plants could allow a grid operator to dispatch battery storage to support the overall system and that revenue could support additional rooftop PV and storage deployment (to reach higher levels as in Scenarios 2 and 3). These technologies could be effective today if a notable portion of the installed base of PV and storage participated in a pilot program.
- Ongoing analysis of critical loads over the coming years is vital to correctly sizing PV and battery systems to meet critical loads rather than a home's entire load. This is because critical loads (such as refrigeration, medical equipment, communications equipment, and cooking) during an outage will evolve (1) as grid electricity becomes more reliable leading to more investment in electric appliances and products and (2) as energy efficiency increases broadly and (3) if it is determined that EV charging to some level is a critical load.

7.1 Methodology

7.1.1 Methodology Additions to Handle Current Scenarios

The Distributed Generation Market Demand (dGen) model is a geospatially rich, bottom-up, market penetration model that simulates the potential adoption of distributed energy resources (DERs) for residential, commercial, and industrial entities in the contiguous United States (and beyond in this analysis and other international analyses) through 2050. The National Renewable Energy Laboratory (NREL) developed this agent-based modeling framework to analyze the key factors that will affect future market demand for distributed solar, wind, storage, and other DER technologies in the United States within a single modeling platform. Figure 139 indicates the general process of incorporating the total technical potential, then applying the bill savings and other economics to get to the economic potential, and then looking at what the market needs to get to the market potential and eventually projected adoption. Currently, dGen simulates the adoption of distributed solar, distributed wind, geothermal heat pumps, and distributed PV plus storage (as used in Puerto Rico). In addition, the model is configured to link with utility-scale capacity expansion models such as the Engage modeling tool and the Regional Energy Deployment System (ReEDS) model from NREL. The Engage modeling tool was used for PR100 and is discussed in Section 8 (page 209). All technologies modeled within the dGen framework leverage a database of highly resolved geospatial information along with algorithms for modeling DER economics, customer decision-making, and diffusion of technology over time.

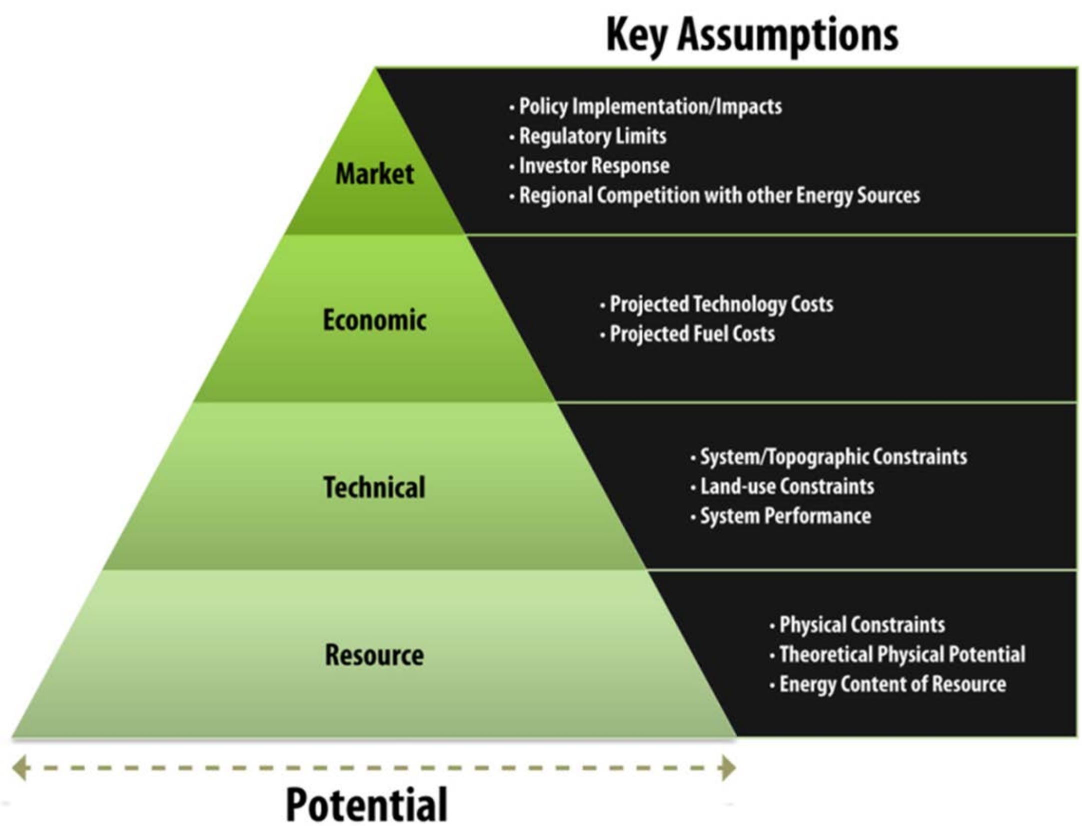


Figure 112. Theoretical steps of analysis within the dGen framework

Source: Lopez et al. (2012)

Behind-the-meter DER demand is simulated by dGen at 2-yr increments from 2014 through 2050 for residential, commercial, and industrial customers. Under the current dGen platform, users can simulate the diffusion of distributed solar or distributed wind individually. Although dGen is fundamentally geospatial, capturing regional variation in the underlying factors that affect market demand across the United States, it captures spatial relationships at a significantly higher level of detail using an updated and expanded geospatial database. The increased spatial resolution of dGen permits more robust deployment forecasts in addition to more sophisticated analyses of those forecasts. Examples of such analyses include correlating DER adoption forecasts with sociodemographic data and EV purchases and overlaying deployment forecasts with distribution networks to improve understanding of local impacts of high levels of DER adoption.

Nearly all data in the model are mapped spatially; site-specific parameters are then linked with locally and regionally variable data sets of other market factors through the data backbone, such as electricity rates and rate structures, policy incentives, and electricity demand. These data sets are combined within a geographic information system to model market penetration at the county and parish levels, and results are aggregated to the state and national levels.

In two U.S. Department of Energy programs—SEEDS (Solar Energy Evolution and Diffusion Studies) and SEEDS-2[112]—dGen was used to help identify barriers to solar adoption in low- and moderate-income (LMI) communities as well as policy opportunities to overcome those barriers. In a first-of-its-kind study (Sigrin and Mooney 2018), dGen modeling found that 25 million LMI buildings across the 50 U.S. states are suitable for rooftop solar. Furthermore, that study revealed that many of these deployments require installation on renter-occupied, mobile home, and nonprofit buildings, which infrequently incorporate rooftop solar. Further, dGen modeling exposed substantial distributional disparities within LMI communities, suggesting that targeted policy would have an outsized impact in expanding rooftop solar deployments and cutting electricity costs for an overburdened population.[113]

[112] "Solar Energy Evolution and Diffusion Studies (SEEDS)," DOE, https://www.energy.gov/eere/solar/solar-energy-evolution-and-diffusion-studies-seeds.
[113] "Two Studies Offer New Insights into Low-to-Moderate Income Solar Adoption," NREL, 2020, https://www.youtube.com/watch?v=WFSD_DNXE_Q.

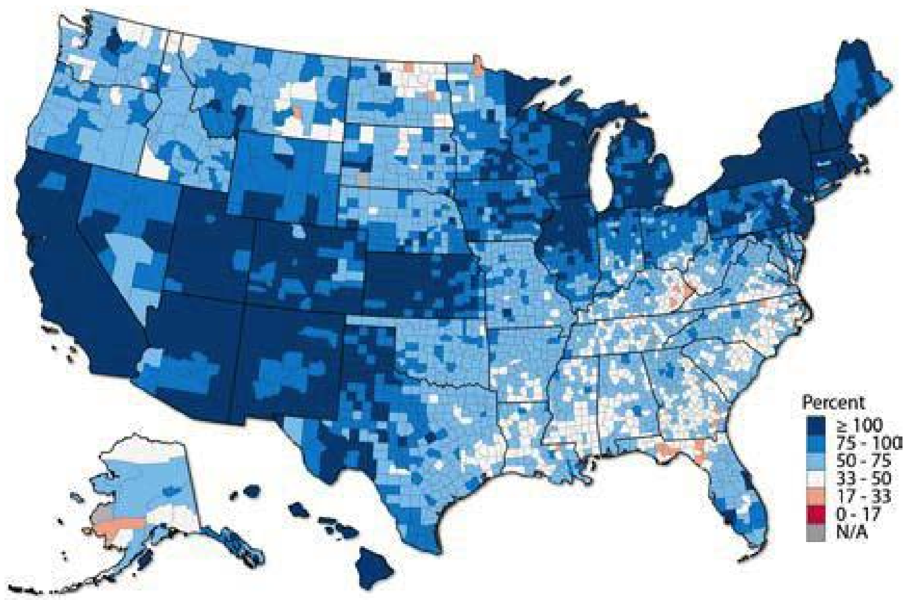


Figure 113. dGen modeling revealed that the percentage of LMI electrical consumption that can be offset by rooftop solar generation is greatest in the Southwest, upper Midwest, and Northeast as well as in Hawaii.

Sigrin and Mooney (2018)

In the same study of LMI customers across the 50 U.S. states (Sigrin and Mooney 2018), dGen was used to generate the Puerto Rico–specific rooftop availability and associated income levels with rooftop availability in Puerto Rico. Details can be found on the dGen website.[114]

7.1.2 An Agent-Based Approach to Distributed Energy Resource Forecasts

The overarching goal of any model is to capture real-world dynamics. In the case of dGen and growth in DERs, these dynamics depend on real people making decisions based on their circumstances, including their funds, friends, awareness levels, and interests. In some cases, such decisions are dominated by consumer behavior, and dGen works to capture that through inclusion of consumer behavior surveys and historical adoption data.

This individual-level detail is approximated in dGen models by agents. An agent is the fundamental unit of dGen models; it could represent an individual, a household, a county, or a statistical aggregate of multiple agent types. Agents in dGen are defined by their spatial location—including, for example, the location's amount of sunshine, its electricity rates, and its demographics—and behave probabilistically according to these numerous data attributes.

For DER predictions, agent-based models offer several distinct advantages:

- They reflect true heterogeneity of populations.
- They scale to any size of analysis.
- They minimize bias in model assumptions by using probabilistic representations.
- They easily incorporate new predictive attributes.

[114] https://www.nrel.gov/analysis/dgen/

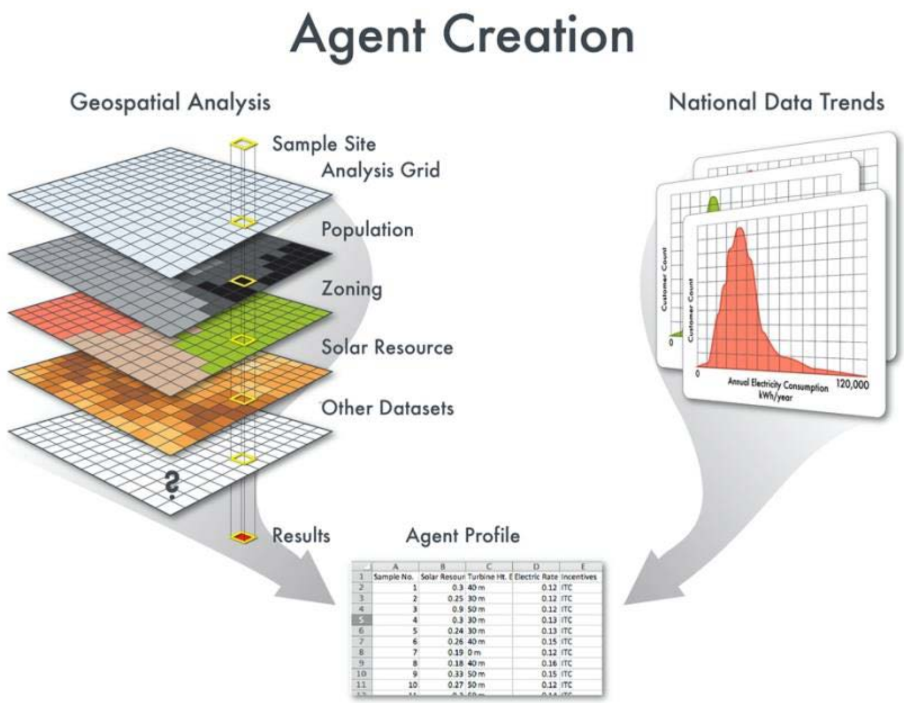


Figure 114. The fundamental design of dGen—multiple spatial layers from peer-reviewed data sets and complementary software—is used to build agents, which are statistical representations of the underlying data.

7.1.2.1 Agent Personality

No model perfectly captures human psychology, but dGen developers have incorporated approximate human thinking into the model, leveraging modern progress in customer psychology (Figure 115).

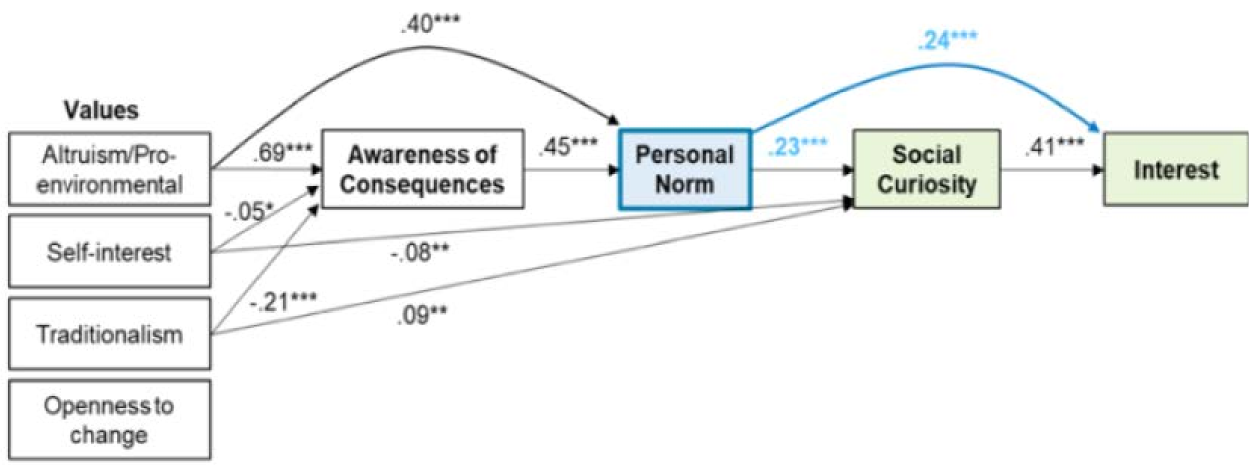


Figure 115. dGen developers have incorporated findings from recent studies on the psychology of energy technology adoption, such as this depiction of how values correlate to solar adoption parameters.

Image from Wolske, Stern, and Dietz (2017)

Surveying area residents is an effective approach to understanding geospatial variation in personalities and preferences, and dGen uses survey results to evaluate the relative importance of different motivators, such as self-interest, curiosity, and altruism. Likewise, agent behaviors in dGen are shaped by adoption trends that accompany any new technologies. dGen applies the Bass model of technology diffusion—a well-documented phenomenon in which adoption over time follows an S-curve—to ensure realistic behavioral dynamics are represented.

7.1.3 Adding Battery Storage to dGen

To model the PR100 scenarios, dGen was used to simulate the cost-effectiveness and subsequent customer adoption of PV and battery storage for residential, commercial, and industrial entities in Puerto Rico. As part of the Storage Futures Study (Prasanna et al. 2021), dGen was modified to enable it to evaluate behind-the-meter battery storage in addition to the existing capabilities for distributed PV. New model development for the Storage Futures Study included the integration of the PySAM battery storage model[115] and the addition of the value of backup power. PySAM is a Python-based application programming interface to programmatically access the functions and models from NREL's System Advisor Model.[116] It is a detailed techno-economic system model that provides the ability to simulate PV, batteries, and other technologies considering detailed system performance and efficiency while linking these to a cash flow analysis. The specific methods and models used to determine the technical, economic, and market potential in dGen are presented in Figure 116.

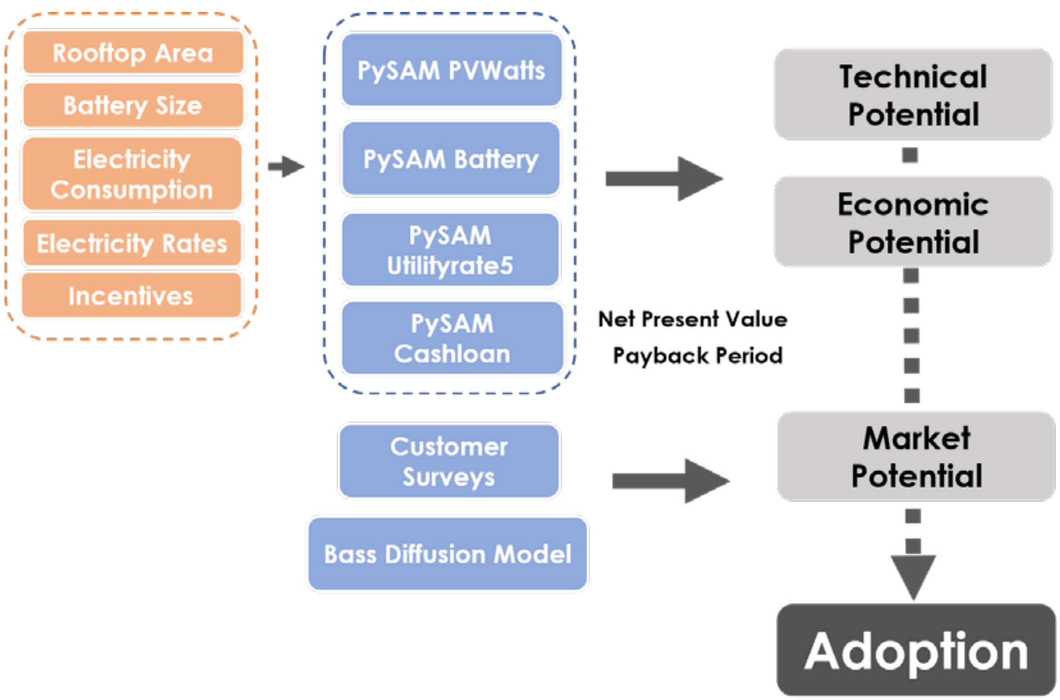


Figure 116. Models and tools to determine adoption/deployment of PV and battery storage systems

[115] PySAM Version 4.2.0., NREL, accessed July 26, 2022. https://github.com/nrel/pysam.
[116] "System Advisor Model," NREL, https://sam.nrel.gov.

7.1.4 Interaction Between dGen and Distribution System Analysis

It is important to describe the methodology of the tool chain relevant to distributed generation. dGen does not limit the deployment of distributed generation based on current limitations of the distribution grid. In fact, although dGen contains much geospatial data, it models neither individual feeder lines nor the distribution grid generally. This modeling implicitly assumes adjustments to the distribution grid can be made to host the economic levels of distributed generation deployed. In Puerto Rico and in PR100, the level of adoption is far higher than typically modeled in the contiguous United States. As a result, assumptions about incremental improvements in hosting capacity of distributed generation are inappropriate.

Therefore, we conducted analysis of the distribution grid changes needed to absorb the potential load variations (Mid case and Stress) as well as the distributed generation flowing back onto the grid (Section 11, page 347). When using an annual lens to consider the energy impacts, distributed generation and energy efficiency (and falling loads) decrease the impact on the energy that the grid needs to provide. However, when considering hourly and subhourly power flows, multiple gigawatts of rooftop PV output flow out of the rooftop systems and onto the grid. With a daytime load in Puerto Rico of roughly 3 GW, the distributed generation can overwhelm that demand and create backflow through the transformer and onto the transmission grid. Therefore, the outputs of the rooftop PV and storage modeling were an input to the distribution grid analysis, which analyzed this issue (Section 12, page 401).

7.1.4.1 Model Development for PR100

Prior to PR100, Sigrin and Mooney (2018) constructed a dGen model infrastructure for Puerto Rico and conducted basic analysis, but that did not preclude the need for significant model development throughout the current study. The PR100 effort was unique: We defined Scenario 2 and Scenario 3 with a greater proportion of distributed PV than is typical for modeling of the contiguous United States, which required some additional model development. In addition, we needed to adjust historical data and other inputs for Puerto Rico.

7.2 Energy Justice Implications

The rooftop PV and storage focus in PR100 scenarios and the level of detail we incorporated into rooftop PV and storage adoption modeling indicate the energy justice perspective—specifically recognition justice—as PR100 was molded by input from stakeholders in Puerto Rico. Though rooftop PV and storage were always planned as components of PR100, we defined the scenarios evaluated in PR100 by level of DER adoption based on stakeholder interest in a highly distributed system.

In addition, in PR100 we developed dGen agents by income level to allow further downstream analysis of results by income level in support of recognition justice. Specifically, the dGen agents for PR100 were divided into four household income levels (residential customers):

- 0%–30% area median income (AMI)
- 30%–50% AMI
- 50%–80% AMI
- 80%–top% AMI.

Lastly, the experienced resilience of a self-controlled rooftop PV and storage system—particularly for remote and low-income customers as explored in Scenario 2 (Equitable Adoption)—represents an example of restorative justice because those customers were often the last to have power restored after a major storm such as Hurricane Maria. The modeling results show that higher income households will continue to adopt rooftop PV and storage systems through 2050 which could increase economic disparities across income groups over time due to the long-term economic benefits associated with adopting rooftop PV and storage.

7.3 Inputs and Assumptions

dGen uses extensive input data, as shown in Figure 114 (page 190) from various detailed geospatial data sets including population, zoning, and renewable resources (e.g., demographics). As shown in Section 4.1.2 (page 65), dGen in this case focused most heavily on using the provided solar data but also the rooftop technical potential calculated for Puerto Rico by Mooney and Waechter (2020). This was combined with what was known about demographics in Puerto Rico from the same rooftop study (Mooney and Waechter 2020). Note that for the contiguous United States, dGen has recently added access to parcel-level data to more accurately model the buildings in a region and then tie that modeling to various demographic characteristics. However, that is not possible in Puerto Rico, where NREL does not have adequate parcel-level data.

It is important to state that even though dGen requires a great deal of detailed inputs, the structure and limitations of the distribution grid are not incorporated in the model. Therefore, once this portion of the modeling creates an adoption level for rooftop PV, another analysis within PR100 determines the distribution upgrades needed to host that level of PV capacity and battery capacity. These results are described in Section 11 (page 347), but they heavily depend on the outputs of this rooftop modeling. In addition, dGen also incorporates the detailed hourly modeling of load data as described in Section 5 (page 117).

7.3.1 An Agent-Modeling Based Breakdown of the Puerto Rico Population

This section describes the various inputs used in dGen and focuses on those that are unique to Puerto Rico. Other key inputs are included as significant drivers (e.g., financial and incentive assumptions).

7.3.2 General dGen Inputs

Various financial assumptions relate to the distributed technologies that impact the calculation of adoption economically. This fact is particularly relevant as we seek to discount future costs and the value of the energy produced back to the present day. The values used for the financial analysis align with our typical assumptions over longer periods—for example, recent inflation might be high, but we are looking out over the lifetimes of projects installed currently.

- **Inflation Rate:** 2.5% throughout (long-term average).
- **Discount Rate:** 5%.
- **Utility Rates:** There are several residential retail rates depending on income levels in Puerto Rico. Those were assigned to appropriate agents in dGen (described below) and escalated. These rates (combined with the export compensation) form the basis of the bill savings for customers.

- Export Compensation: The dGen analysis assumes full net metering through 2050.
- **Utility Rate Escalation:** 4% based on long-term U.S. Energy Information Administration averages. Note that utility rates used vary by the breakdown of the agents for the project as defined below.

7.3.3 System Capital Costs

For Puerto Rico, the local rooftop PV and storage costs vary from averages for CONUS. Interestingly, there does not seem to be a documented collection of historical cost data for Puerto Rico; it would be valuable for stakeholders to gather those data, particularly as the rooftop PV and battery market in Puerto Rico is large for the population of Puerto Rico. To this end, the PR100 project team has been coordinating with the University of Puerto Rico at Mayagüez to gather costs across the Commonwealth. When released, those results will add to the existing documentation. Note that stakeholders for the study anecdotally report lower or higher prices with significant uncertainty over time and location. The costs used for dGen modeling in PR100 are included in Table 27, and utility-scale costs are reported in Section 10.

Table 27. Costs Used for Rooftop PV and Storage Systems

Cost Category	Cost	Source
2023 PV costs	\$3.185/W system cost for PV system	Vivienda estimates
Distributed battery costs	1,277 \$/kwh	Vivienda estimates
PV fixed operation and maintenance (O&M) costs	25.5 \$/kw-yr	NREL ATB: Distributed PV[a]
Battery O&M costs	87.7 \$/kw-yr costs for 2023; includes battery replacement anticipated in Year 10	NREL ATB: Distributed Battery[b]

[a] "Residential PV," NREL, https://atb.nrel.gov/electricity/2022/residential_pv (NREL 2022b)

[b] "Residential Battery Storage," NREL, https://atb.nrel.gov/electricity/2022/residential_battery_storage (NREL 2022b)

Future cost reductions match the forthcoming 2023 ATB cost reductions shown in Figure 117 for the moderate reduction case for PV costs and Figure 118 for battery storage costs. Note that these are just the system costs (rooftop PV and battery storage) and do not include costs for improving the distribution grid nor other necessary changes to integrate this distributed PV and storage resource onto the grid.

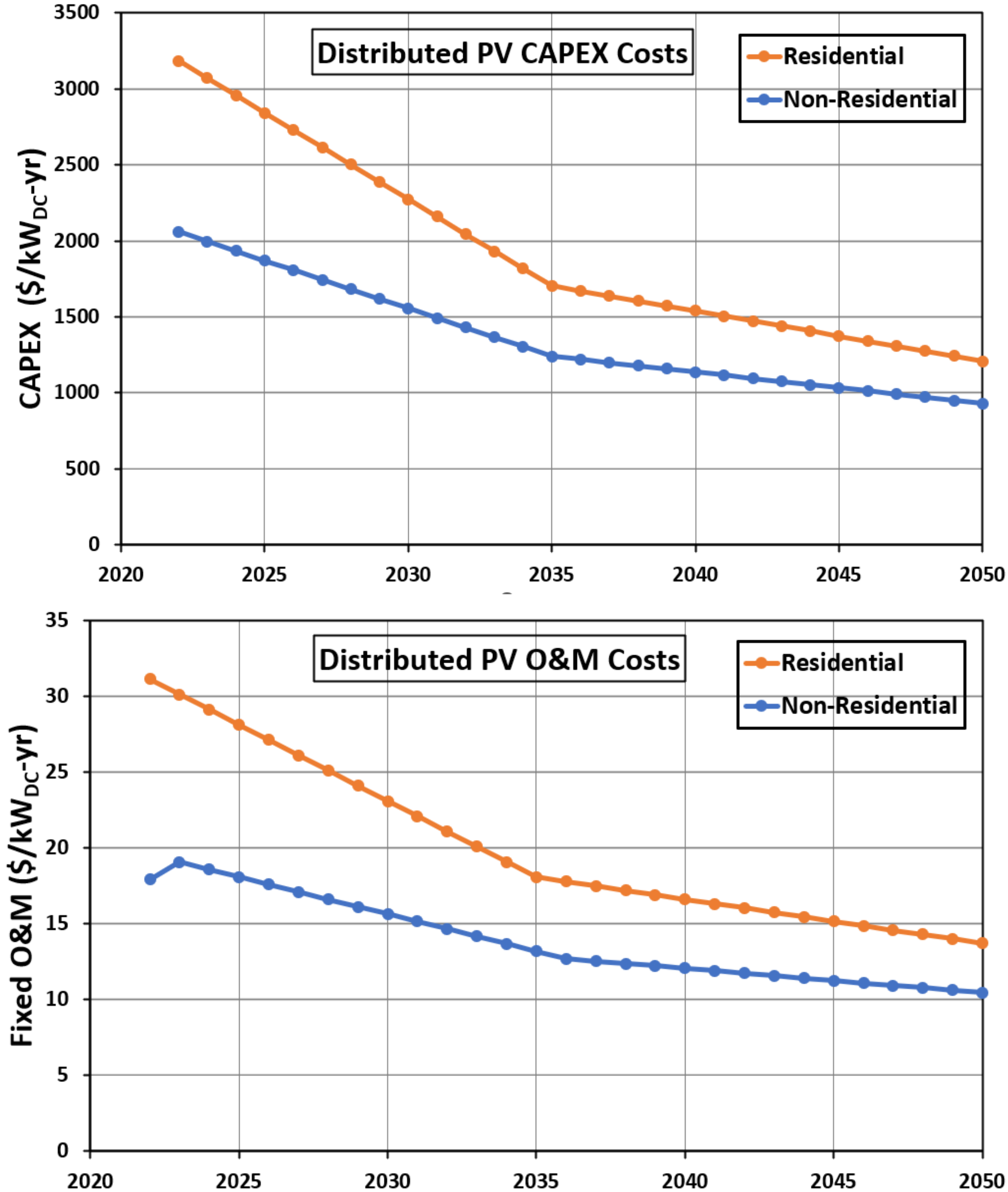


Figure 117. Distributed PV CapEx and O&M cost projections

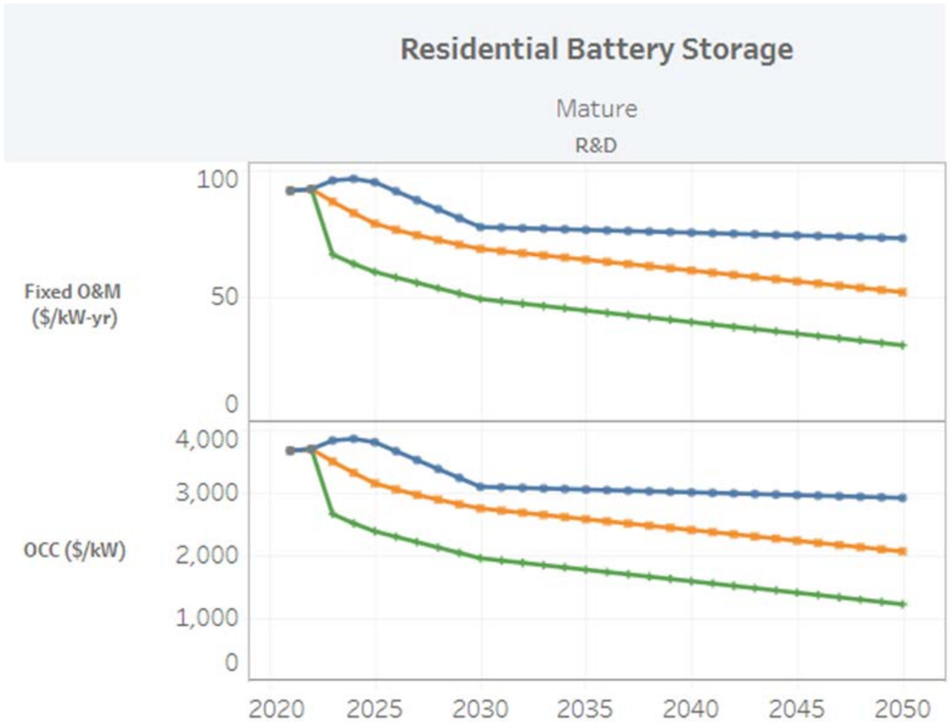


Figure 118. Future cost projections for residential battery storage

Source: NREL (2022b)

We use the ATB Moderate cost improvement scenario to calculate CapEx cost declines—not the starting point. (blue = conservative, orange = moderate, green = advanced)

7.3.4 Rooftop-Specific Inputs

Before PR100, an analysis was conducted to assess (1) how much rooftop space is available in Puerto Rico and (2) how much of that space is on low-income residential, high-income, commercial, and industrial buildings. That analysis (Mooney and Waechter 2020) used lidar data and complex image analysis to determine the size, orientation, and location of the available rooftops using data from 2015 to 2017. Lidar data were intersected with census demographics tables of household counts by income, tenure, and building type. This analysis resulted in a complex set of data that relates the rooftop availability and the demographics across the complex geometry of Puerto Rico. Section 6.1.3 reviews the details of the potential for rooftop PV and storage available in Puerto Rico by income group.

The total capacity of over 20 GW_{DC} of potential rooftop capacity is significant compared to both what is deployed in each scenario (maximum of ≈6 GW_{DC}) and the total typical load in Puerto Rico (3 GW). Note that within dGen some additional restrictions on available rooftop were included such that the model was able to tailor the available rooftop capacity to remove rooftop area not really feasible to be deployed. These restrictions in the model reduced the potential significantly but remains still significantly higher that it did not limit the deployment across scenarios.

7.3.5 Historical Adoption Data

dGen creates a series of adjustments for the rate of adoption and the Bass diffusion curve based on historical adoption. For the contiguous United States, sources for such data included the U.S. Energy Information Administration. For Puerto Rico, the best data source is the quarterly report that LUMA files with PREB to capture the number of installed systems and the amount of installed distributed PV capacity (Figure 119); we used the data in that report[117] to calibrate the adoption rate and starting point for dGen.

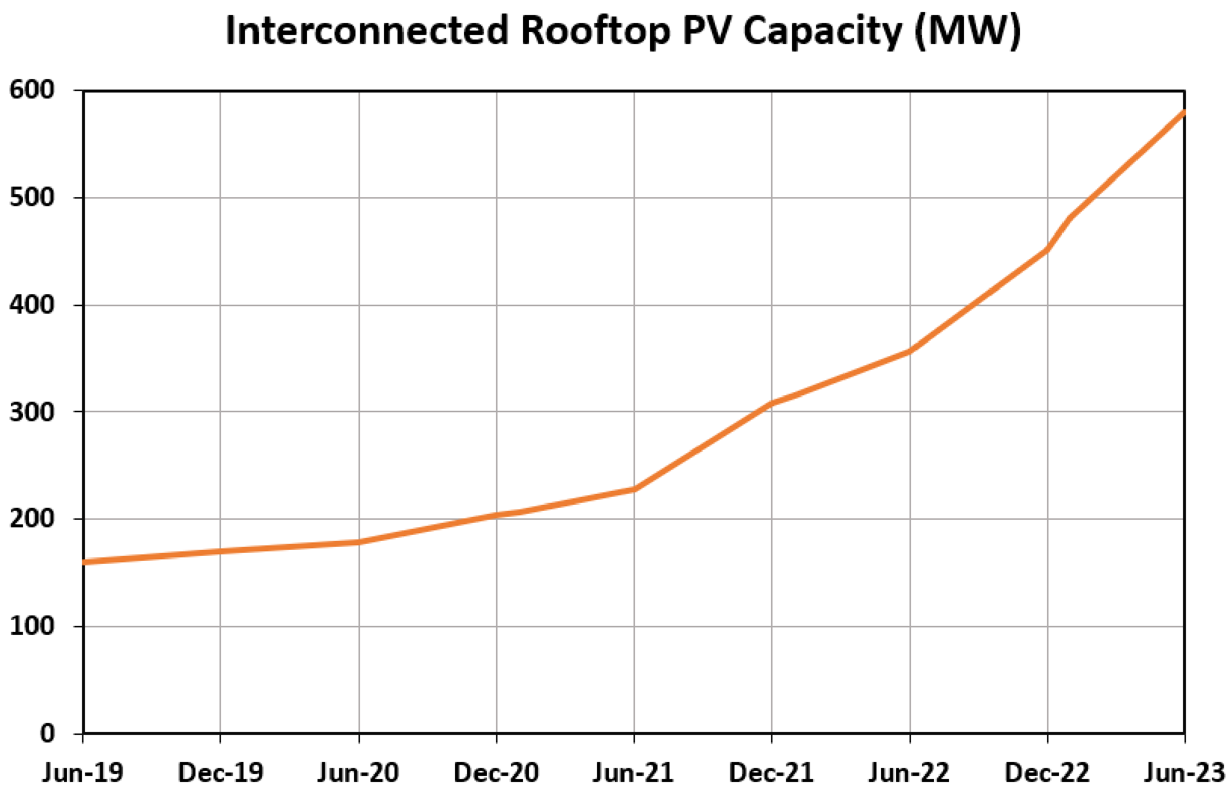


Figure 119. Interconnected rooftop PV capacity (MW) as reported being interconnected by LUMA

Source: LUMA (2023d)

The acceleration of the rate of interconnection by LUMA over recent months affected our modeling results, particularly in the near term. In addition, several uncertainties related to these data should be considered:

- It is difficult to separate systems that were installed before LUMA started collecting data from systems just now being interconnected. We assume the data reflect the rate of adoption particularly for the last 3-month period as the backlog of customers waiting for interconnection catches up.
- A forthcoming report from University of Puerto Rico at Mayagüez will present data indicating that there might be a non-trivial number of rooftop PV and storage systems that

[117] https://energia.pr.gov/wp-content/uploads/sites/7/2023/07/FY23-Performance-Metrics-by-Area-Renewable-and-DSM-Active-1.xlsx

are not interconnected and will not become interconnected. Owners of those residential buildings anticipate switching to those systems during an outage or running specific appliances using those systems. If those data are valid, it would skew the rate of adoption within dGen as well as our understanding of the economics of adoption in Puerto Rico. This would imply that the value of backup power as calculated and incorporated is likely still low as customers continue to purchase systems even without any net metering compensation for these systems.

7.3.6 Agent-Specific Inputs

All agents are available in every municipality. As shown in Table 28, agent number and amount were calculated based on total load for municipality and population breakdown (unless specific meter data were available to assign individual meters to each agent).

Table 28. dGen Agent-Level Variations

Agent Type[a]	Sector	Housing Type	Income Type	Critical Load Fraction	Value of Backup Power	Electric Service Tariff[e]
Agent 1	Residential	Single-Family, Owner Occupied	0%–30% AMI	75%	≈$200/yr[b]	LRS 109, LRS 110
Agent 2	Residential	Single-Family, Owner Occupied	30%–50% AMI	75%	≈$200/yr	LRS 109
Agent 3	Residential	Single-Family, Owner Occupied	50%–80% AMI	75%	≈$200/yr	LRS 109
Agent 4	Residential	Single-Family, Owner Occupied	> 80% AMI	50%	≈$200/yr	GRS 112
Agent 5	Residential	Multifamily, Owner Occupied	0%–30% AMI	75%	≈$200/yr	LRS 109, LRS 110
Agent 6	Residential	Multifamily, Owner Occupied	30%–50% AMI	75%	≈$200/yr	LRS 109
Agent 7	Residential	Multifamily, Owner Occupied	50%–80% AMI	75%	≈$200/yr	LRS 109
Agent 8	Residential	Multifamily, Owner Occupied	80%–120% AMI	50%	≈$200/yr	GRS 112

Agent Type[a]	Sector	Housing Type	Income Type	Critical Load Fraction	Value of Backup Power	Electric Service Tariff[e]
Agent 9	Commercial	N/A	N/A	80%	$40,000/yr[c]	GSS 211, GSP 212, GST 213
Agent 10	Industrial	N/A	N/A	100%	$700,000/yr[d]	GSS 311, GSP 312, GST 313

[a] The minimum PV system size has been set at 2.5 kW for all agent types.

[b] The value was quadrupled from the highest observed CONUS numbers because of the roughly 4x outage rate on the Commonwealth (Prasanna et al. 2021).[b] The value was quadrupled from the highest observed CONUS numbers because of the roughly 4x outage rate on the Commonwealth (Prasanna et al. 2021).

[c] The value was doubled from the highest observed numbers from the CONUS (Prasanna et al. 2021).

[d] The value was doubled from the highest observed numbers from the CONUS (Prasanna et al. 2021).

[e] LRS 109: Lifeline Residential Service (Customers with monthly consumption greater than 425 kWh);
LRS 110: Lifeline Residential Service (Customers with monthly consumption of 425 kWh or less);
GRS 112: General Residential Service; GSS 211: General Service at Secondary Distribution Voltage Commercial; GSP 212: General Service at Primary Distribution Voltage Commercial; GST 213: General Service at Transmission Voltage Commercial; GSS 311: General Service at Secondary Distribution Voltage Industrial; GSP 312: General Service at Primary Distribution Voltage Industrial; GST 313: General Service at Transmission Voltage Industrial (LUMA 2023).

The division of income categories reflects the rooftop PV potential analysis done previously and discussed in Section 3 (page 38). The critical load fractions were determined by conversation with experts and feedback from the advisory committee. They may seem high compared to other systems, but outages are frequent and long duration in Puerto Rico leading many residential customers to want to be able to use most loads during these longer outages.

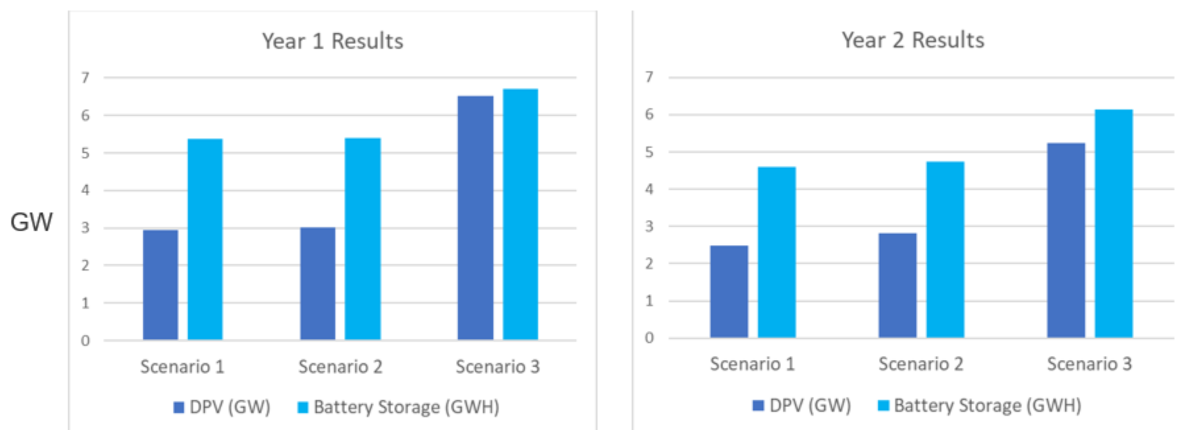
The value of backup power was an extension of prior work done for CONUS that combines the frequency of outages with surveys taken to determine a value for a typical set of outages. This methodology was discussed in the Storage Futures distributed storage report (Prasanna et al. 2021). This methodology combines survey data regarding willingness to pay for backup power and historical data on outages around the CONUS.

Both the critical load fraction and the value of backup power are highly uncertain values due to the length of historical and ongoing outages in Puerto Rico. Where the CONUS typically has 2 hours of outage per year (or less in many parts of the CONUS), Puerto Rico can have month-long outages. During that period, some stakeholders indicate they really want everything to work (critical load fraction = 100%). Similarly, even though we significantly increased the value of backup power over the highest value calculated for the CONUS, the lack of survey data and our perception of consumer sentiment indicates that perhaps even this high number (by CONUS standards) is too low.

7.4 Results

In this section, we present results for all relevant combinations of scenarios and variations. Note that because dGen modeling does not consider land, the land use variations within the scenarios (Less Land and More Land) are not relevant to these results. Therefore, we indicate Less Land, but results for the More Land variation would be identical. For the rooftop PV and storage results, we focused on the variation between Scenarios 1, 2, and 3 (defined in Section 6) as well as the load variations (which drive larger rooftop systems to be adopted) but not on the land variations. In this section, we present the year-by-year deployment of rooftop PV and storage (both energy and capacity) for each scenario as well as maps indicating where within Puerto Rico this adoption is located (both in total and per electricity customer).

Before we present the final results, it is valuable to compare results from our initial PR100 results shared at the end of Year 1 of analysis (Blair et al. 2023) and these final results. In Figure 120, we plot the initial 2050 results for Scenarios 1, 2, and 3 with Mid case loads and the same results now. The figure shows that the difference in PV deployment between Scenario 1 and Scenario 2 grows in the final results. In addition, the amount of distributed PV and storage in Scenario 3 decreases in the final results. There is more final PV capacity for Scenario 2 than initially because the agent definitions and the municipalities included in Scenario 2 have changed. Next, because in the final analysis the rooftop systems were defined to meet only the critical loads of the building (initial analysis had rooftops meet the entire load of the Commonwealth), we see that the final results deploy less PV and battery capacity for Scenario 3.



Year 1 2050 results for distributed PV and storage modeling for Scenarios 1, 2 and 3.* **2050 distributed PV adoption levels final results (Year 2)**

Figure 120. Comparison of Year 1 (initial) and Year 2 (final) rooftop PV capacity results.

We initially defined four scenarios: Economic, Critical, Equitable, and Maximum. Year 1 results showed that Scenario 1 was inclusive of Scenario 2 (Critical), so we narrowed analysis to three scenarios in Year 2. Here we show Year 1 results transformed to allow comparison with Year 2 results (with original Scenarios 1 and 2 combined into Scenario 1 [Economic and Critical]; Scenario 2 is Equitable, and Scenario 3 is Maximum).

Figure 121, Figure 123, and Figure 124 show the build-out through 2050 for rooftop PV and storage by scenario and variation. Specifically, each scenario has a variation for load (Mid case and Stress). Typically, the Stress load scenario augments the amounts of PV and storage that are deployed because the load for each agent is larger—therefore, the critical load is larger, and so the model builds more rooftop capacity to meet those loads. Figure 121 shows the cumulative rooftop PV capacity for all the scenarios in a single chart. Note that as we saw in Figure 120, Scenarios 1 and 2 both track much lower than Scenario 3 as designed. The Economic Adoption scenario (Scenario 1) with a growing load (the Stress load) actually results in higher levels of distributed PV than Scenario 2 (Equitable Adoption) with the Mid case load. We note that the maximum deployment (to meet critical loads) is ≈6 GW, which is far less than the Puerto Rico-wide 20 GW of technical potential so well within the need to put PV on every square inch of every roof.

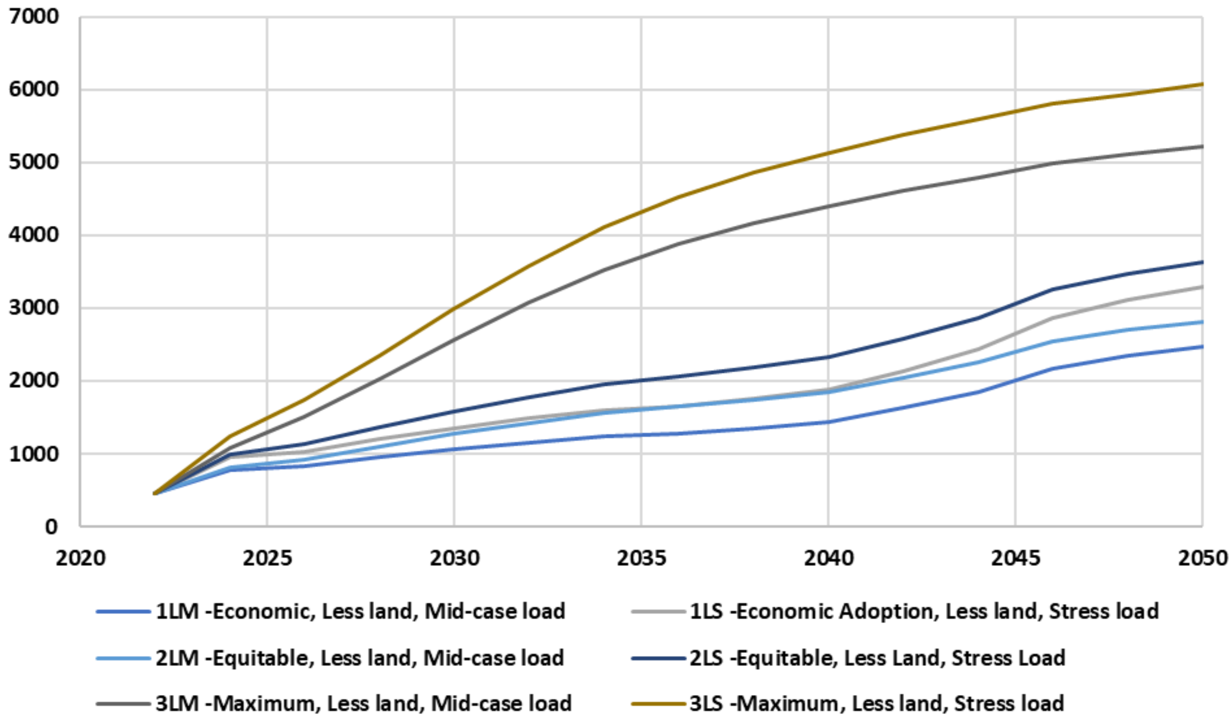


Figure 121. Cumulative rooftop PV capacity (MW) for each scenario

Figure 122 shows the generation from each of the modeled PV penetration levels as well as the annual Mid case and Stress load trajectories through 2050. When viewed in this annual way, it demonstrates that the load unmet by distributed PV generation is dramatically lower for Scenario 3 than Scenario 1. Note that this annual graphic does not reflect hourly power flows in which daytime rooftop PV generation flowing back onto the grid could be much larger than the load during those hours.

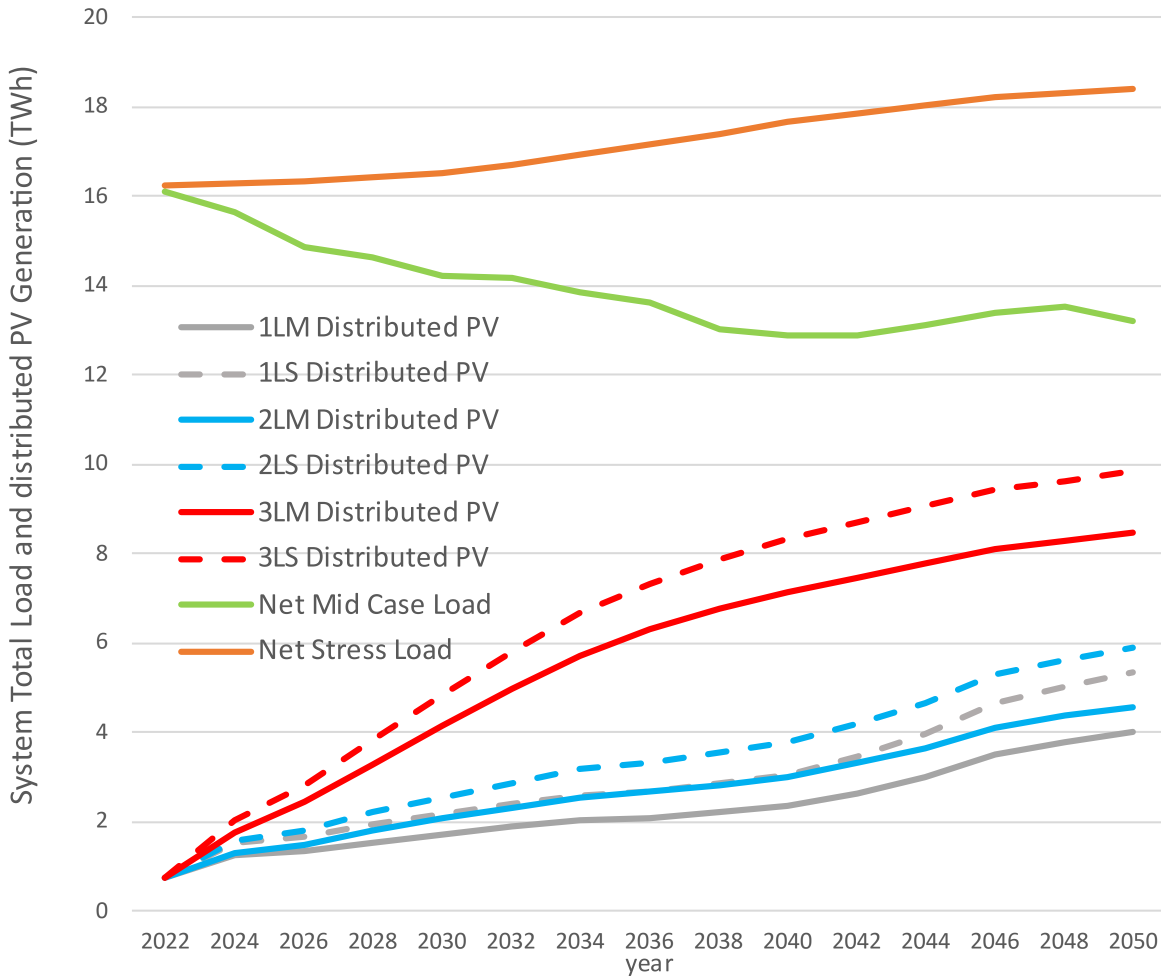


Figure 122. Rooftop PV generation in six scenario variations compared with net load forecast variations (Mid case and Stress)

Conversely, Figure 123 shows the amount of storage power (MW) installed with the rooftop PV. Storage power follows a pattern similar to the PV penetration, with Scenario 3 typically being higher than Scenario 1 or 2. Note that the shape of the battery power is more concave than the build-out of the PV capacity; our explanation for this is that rooftop PV and batteries are currently sized to cover the entire load of the building while our inputs size them more for critical loads for each agent.

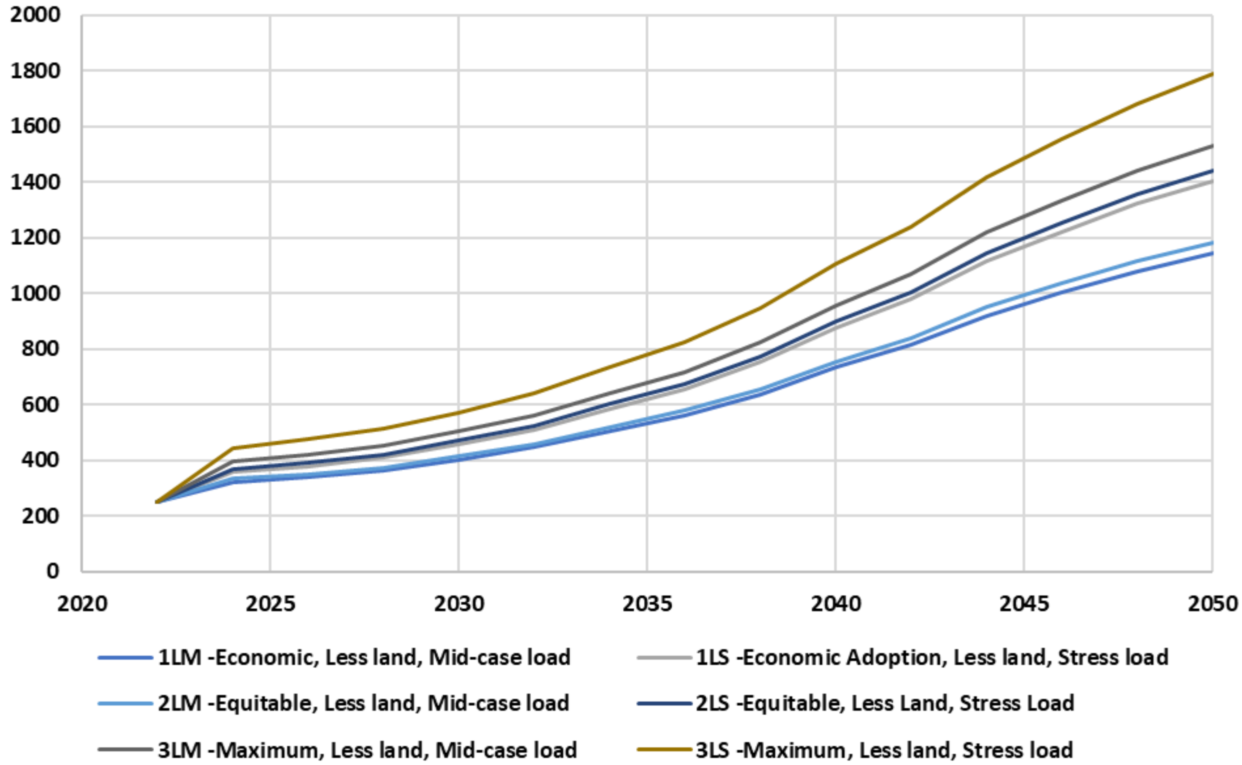


Figure 123. Cumulative distributed battery storage power (MW) by scenario

Figure 124 is similar to the battery power, but it shows the battery capacity (usually represented as MWh). This metric indicates how long the battery can output the same amount of power. For example, a 10-kWh battery can output 2.5 kW for 4 hours. As Figure 124 shows, the relative position of the megawatt-hour storage deployment maps similarly to the battery power in Figure 123.

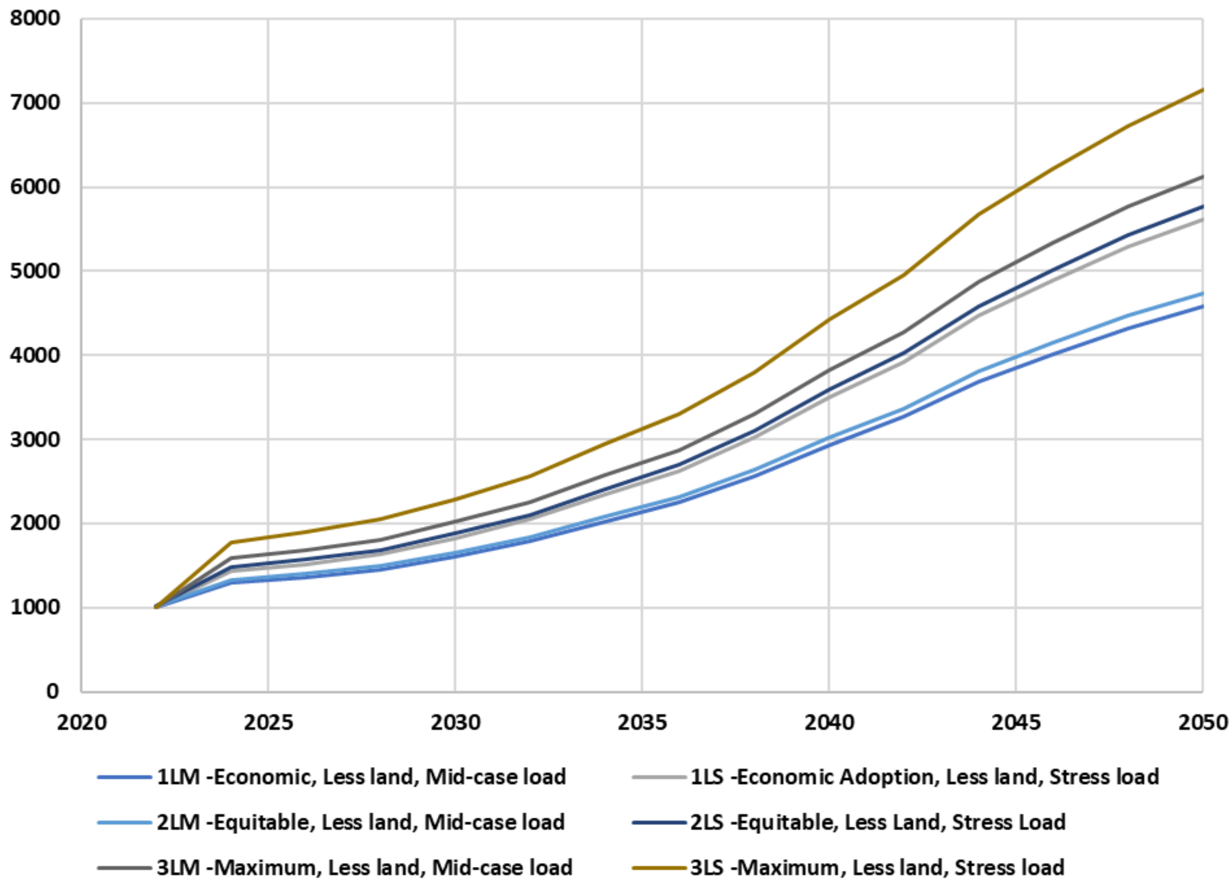


Figure 124. Cumulative distributed battery size (MWh) by scenario

The next several maps (Figure 125 through Figure 127) represent the installed capacity for several of the scenarios by municipality. These maps indicate the total capacity by municipality. Further down, we normalize those data for the number of electric customers. However, the total amount is also important because we seek to see what size of potential markets in specific cities and neighborhoods as well as when other analyses want to summarize the impact on the distribution grid because of rooftop PV-generated electricity flowing back onto the grid during the day. As the figures move from Scenario 1 to 2 to 3, the amount of rooftop PV capacity increases for all regions with less of a focus on large cities in Scenario 3 than in Scenario 1.

It emerges that the San Juan municipality dominates the amount of installed capacity often by several orders of magnitude. This is primarily because of the population density in this municipality but also because of the additional wealth agents that likely install larger rooftop PV and storage systems. Conversely, one of the uncertainties in this municipality that we would explore in the future is more unconventional mounting locations such as roadways, carparks, and outdoor gathering areas. In addition, this high level of penetration in the San Juan municipality results in a concentrated amount of power flowing back into the distribution and transmission grid.

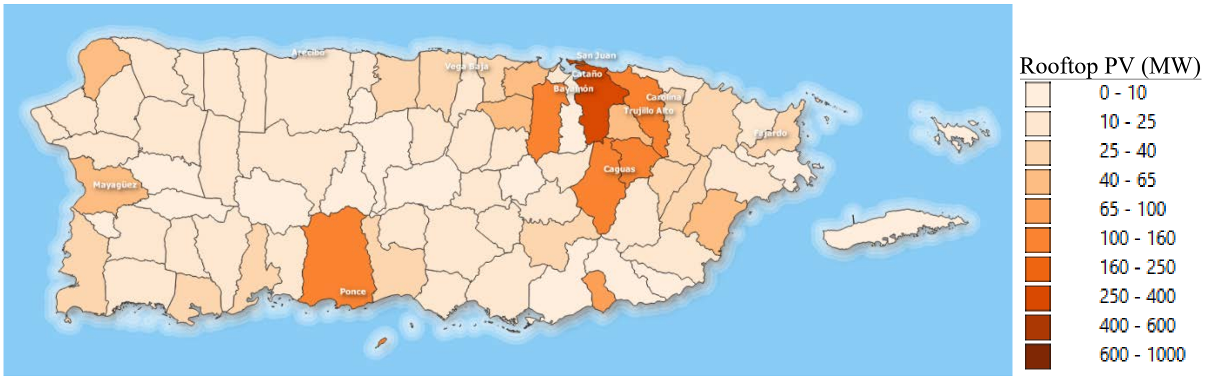


Figure 125. 2050 rooftop PV capacity for Scenario 1 with Mid case load (1LM)

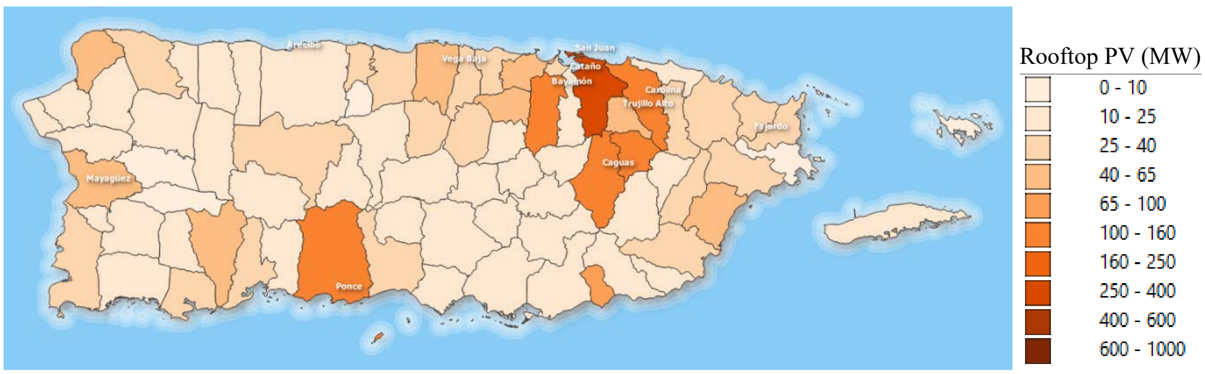


Figure 126. 2050 rooftop PV capacity for Scenario 2 with Mid case load (2LM)

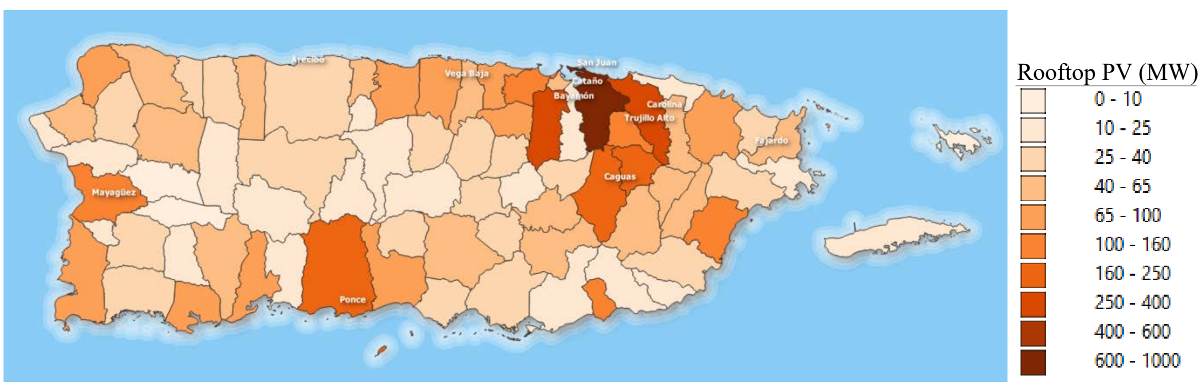


Figure 127. 2050 rooftop PV capacity for Scenario 3 with Mid case load (3LM)

Similar to these maps of the total capacity, we present additional maps for the same scenarios that are adjusted for the population density. Figure 128, Figure 129, and Figure 130 also represent the total rooftop PV capacity by municipality for a Scenario 1, 2, and 3 example; however, the values are now divided by the number of electric customers in that municipality using data shared by LUMA.

As with the total capacity maps above, the per-customer maps also follow similar trends with Scenario 1 having the least amount per municipality and Scenario 3 having the most. Note that San Juan municipality, although still important, does not dominate the results. In fact, all scenarios have municipalities in 2050 that have more distributed PV per customer than San Juan.

Figure 128 has an additional important result: between Figure 125 for Scenario 1 and Figure 126 for Scenario 2, there is more PV capacity in the regions that align with the municipalities that are deemed remote or most vulnerable to storms. Regions in the central mountains in particular emerge as having higher levels of PV capacity per customer. The map of the specific Scenario 2 regions (where every residential customer adopts rooftop PV and storage by 2050) is inset to verify.

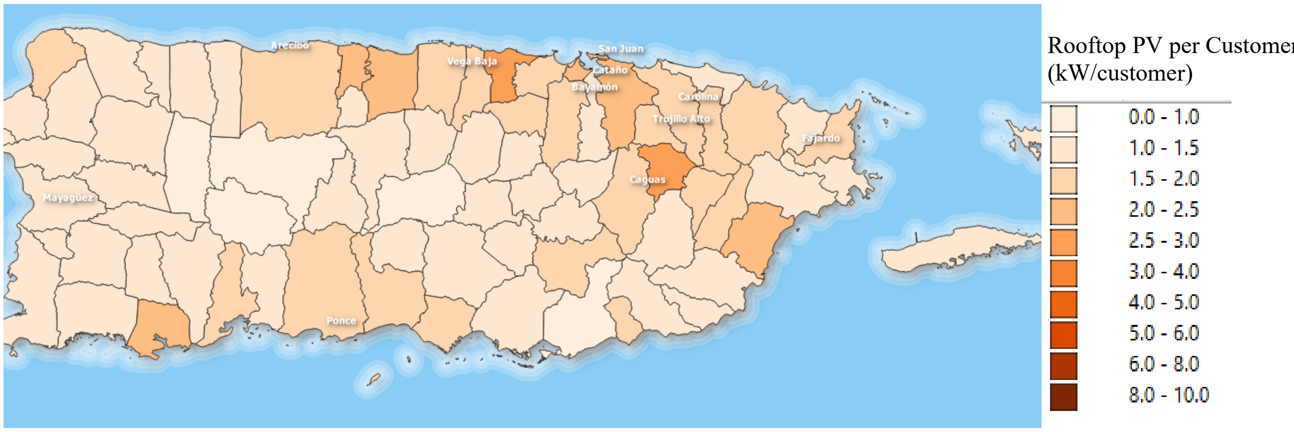


Figure 128. 2050 Rooftop PV capacity per customer for Scenario 1 with Mid case load (1LM)

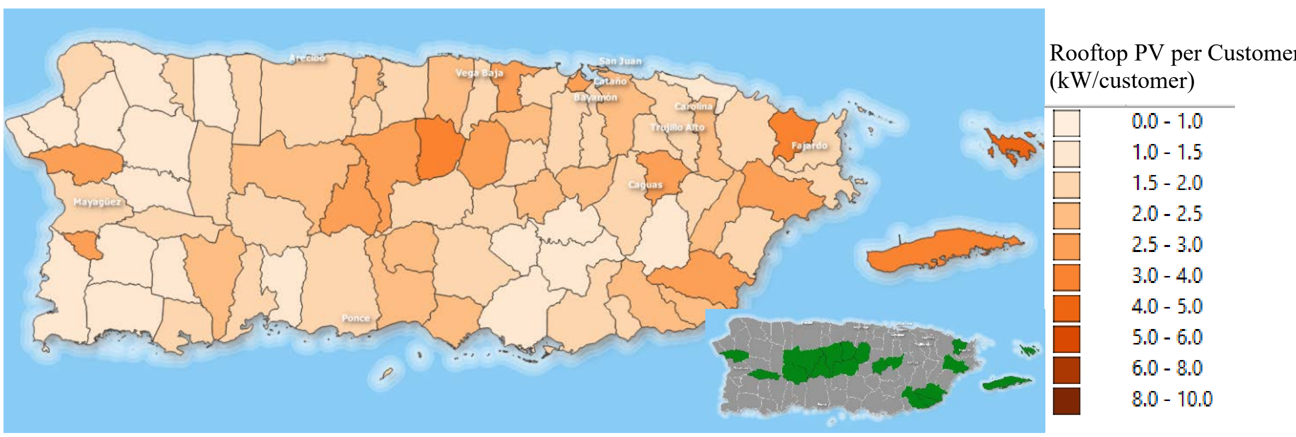


Figure 129. 2050 rooftop PV capacity per customer for Scenario 2 with Mid case load and net metering (2LMNet)

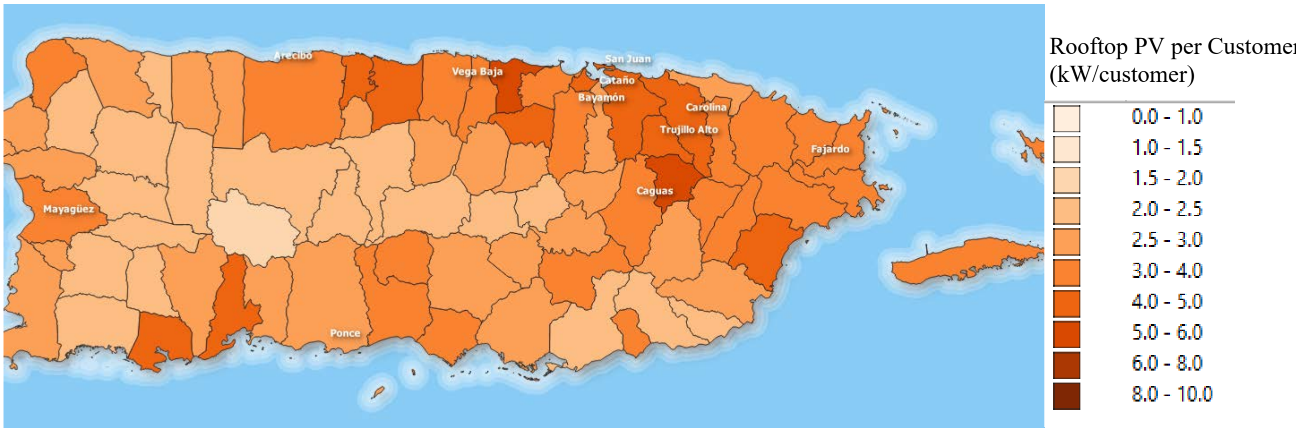


Figure 130. 2050 Rooftop PV capacity per customer for Scenario 3 with Mid case load (3LM)

7.5 Microgrid Relationship to Rooftop PV and Storage

Distributed PV and storage systems that can disconnect from the grid provide resilience to households by allowing them to keep the power on during a grid outage. A microgrid is a group of interconnected loads and DERs that act as a single controllable entity with respect to the grid.[118] Like individual buildings, microgrids can connect and disconnect from the grid to operate in grid-connected or island mode. Connecting groups of buildings into microgrids can improve customer reliability and resilience to grid disturbances at the community level. We are discussing microgrids here because we want to highlight the fact that, while the dGen model is focused on adoption of rooftop PV and storage by building, the future reality of deployment might be that a fraction of the rooftop PV capacity deployed is actually more economic or more effective to build across a set of buildings as a microgrid.

We also want to highlight the prior work assessing microgrid locations in Puerto Rico. In 2019, Sandia National Laboratories conducted a microgrid analysis for Puerto Rico (Jeffers et al. 2018) to identify potential microgrid locations to increase resilience. The analysis was complex, exploring critical and vulnerable locations and suggesting locations that might benefit from a microgrid.

Figure 131 shows approximate locations for up to 159 microgrids identified by (Jeffers et al. 2018). In total, the analysis suggested a total capacity of 343 MW for critical load and 398 MW for noncritical demand. The critical load spread across Puerto Rico would be far less than the rooftop potential (≈20 GW) across Puerto Rico (Mooney and Waechter 2020) and also less than the deployed rooftop PV across the various scenarios. Several community microgrids have been

[118] "Microgrids," NREL, https://www.nrel.gov/grid/microgrids.html.

successful in Puerto Rico,[119,120] and several more are being built (e.g., Centro Médico Microgrid in San Juan[121]).

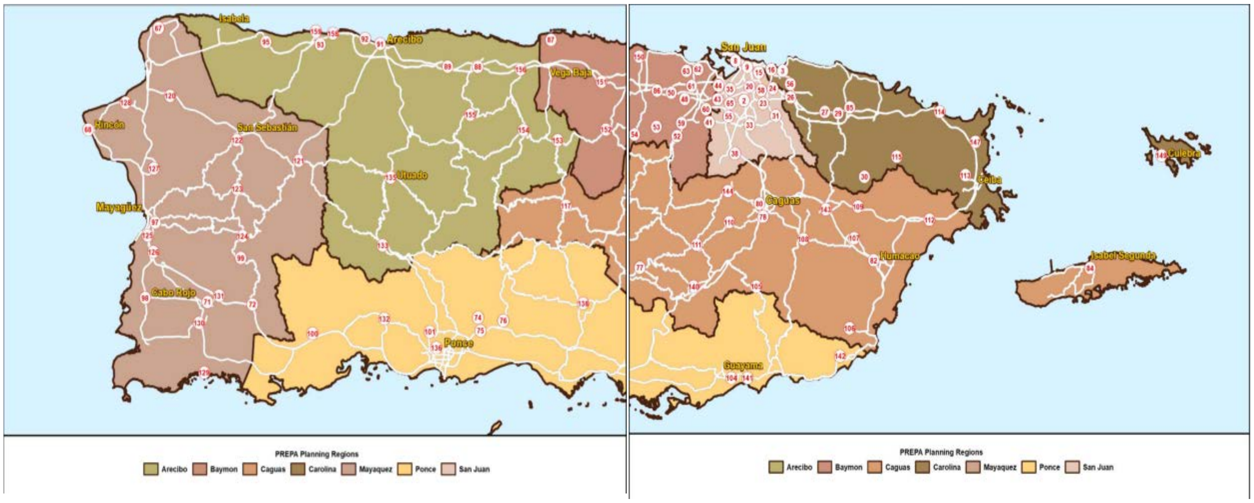


Figure 131. Approximate locations for up to 159 microgrids identified by Jeffers et al. (2018)

PR100 analysis focused on rooftop PV and storage deployment for individual buildings, but some of the new capacity to be added on homes and businesses in years ahead will likely be connected together as microgrids rather than all on individual roofs. These microgrids could include rooftop PV and storage built on large community centers, carports, or other structures next to buildings with insufficient rooftop space. Additional analysis likely would show that some of these microgrids would make economic sense and provide similar levels of local resilience as individual rooftop systems. They may require significant additional infrastructure locally and with the utility as well.

[119] "Adjuntas Pueblo Solar," Casa Pueblo, https://casapueblo.org/la-increible-hazana-de-casa-pueblo/.
[120] "Solar Microgrid Keeps the Lights on in Castañer, Puerto Rico During Hurricane Fiona," IREC, https://irecusa.org/blog/local-energy-climate-solutions/solar-microgrid-keeps-the-lights-on-in-castaner-puerto-rico-during-hurricane-fiona/.
[121] "CDBG-DR Helps Fund Green Energy for Resilience in Affordable Housing and Medical Facilities," U.S. Department of Housing and Urban Development, February 22, 2023, https://www.hud.gov/states/puerto_rico_virgin_islands/stories/2023-02-22.

8 Integrated Capacity Investment

Tom Harris[1], Cameron Weiner[1], James Morris[1], Clayton Barrows[1], Joseph McKinsey[1], and Surya Chandan Dhulipala[1]

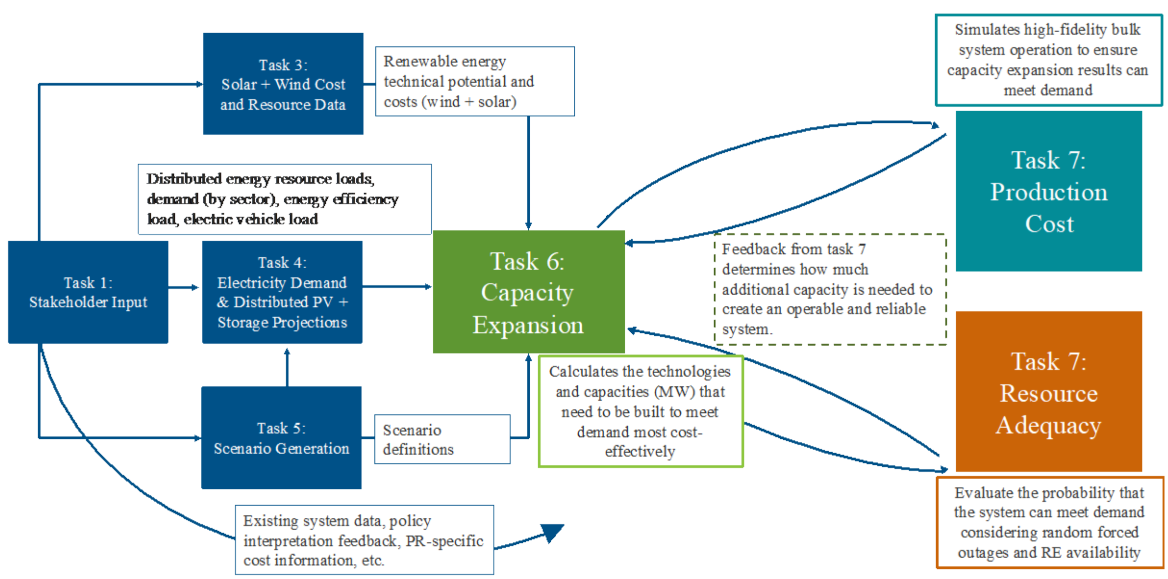
[1] National Renewable Energy Laboratory

Section Summary

The purpose of the capacity expansion and resource adequacy modeling performed for PR100 was to identify for each scenario the least-cost[122] approaches to meeting Puerto Rico's statutory objectives for the electric sector and ensure they account for adequate generation and transmission resources for a reliable bulk power system. This section documents the key findings, methods, assumptions, results, and interpretation of the results of these analyses. As illustrated in the figure below, the analyses integrated the output data and findings of prior tasks, including the following:

- Renewable energy technical potential data (Section 4, page 59)
- Net electrical load projections from the end-use loads, energy efficiency, and electric vehicle adoption (Section 5, page 117)
- Scenario definition and configurations (Section 6, page 173)
- Distributed renewable electricity generation impact on load from the distributed solar photovoltaics (PV) and storage adoption projection (Section 7, page 186).

The figure below highlights capacity expansion (Task 6) and production cost and resource adequacy (Task 7) analyses discussed in this section. These analyses were influenced by stakeholder input, which we gathered and documented as part of our stakeholder engagement activities in Task 1[123] (discussed in Section 2, page 11) and incorporated into scenario definition and analysis.



[122] By "least-cost," we mean the lowest-cost combination of resources (generators, wires, and so on) that together have the energy production capacities to meet system electricity demand at all times. Some stakeholders pushed back against this approach because it does not account for complexities such as social or environmental costs.
[123] All PR100 tasks are listed in Figure 2, page 7.

Key Findings

- To meet the near-term 40% renewable portfolio standard (RPS) and system reliability needs, multiple gigawatts of renewable generation and storage capacity are needed by 2025 (Section 8.4.2.1).
- Planned tranches are insufficient to reach 40% renewable energy generation by 2025, assuming utility-scale PV or similar (Section 8.4.2.1).
- The total (beyond 2025) of the planned generation tranches generally aligns in scale with scenario results that achieve a 40% renewable RPS and retirement of coal, but the models require more storage power and energy capacity than planned in the tranches. We see much larger jumps in utility-scale capacity procurements to meet the 2025 and 2050 RPS requirements than to meet the 2040 RPS requirement.
- Across the scenarios, we do not see deployment of offshore wind, ocean thermal energy conversion (OTEC), or hydrogen in the model (Section 8.4.3).

Considerations

- Accelerated approval process and immediate ramp-up of procurement and implementation of renewable generation capacity and storage capacity are needed to support achievement of the near-term RPS goals.
- Defining future generation procurements (future tranches) in units of generation (MWh) rather than capacity (MW) would provide greater clarity in the procurement process.
- A higher RPS requirement and additional interim requirements could support better planning, smoother transitions, and lessened risk of not achieving the 2050 goals. Pairing with noncompliance consequences would help ensure requirements are met.
- Further guidance and regulations on renewable energy certificates will clarify the contribution of distributed renewable generation toward the RPS.
- Relative levelized costs of different renewable generation technologies are key drivers for the results of the capacity expansion model. As renewable energy and storage technologies develop, the levelized costs of these and other nonmodeled technologies may change, driving different long-term build decisions. This study should be reevaluated with up-to-date technology costs over the years.

8.1 Methodology

The primary objective of the capacity planning task in PR100 was to identify the expected least-cost portfolios of utility-scale generation sources that both meet Puerto Rico's projected utility system electric loads and comply with the Puerto Rico Act 17 RPS requirements for each distributed generation adoption scenario and land use and load projection variations defined by the scenarios task.

This was done by performing a least-cost optimization of the Puerto Rico bulk power system generation and transmission needed to meet the system load for each scenario and variation using the Engage modeling tool and capacity expansion web application and the National Renewable Energy Laboratory's (NREL's) high-performance computing infrastructure. As detailed in Section 6 (page 173), the scenarios and their variants were defined primarily by different assumptions about rates and quantities of distributed energy resource adoption, then by what land would be made available for building utility-scale renewable energy generation, and then by assumptions about future electrical system loads—including energy efficiency measure implementation, electric vehicle (EV) adoption, and charging. All scenarios were constrained uniformly by projections of what utility-scale generation technologies were thought likely to be available and at what costs and in what ownership arrangements.

Capacity expansion modeling begins with model representation of existing and projected loads and generation and transmission facilities representative of the current utility system, and generation and transmission facilities thought certain to be installed in future (usually near-term) years and dates by which certain assets are expected to be retired.

Potential technologies are added to this baseline system model representation for the model to evaluate for implementation to meet existing or arising generation inadequacy, meet growing load, make up for generation that may be retired, or meet constraints on the types of technologies that can be used for generation as might be required by a renewable portfolio standard (RPS).

The technologies represented in the model are each constrained by high-level operating characteristics such as (for variable renewable energy technologies) hourly resource availability, ramping rates, variable operating costs that represent wear and tear and fuel costs, and—in their capacities—either fixed capacities for existing assets or capital and/or annual fixed operating and maintenance costs proportional to the technologies' power dispatch capacities and, in the case of storage technologies such as batteries, proportional to their energy storage capacities.

Though the baseline model is the same across all scenarios and variations, the fixed technologies representing distributed energy resources (DERs) differ across scenarios, variations, and years based on results of the distributed PV and storage agent-based modeling differing across these dimensions. Likewise, the technical potential locations for utility-scale variable renewable energy that are excluded—precluding the model from using them for implementation of new generation capacity—differ across scenario variants that vary land-availability. Finally, the end-use load differs across the load scenario variants.

For each scenario variant, the model was run starting with capacity expansion for 2025 with a constraint that requires 40% of the simulated generated electricity to come from renewable energy sources and requires the model to build new generation to meet this requirement if necessary. The model then looks for the least-cost combination of existing and new generation sources and merit order dispatch that can meet the load and the RPS constraint.

The model was then run for each scenario for 2028, using the combination of technology capacities that was built for 2025 plus any programmed new power system assets as the baseline 2028 system. The 2028 model is constrained to meet load, maintain the 40% RPS, and follow the PREB resolution and order fossil fuel generation retirement schedule (PREB 2020). The model then repeats this process every five years from 2030 to 2050.

This simulation process produces capacity expansion results for each of the 12 scenario variants for each of the 7 solve years (2025, 2028, 2030, 2035, 2040, 2045, and 2050). These 84 scenario-year results provide inputs to downstream PR100 analysis including production cost, system reliability, and economic impacts analysis.

8.1.1 Capacity Expansion Modeling

We modeled Puerto Rico's electric system from the perspective of the grid operator. Modeling from the perspective of the grid operator means that we represented costs and operating characteristics as the grid operator would see the costs. The impacts of these costs on Puerto Rico's economy and the rate payers are analyzed in Section 12 (page 401).

We used the Engage modeling tool to perform this analysis. Engage is a free, publicly available modeling tool built around Calliope,[124] a tested and well-documented open-source modeling framework for cross-sectoral energy simulation and planning. Based on the existing generation and transmission system and planned Tranche 1 generation—as well as scenario-specific distributed PV projections, load projections, and future potential technology parameters and options—the Engage modeling tool calculated the most cost-effective mix of generation and storage needed to meet all scenario constraints and Act 17 for each year.

The Engage model for PR100 represents the electric grid in Puerto Rico at the high-voltage 115-kV and 230-kV transmission system level. Generator units, demand, DERs, and other grid assets were aggregated to the nearest high-voltage substation, and candidate sites for new assets were either attached to or placed at those high-voltage substations in the model. High-voltage transmission was represented with current rated capacities for the model to factor in the limitations of the bulk transmission system when trying to meet load.

For each scenario, Engage analyzed years 2025, 2028, 2030, 2035, 2040, 2045, and 2050. We chose a 5-yr modeling cadence to reduce the time required to run full scenario simulations while still capturing the incremental build-out needs of the system due to load changes and the evolving RPS requirements. 2028 was also explicitly included to model the retirement of major fossil fuel assets including coal in 2028 as well as the tranche capacities planned through that year. Engage determined the most cost-effective technologies needed to meet the demand and scenario constraints by running each year incrementally. The results from the Year 1 run formed the baseline for the next year's run. For example, after running the 2025 run, the results from the

[124] See https://www.callio.pe/.

2025 run become part of the preexisting system for the 2028 run, and the 2028 run determines the additional capacity needed to meet the 2028 run load and scenario constraints.

Engage modeling runs were optimized over three representative periods at full hourly resolution and a 6-hr time resolution for the rest of the year. The three representative periods reflected the week with the day of peak demand, the 5 days of lowest total PV resource, and the week of highest PV resource. These specific representative periods were selected to best capture some of the extreme periods that would drive additional capacity build-outs and lead to more resilient and complete results. The actual calendar dates for each period are based on the specific inputs for that scenario and year.

8.1.1.1 Resource Adequacy

Resource adequacy (RA) studies evaluate whether a system's resources (generation and storage fleet) combined with demand-side and interchange contributions will be able to maintain reliable electricity service across a range of specified expected conditions and to an expected standard. RA studies have been used to support assessment of various regional resource assessment efforts as well as to support transmission planning activities.

Specifically, for each expansion scenario and year, we used the Probabilistic Resource Adequacy Suite (PRAS)[125] to simulate 10,000 Monte Carlo forced outage samples for generation and transmission components with historical forced outage rate data. The forced outage samples were then used to calculate the likelihood that enough generation, storage, and inter-regional transmission resources are available to meet projected electricity demands during every hour in the year. In addition, the RA calculations account for the availability of wind and PV resources based on the production profiles for utility-scale resources expanded with the Engage modeling tool and distributed resources adopted in Section 7.4 (page 199).

PRAS is a probabilistic model based on samples of pseudo-random forced (fossil-fuel-fired) generation and transmission outages and RE availability. However, PR100 has only a single year (2019) of temporally consistent renewable generation and electricity demand data. Therefore, the representation of renewable generation in PRAS is deterministic. Because the principal source of random variables in the PR100 model is fossil-fuel-fired generation outages—as fossil-fuel-fired generating units retire from service throughout the PR100 horizon—the PRAS results become increasingly deterministic. In 2050, when all fossil-fuel-fired generation units are retired, the only pseudo-random variables remaining in the PRAS model calculations are transmission outages.

In addition to evaluating the standard RA metrics of each expansion scenario-year, we use a sensitivity analysis to identify additional "ideal" capacity requirements needed to achieve industry-accepted levels of resource adequacy. For each expansion scenario and year, we incrementally add 50 MW of ideal capacity that is always available (zero forced outage rate) until the loss of load expectation (LOLE) is reduced to below 2.4. event-hr/yr. Depending on the interpretation of the often referenced "1 day in 10 years" metric (Carden et al. n.d.), a LOLE target of 2.4 hours per year can imply an equivalent or a less restrictive reliability target. However, we opted to use 2.4 event-hr/8760 because of the high historical forced outage rate of

[125] "PRAS: Probabilistic Resource Adequacy Suite," NREL, https://www.nrel.gov/analysis/pras.html.

the generation fleet (Stephen et al. 2022), and the clear definition and measurability of the hourly LOLE target. The total additional ideal capacity required to achieve 2.4 event-hr/yr of LOLE is added in the form of long-duration (10 hr) storage prior to 2050 and biodiesel generation in 2050.

8.2 Inputs and Assumptions

The inputs and assumptions for the capacity expansion model fall into the following categories:

- Scenario-based constraints
- Policy and regulatory constraints
- Demand projections
- Costs, capacities, and other operational constraints for the following:
    - The existing transmission and generation system
    - Capacity expansion technology options
    - Planned generation such as distributed PV and Tranche 1 projects.

The key inputs and assumptions we made for each of these categories are described in the sections below.

8.2.1 Policy and Regulatory Constraints

Across all scenarios, the model is required to meet Act 17 RPS goals and the retirement schedule published in the PREPA's 2019 IRP, Tables 5, 6, and 7, as amended[126] in the PREB resolution and order submitted on August 8, 2022 (PREB 2021a) (case number NEPR-MI-2019-0007) (Vega 2022). Regarding the tranche procurement schedule outlined in the PREB resolution and order, all scenarios included the tranche storage capacity requirements as minimum model constraints but did not include tranche generation capacity requirements.

For generation procurements, we constrained the model to least-cost optimize required technologies and capacities needed to meet the 40% RPS in 2025 and support the system continuing to meet the 40% RPS with the coal plant retirement in 2028.

Based on stakeholder feedback, we configured the model to count generation from distributed PV toward the RPS. Thus, the model least-cost optimized utility-scale generation buildout taking into account different levels of projected distributed PV adoption across scenarios. The utility and operator do not yet have policies, metering, or an accounting method in place to do so. Further guidance and regulations on renewable energy certificates will clarify the contribution of distributed renewable generation toward the RPS.

[126] Source of amendment information, letter to Ms. Anias Rodríguez Vega, Acting Secretary, Department of Natural and Environmental Resources (DNER) from Antonio Torres Miranda, Legal Affairs Director, Puerto Rico Energy Bureau (PREB) providing updates to Tables 5 (renewables procurement schedule), 6 (expected integration of renewables) and 7 (Retirements Authorized in the Approved IRP) of PREB's April 11, 2022 filing.

8.2.2 Existing Generation and Transmission

Puerto Rico's current electric system has 4.48 GW of operational utility-scale generation.[127] The fossil fleet represents 4.26 GW of the total system capacity and comprises approximately 1.63 GW of natural gas, 1.24 GW of fuel oil no. 6, 0.941 GW of diesel, and 0.454 GW of coal-powered generating units. The remaining 220 MW of utility-scale generation comprises 143 MW of solar, 75 MW of wind, and 4.8 MW of landfill gas.

The retirement schedule outlined in the PREB August 2022 resolution and order indicates that 355 MW of fossil fuel generating capacity will be retired by 2025, another 1,334 MW by 2028, and another 320 MW by 2030. In the capacity expansion model, we retire all remaining fossil fuel generation at the start of 2050.

LUMA provided us with the data for the existing generation and transmission system. The principal data sources from LUMA included load flow cases and the inputs to a production cost model it is using to inform the next IRP process. To minimize computational complexity, we aggregated all grid elements including buses, existing transmission, and generation to the 115- and 230-kV substation levels. The transmission network carrying capacities and line losses were provided by LUMA. To aggregate the transmission system data, we summed the capacities of all transmission components between two substations and calculated the line losses using the weighted averages of the resistance values from the aggregated lines. LUMA provided the PR100 project team with the operational and cost characteristics of existing generation in Puerto Rico. For the existing generation, we summed the capacities of units that are located at the same substation, use the same fuel, and are the same technology type (e.g., steam turbine or gas turbine).

8.2.3 Fuel Costs

For the existing fossil fuel generation fleet, we calculated Puerto Rico fuel costs through 2050 using baseline 2022-2023 fuel prices from LUMA[1] scaled proportionally to long-term projections from the U.S. Energy Information Administration (EIA). Biofuel costs were calculated by averaging historical Alternative Fuels Data Center B100 fuel costs from the Pacific region which includes costs from Hawaii. We chose to use these Pacific region costs that include the Hawaiian B100 costs as these costs factor in the cost of shipping B100 from the continent to an island. No fuel cost forecast scaling was applied to the B100 fuel costs. Figure 132 presents the fuel costs used in this study for each fuel type from 2025 to 2050. LUMA provided the PR100 project team with historical fuel data. These data are not publicly available.

[127] LUMA provided the PR100 project team with information on the existing Puerto Rico generation fleet. These data are not publicly available.

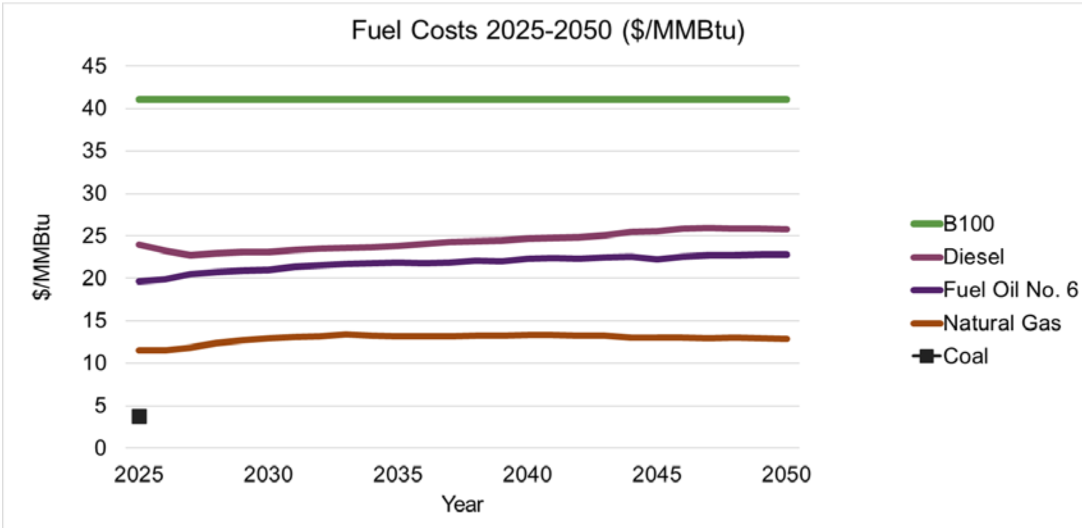


Figure 132. Fuel costs by fuel type 2025-2050 in $/MMBtu (2021$)

8.2.4 Demand Projections

To accurately represent demand in Engage, we used the hourly generation projections from 2025 through 2050 (Section 5.4.2, page 169) minus an estimated 2.5% high-voltage (115-kV and higher) transmission loss. We used the generation projections as opposed to the load projections because the capacity expansion model does not account for any transmission or distribution loses below 38 kV; therefore, by using the generation data minus the high-voltage transmission losses, the model is required to generate the appropriate quantity of electricity needed to meet the end-use loads.

The load task provided generation data at the municipality level. As noted in Section 8.2.2 (above), the Engage modeling tool represented the electric system at the 115- and 230-kV substation granularity. To translate the municipality-level data into substation-level data, we used data from LUMA's operational model, which provided load participation factors for each bus in the Puerto Rico electric grid. Load participation factors indicate the proportion of the total electric demand for each bus. After spatially locating each bus in the system, we used these load factors to attribute a portion of each municipality's load to each bus. We then summed the various loads attributed to each bus aggregated to a particular 115- or 230-kV substation to get a representative weighted load for that substation that could include portions of loads from multiple municipalities that the substation might service.

8.2.5 Distributed Photovoltaics Capacity Projections

The decisions to build distributed PV capacity are often driven by nonfinancial objectives. Thus, we modeled the distributed generation adoption as a separate decision process (documented in Section 7 (page 186). The distributed PV adoption results (documented in Section 7.4) were used in the capacity expansion model as fixed inputs that defined the projected distributed PV added to the system in each scenario-year across all residential and nonresidential sectors in each municipality. We disaggregated these municipality-level data to the substation level in the Engage modeling tool using the same load participation factor weighting process used for the municipality-level load data. Additionally, we created proxy generation profiles for distributed

PV based on solar resource data, generated by the solar resource task, from the centroid of each municipality.

We recognize that distributed storage could theoretically provide resources to support reliable and economic grid operations. However, we did not represent distributed storage in the capacity expansion model for two reasons. First, we understand that to-date distributed storage adoption decisions in Puerto Rico have principally been for local reliability/resiliency purposes, and we expect that a more reliable energy system would temper the need to adopt distributed storage. Second, the existing Puerto Rico net metering policies do not incentivize distributed PV and storage owners to provide stored energy back to the grid. Currently, there are no time-of-use rates in Puerto Rico, so selling excess behind-the-meter generation back to the grid offers the distributed PV owner the same rate at any hour of the day. This rate scheme makes selling excess behind-the-meter generation directly to the grid more cost-effective than storing the electricity and discharging it to the grid from storage. Under these existing rate schemes, the economically efficient and resilient behavior will keep distributed batteries charged for blackout events as opposed to charging and discharging batteries daily. For these reasons, we make the conservative modeling assumption that distributed storage assets do not participate in grid operations throughout the study horizon. Beyond PR100, future analysis that explores alternative policies and virtual power plant models that support grid interactive distributed storage operations could clarify the value of such options.

8.2.6 Capacity Expansion Technologies

Capacity expansion technologies are those that the Engage modeling tool has the option to build alongside the existing generation to meet electricity demand. For each technology, we specified technological characteristics and costs for each year through 2050. We based these yearly characteristics and parameters on projected technological and manufacturing improvements. Some technologies explored in PR100 either require long permitting periods or are not market ready, so we also specified the first model run year in which Engage has the option to build each technology. Table 29 lists the capacity expansion technology options we explored in PR100.

Table 29. Technologies Considered in Capacity Expansion Modeling

Technology	First Run Year Available	Description
Utility-scale PV	2025	Fixed-tilt PV systems described in 4.1.2 (page 65)
Land-based wind	2025	Typhoon-rated, land-based wind turbines described in 4.2 (page 101)
Utility-scale battery storage	2025	Lithium-ion batteries
Biofuel	2025	Internal combustion engine generators powered by 100% biofuel
Offshore wind	2035	Typhoon-rated offshore wind turbines described by Duffy et al. (2022). Both ground-mounted and floating systems were considered.
OTEC	2035	In modeling, the project team is currently considering only the shelf off the coast of the

Technology	First Run Year Available	Description
		Municipality of Yabucoa. Initially, the team is estimating 400 MWe of nominal OTEC capacity, which we model conservatively to produce a maximum of 440 MW. (NREL-estimated maximum production figures are closer to 520 MW.)
Hydrogen electrolysis, compressed hydrogen storage, and hydrogen combustion turbine	2035	The model represents hydrogen as a potential long-term storage option, cost-optimally sizing the electrolyzer, storage, and combustion turbine components independently.
Hydroelectric power	2025	The largest catchment areas, reservoirs, and turbine generator dams with highest technical potential—i.e., the most potentially cost-effective hydroelectric systems—were modeled but found not to be cost-effective for refurbishment or capacity expansion of either the generators or reservoir storage from a pure cost and generation perspective.

8.2.6.1 Cost and Operating Characteristics

The underlying capital and operating costs and operating characteristics of each of the capacity expansion technology options are described next. These costs were scaled to align with Puerto Rico costs and used as inputs along with financing costs, taxes, depreciation, and incentives to calculate levelized annual costs ($/kWh). Figure 133 and Figure 134 show the range of levelized costs for each technology in 2025 and 2035. Known operating costs for existing plants provided by LUMA were used to calculate levelized cost of energy (LCOE) for the existing plants. Table 30 provides an overview of the underlying capital and operational costs by capacity expansion technology in the first year the model is permitted to build the technology.

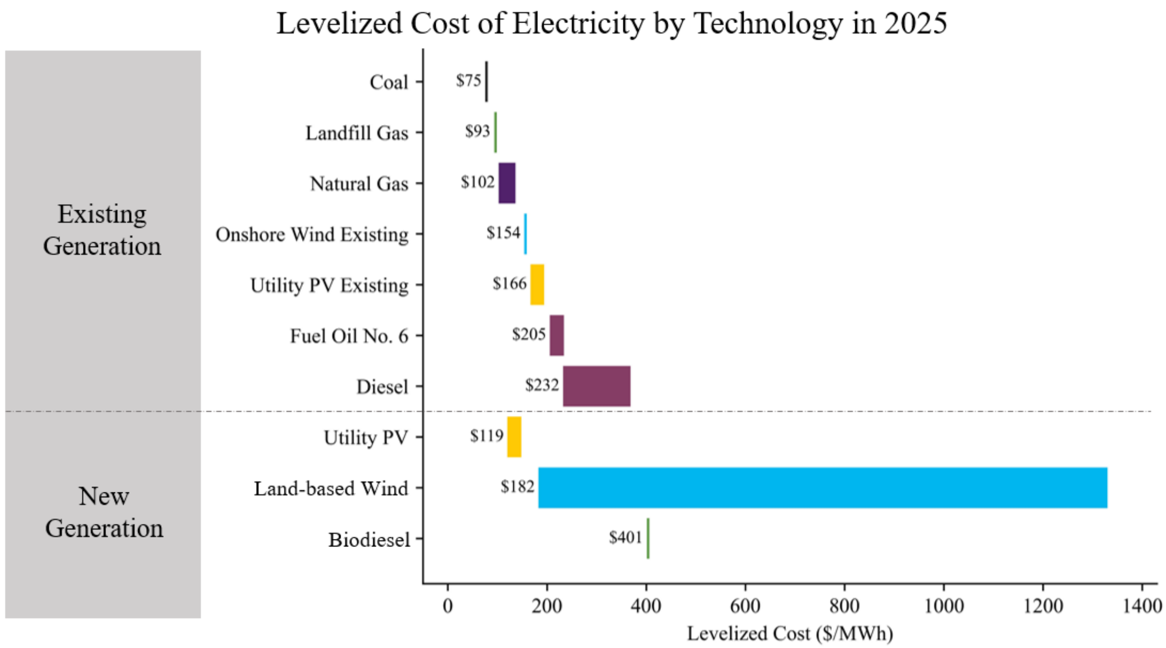


Figure 133. Levelized cost of eletricity by technology in 2025 (costs in 2021 real dollars)

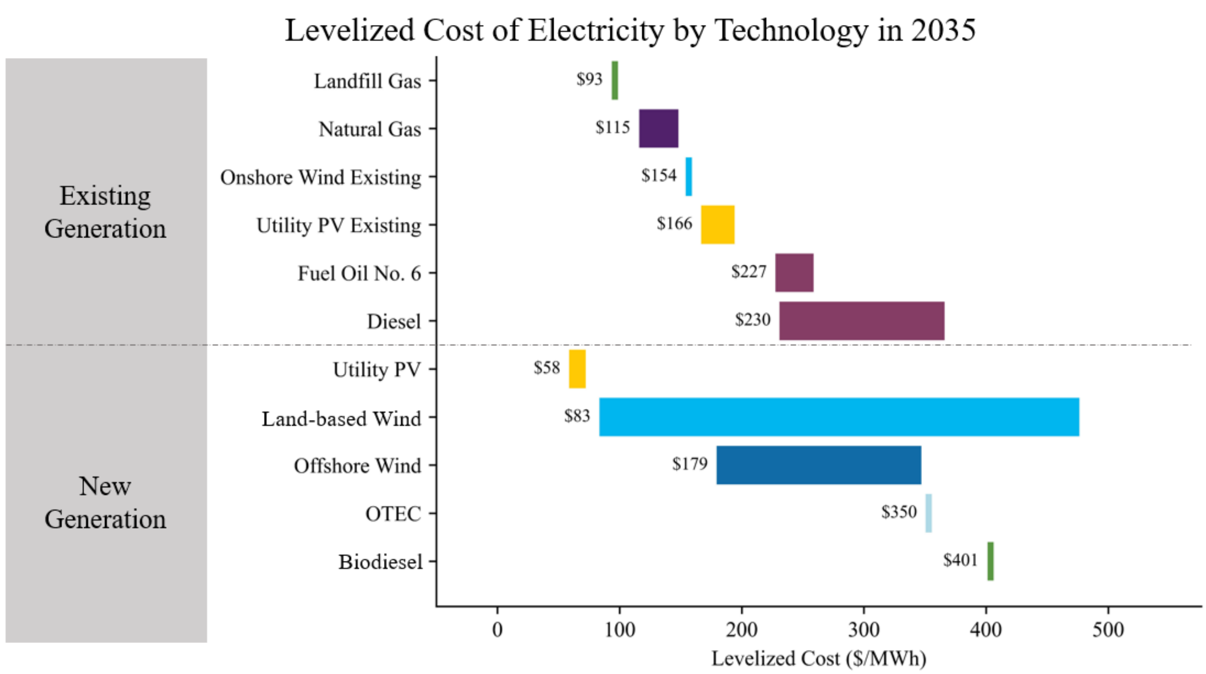


Figure 134. Levelized cost of eletricity by technology in 2035 (costs in 2021 real dollars)

Table 30. Capital Cost Assumptions by Technology in First Potential Build Year

All costs are in 2021 real USD. Costs for PV and wind technologies were calculated using the weighted average of the cost and capacity for potential plants in the capacity expansion model across the More and Less land scenarios.

Technology (first operational year)	Utility-Scale PV (2025)	Land-Based Wind (2025)	Utility-Scale Battery (2025)	Biofuel (2025)	Offshore Wind (2035)	OTEC (2035)
Power Capacity Capital + Transmission Interconnect Cost[a] ($/kW)	1,657	3,772	672.90	4,540	4,690	19,270
Storage Capacity Capital Cost ($/kWh)	—	—	644.10	—	—	
Fixed Annual Operation and Maintenance (O&M) Cost ($/kW-yr)	29.09	98.51	53.05–198.00		70.83	144.60
Variable Non-fuel O&M Cost ($/MWh)	—	—	—	5.96	—	--
Fuel Cost ($/MMBtu)	—	—	—	5.6	—	--

[a] Transmission interconnect costs are only applicable to Utility-Scale PV, Land-Based Wind, Offshore Wind, and OTEC.

8.2.6.1.1 Utility-Scale Photovoltaics, Land-Based Wind, and Offshore Wind

We describe the utility-scale PV, land-based wind, and offshore wind plants modeled using the Engage modeling tool in the renewable resource section (Section 4, page 59). To incorporate the PV potential into the model, we aggregated the PV resource, capital, and operating costs assumptions to the 115-kV or 230-kV transmission substation level. We then used a natural breaks algorithm (based on LCOE and LCOT) to group the aggregated PV resource points that connected to each substation. We derived costs for the grouped plants by calculating the capacity-weighted average of all plants and spurline costs within each group. We did not aggregate the land-based wind or offshore wind resource profiles because the greater capacities and land areas associated with each data point generated by the resource potential studies mitigated the need to aggregate.

8.2.6.1.2 Utility-Scale Battery Storage

We based the battery storage technologies represented in the capacity expansion model on the Annual Technology Baseline lithium-ion batteries. We modeled 2-, 4-, 6-, 8-, and 10-hr duration batteries with 85% round-trip efficiencies.

8.2.6.1.3 Biodiesel

The biodiesel technology option is an internal combustion engine generator powered by 100% biofuel. We sourced the operational and cost data for the internal combustion engine generator from EIA's 2022 Annual Technology Outlook (EIA 2022). We assumed biodiesel generators to be the most cost-effective, flexibly dispatchable, renewable generation on the market. As new renewable technologies come on the market that are less expensive and can be dispatched flexibly, these technologies should replace this biodiesel placeholder. We assumed the biofuel generator technologies are fully mature and see no capital or operational cost declines in the future.

8.2.6.1.4 Ocean Thermal Energy Conversion

OTEC is an emerging technology being tested in ocean areas with large differentials between surface temperature and temperature at depth. OTEC was studied as a potential renewable energy generation source in Puerto Rico because of the narrow continental shelf and steep continental slope ensuring that depths in excess of 1,000 m are found within 5 km of the shore roughly off the Puerto Rico's southeastern coast, just off point Tuna and near the town of Yabucoa. These oceanographic conditions are considered excellent for ocean thermal energy conversion (Atwood et al. 1976).

Limited cost data exist on the currently operating plants around the globe, and cost projections for plants at bulk power system scales are very limited in diversity of sources and number. The capital costs used in the Engage modeling tool were sourced from a 2012 Lockheed Martin report (Martel et al. 2012), adjusted for Puerto Rico and a risk premium because OTEC is not yet a commercially available technology and there are no demonstration projects at the scales under consideration in the study.

8.2.6.1.5 Hydrogen Electrolysis, Storage, and Generation

We chose electrolytic hydrogen production, compressed hydrogen storage, and hydrogen combustion turbines for electricity generation as long-term storage options in our analysis. The model independently sizes each element of the hydrogen technologies separately to most cost-effectively match hydrogen generation capacity and hydrogen-fueled electric generation capacity to the needs of the system, and conserving funds on the components projected to be relatively capital-intensive and better utilized at high capacity factors, such as the electrolyzer. The model does not represent opportunities to convert existing turbines from fossil fuels to hydrogen or dual-fuel opportunities. Nor does the model represent importing hydrogen to fuel turbines which could better position hydrogen to compete with technologies like biodiesel to meet renewable firm capacity needs in Puerto Rico.

8.2.6.1.6 Hydroelectric Power

We modeled hydroelectric power using existing reservoir and generator capacities and flow projection data from Oak Ridge National Laboratory (publication forthcoming) describing potential opportunities to expand the hydropower system and power generation capabilities. We performed several exploratory analyses to examine the economic viability of expanding the storage capacity of the reservoir system (through dredging) and turbine generators through refurbishment and determined that it was not economically viable when competed against the other technologies from a purely cost of generation and storage perspective, i.e., not accounting for value of possible black start capabilities or alternative uses for reservoir capacity such as irrigation and fresh water supply. The need for periodic dredging of reservoirs to maintain their capacities appeared to be one significant contributor to expected cost infeasibility due to high sedimentation rates of the reservoirs and many previously existing reservoirs that have become completely sedimented. Another factor that influenced the cost feasibility of hydroelectric power was the priority alternative uses of water such as irrigation and fresh water consumption resulting in large, prioritized water draws from the reservoirs. Because of this lack of economic viability and the very limited capacity and dispatchability of the existing system, we decided to remove the options to expand the hydroelectric system from the final sets of model runs to reduce computational complexity and include other constraints and considerations. Ultimately, the capacity expansion model represents 10 MW of existing hydropower capacity throughout the PR100 horizon.

8.2.6.1.7 Puerto Rico Capital and Fixed Operation and Maintenance Cost Scale Factors

To account for the higher costs for energy infrastructure seen in Puerto Rico, we applied scale factors to the capital, transmission interconnect, and fixed operation and maintenance (O&M) costs for all capacity expansion technology options. We derived these Puerto Rico–specific scale factors from the original and updated Tranche 1 costs shared by PREB. Assuming the updated Tranche 1 costs retain the same fundamental purchase and operating agreement terms and conditions as the originally released Tranche 1 contracts, the capital costs associated with the new Tranche 1 prices are 2.25 times higher than capital cost values for fixed-tilt PV plants from the renewable resource task. Initial Tranche 1 contracts indicated that the capital costs associated with the original Tranche 1 projects were 1.39 times higher than the capital cost values for PV plants. Because these costs increase dramatically over a short time frame, we assumed this increase was because of external factors that will decline over time. To represent this cost decline assumption, we applied scale factors that decreased linearly from 2.25 in 2025 to 1.39 in 2035 to all capital and operating costs for the capacity expansion technology option. Table 30 lists the scaled costs for each technology in the first year we allow the capacity expansion model to build the technology.

8.2.6.1.8 Power Purchase and Operating Agreement Cost Calculations

As mentioned in the methodology section (Section 8.1, page 211), we performed the capacity expansion modeling from the perspective of the grid operator. Thus, to accurately account for the costs incurred by the grid operator, the model was configured to represent potential contractual agreements between the grid operator and individual power producers. Such contractual agreements are called power purchase and operating agreements (PPOAs) in Puerto Rico. PPOAs define how much the utility will pay an independent power producer (IPP) for each MWh of electricity it produces. PPOA prices factor in not only the capital and operating costs associated with a generation or storage technology but also other costs and benefits to the IPP such as taxes, incentive programs, technology degradation over time, and contractual payment obligations (Table 31). Our modeling approach assumed the utility will procure all new generation and storage technologies through PPOA contracts, except for with the hydrogen technologies.

Table 31. Assumptions Included in PPOA Prices

Assumption	Data Source
ITC incentives	Inflation Reduction Act of 2022
Take or Pay Contract with 80 hours of allowable curtailment	Redacted Tranche 1 standalone solar PPOAs from 2022
Inflation rate	Proprietary data from FOMB
Depreciation	MACRS for the variable renewable energy and battery technologies

Using the terms defined in the Tranche 1 PPOA contracts, we created a tool to translate the capital and operational costs for the capacity expansion technologies described in this section into PPOA contract $/MWh prices. It demonstrates the costs per megawatt-hour of electricity, or PPOA prices, for each technology considered for capacity expansion.

8.3 Energy Justice Implications

This integrated capacity investment analysis demonstrates energy justice implications across the modeling methodology, inputs and assumptions, and key findings.

First, the goal of the integrated capacity investment analysis is to minimize costs of the bulk power system while ensuring the system has adequate generation and storage capacity to meet demand as well as sufficient reserve energy and capacity to meet demand during contingency scenarios. A contingency scenario might involve an unplanned generator outage or a period with low solar resources. Energy system cost and reliability are basic distributive energy justice concerns, and this analysis looks to develop a bulk system that is both cost-effective and reliable.

Second, we incorporated procedural justice into this analysis by soliciting and incorporating stakeholder feedback into the integrated capacity investment modeling inputs and assumptions. The following capacity investment inputs and assumptions were informed by stakeholder feedback:

- The two land use scenario variations (More and Less land) were defined and updated based on stakeholder feedback regarding which land categories should be excluded from the two variants.
- The capacity expansion technologies considered in this study were informed by stakeholder input. Notably, fixed-tilt PV systems were modeled instead of single-axis tracking systems to represent the PV systems being installed in Puerto Rico and a more high-wind resilient technology type.
- Capacity expansion technology costs were informed by data provided by stakeholders on the most recent renewable energy project costs for Puerto Rico.
- Existing system operation and maintenance costs, fuel costs, and operating characteristics were informed by data sets provided by stakeholders.
- The RPS configuration in the model was updated to consider all behind-the-meter renewable generation as contributing toward the RPS goals in each target year.

We also received some energy justice-related feedback that we were unable to incorporate into our modeling inputs and assumptions due to scope and model formulation limitations. The following inputs should be considered as caveats to this work and warrant follow-on analysis:

- The costs that we developed for renewable energy technologies include location-specific resource (solar or wind) availability, interconnection costs, and economies of scale costs, but do not account for the varying cost of land across Puerto Rico.
- This capacity expansion analysis did not assess the resilience trade-offs between a fully distributed grid and a grid with utility-scale generation.
- Best practices for installing renewable generation that does not increase flood risks.

Beyond the inputs and assumptions considerations, the key findings from the integrated capacity analysis are also associated with several energy justice implications:

- Emissions reductions achieved through the RPS compliance.
- This analysis did not examine the cost differences that would arise from distributing utility-scale generation capacity more evenly across Puerto Rico in the More Land scenarios.
- Less Land scenarios indicate that utility-scale generation would become more dispersed than in the More Land scenarios.

Transformational energy justice impacts are possible for this analysis. The modeling tools used in this analysis, Engage and PRAS, are both open-source models that both the regulatory agency and the utilities can access and use to conduct further analysis.

8.4 Results

The key results of the analysis performed in the capacity expansion and resource adequacy modeling include generation and storage capacities built across the scenarios and modeling years. Capacity expansion and resource adequacy model results are combined in this section to present the integrated capacity needs in each scenario. The integrated capacity results for each scenario show the different future build-outs needed to meet the resource adequacy and RPS requirements, considering the different projected demands, DER adoption levels, and land use constraints across scenarios.

In addition to producing generation and storage capacity results, the integrated capacity analysis, outputs spatial build-out and cost results. For the utility-scale renewable generation technologies—land-based wind and PV—the capacity expansion results include the model-selected geographic distribution of land-based wind and PV across Puerto Rico. Additionally, the integrated capacity analysis produces annual levelized costs associated with the procurement of power from new generation and storage capacity as well as the fixed costs associated with operating the existing generation fleet. These costs are combined with the cost results from other areas of this PR100 analysis (e.g., the DER adoption and production cost modeling analysis) and used as inputs to the economic impact analysis (Section 12.1.3, page 425).

The capacity expansion modeling includes simplified representations of system operations on which basis the build-out and size the cost-optimal generation and storage technologies for each year and scenario are determined. Subsequently, a production cost modeling analysis (Section 9) performed a more detailed operational scheduling and power-flow analysis to assess the more realistic operation of Puerto Rico's grid.

8.4.1 Existing System Resource Adequacy

By evaluating the resource adequacy of the existing Puerto Rico power system, we verify the PR100 model representation of the existing grid reliability performance. The principal point of comparison for resource adequacy is the recent LUMA resource adequacy report (LUMA 2022). The report outlines the capacity availability for many of the existing generation resources in terms of maximum generator production capabilities and forced outage rates. With consistent generator parameters, the PR100 project team was able to replicate the resource adequacy metrics presented in the report using the PRAS model. Table 32 summarizes the resource adequacy results for the PR100 existing system with and without accounting for planned generation outages. Table 32 also shows the ideal (always available) capacity that must be added to the system to achieve an overall loss of load expectation of 2.4 event-hr/yr.

Table 32. RA Results for the Existing Puerto Rico Power System With and Without Accounting for Planned Generation Outages

Scenario	FY23 System Without Planned Outages	FY23 System with Planned Outages
Overall expected unserved energy (MWh/8,760 hr)	3,140±40	95,800±300
Overall loss of load expectation (event-hr/8,760 hr)	23.2±0.2	515±1
Ideal capacity (MW)	350	850

The existing system EUE results are also shown in Figure 135. The heat map indicates that outages are especially likely during evening hours in October. Overall, the resource adequacy results confirm that Puerto Rico's existing electric grid is in urgent need of upgrades to elevate reliability to industry-accepted levels of performance.

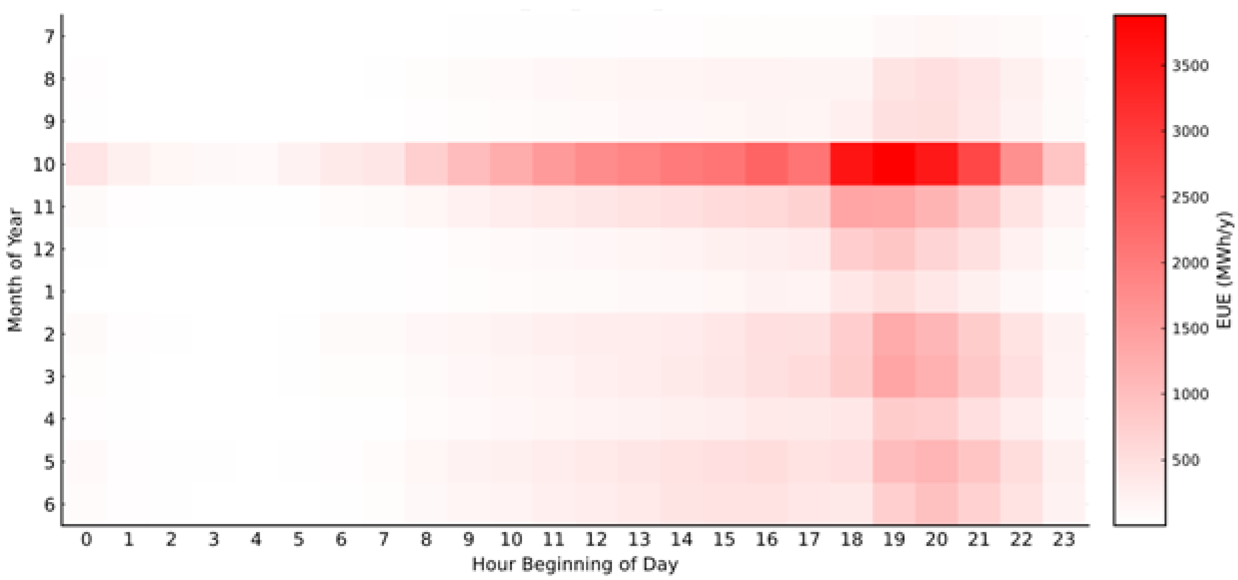


Figure 135. Average EUE by hour of the day and month of the year in megawatt-hours per year for the existing power system

8.4.2 Capacity Build-Out Across Years

The integrated capacity analysis produced least-cost generation portfolio solutions across the seven modeled years (2025, 2028, 2030, 2035, 2040, 2045, 2050) for each scenario. Because the model was constrained to meet the RPS targets of Act 17, these results represent the cost-optimal systems that meet RPS targets stipulated in the law. Figure 136 shows incremental additional production capacity for each year and scenario variation.

Key Finding: We see much larger jumps in utility-scale capacity procurements to meet the 2025 and 2050 RPS requirements than to meet the 2040 RPS requirement.

The RPS goals require Puerto Rico to achieve:

1. 40% renewable generation and system reliability in 2025, a large increase in renewable energy generation and storage is needed;

2. 60% renewable generation in 2040, an increase in renewable energy generation of 20% of total annual electricity consumption from the 40% in 2025 in 15 years; and

3. 100% renewable generation in 2050, an increase in renewable energy generation of 40% of total annual electricity consumption from 60% in 2040 in 10 years.

The 40% RPS requirement and recovery of system reliability in 2025 and the 100% RPS requirement in 2050 require relatively large increases in utility-scale renewable generation over similar or shorter time periods as compared to the 60% RPS requirement in 2040.

For 2025, the models build and recommend enough capacity to both meet the 40% RPS and increase system reliability from a low current state of reliability. A relatively large quantity of renewable generation and storage is required to achieve these somewhat overlapping objectives.

Between 2040 and 2050, a number of factors contribute to the need for an even relatively larger build-out of renewable generation and storage across scenarios:

3. The 100% RPS requirement of 2050 represents another 40% increase in the RPS requirement for renewable generation, from 60% in 2040 to 100% in 2050. One factor is that, in the Stress load scenario variations, this is a 40% larger load than in 2025, but this doesn't explain the larger amount of capacity built to meet the 2050 requirement for recovery reliability and meet the 40% 2025 RPS requirement across all scenarios.
4. Another factor is that by 2050 all the legacy fossil generation on the system is retired, reducing the amount of dispatchable generation on the system. Renewable generation must be deployed to make up for this loss of capacity.
5. Third, in general, each incremental increase in the proportion of electricity generated by variable renewables actually requires more renewable generation capacity than prior increases because, as more variable renewable generation is added to the system, the incremental renewable capacity produces at lower capacity factors during times when the renewable resource is less available and lowers the capacity factors of the variable renewable generation already on the system. This results in lower overall capacity factors for the variable renewable generation on the system and more curtailment of this generation during some times of high resource availability. Additionally, during these intervening years, distributed PV, which contributes to the RPS is being deployed.
6. Finally, although the deployment of storage in these years reduces curtailment and increases utilization of the generation from variable renewable generation, use of storage, because of losses associated with the round-trip efficiency of storage, requires more energy production than direct dispatch from renewable generation to load.

These factors combine to require much more variable renewable generation capacity to meet the last 40% of the RPS requirement than the first 40%.

The 2040 60% RPS requirement, on the other hand, is a smaller (20%) incremental increase in proportion of load that must be met by renewable generation than the 2025 and 2050 40% incremental increases. Furthermore, there are a few forces in the years between 2025 and 2040 that drive build-out. The planned storage procurements in the tranches and the 2028 retirement of coal show storage procurement by 2028. In parallel, through 2032, planned retirements from the fossil fleet result in more storage being added in 2030 and land-based wind and/or storage being built across scenarios by 2035. These build-outs in intervening years mean that less additional capacity is needed between 2035 and 2040 to meet the 60% RPS requirement in 2040. This is true even if we add all the capacity the models build and recommend from 2028 through 2040 in each scenario.

Figure 136. New-build capacity across all scenarios by year

8.4.2.1 2025: Achieving System Reliability and 40% Renewable Generation

Key Finding: To meet the near-term 40% renewable portfolio standard (RPS) and system reliability needs, multiple gigawatts of renewable generation and storage capacity are needed by 2025.

Key Finding: Planned tranches are insufficient to reach 40% renewable energy generation by 2025, assuming utility-scale PV or similar.

As shown in Figure 137, model results indicate multiple gigawatts of utility-scale renewable generation needed—in addition to the hundreds of megawatts of projected distributed PV—to bring the grid to an acceptable level of performance and meet the near-term 40% RPS (Act 17) goals by 2025. This large amount of capacity build-out in 2025 occurs across all scenarios and surpasses the tranche procurement schedule outlined in the PREB resolution and order. Even in Scenario 3, with the fastest and greatest levels of distributed PV adoption, a large amount of utility-scale PV is still required in 2025. Deployment of renewables at a rate to achieve the 40% RPS goal would require a rapid rate of procurement of over 100 MW per month through 2025 from a level of minimal utility-scale build-out in recent years. This rate of deployment would be challenging to achieve. The total of the tranche procurements of generation (currently planned through 2026) generally aligns in scale with our scenario results that achieve a 40% renewable RPS and retirement of coal, however, the modeling indicates a need for more storage power and energy capacity than planned in the tranches.

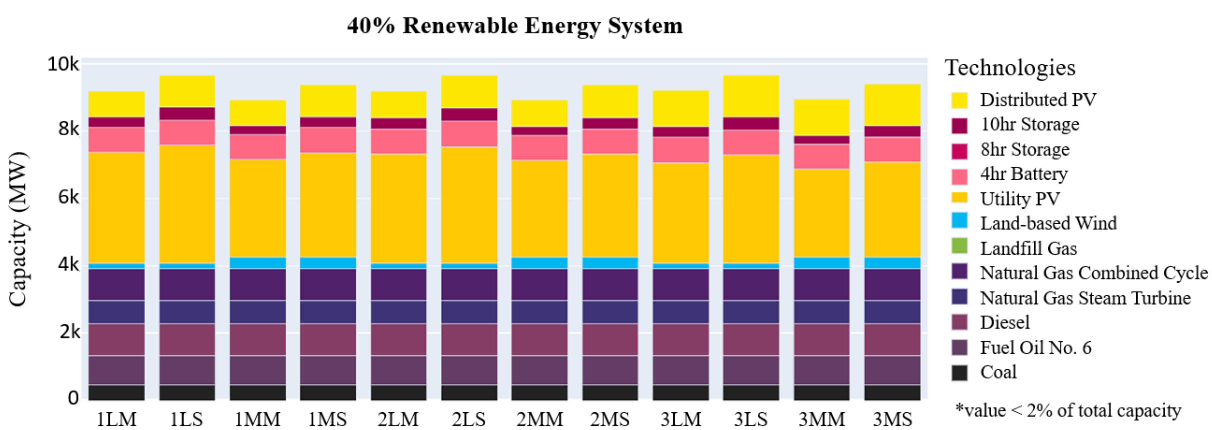


Figure 137. 2025 system capacities that achieve the 40% RPS and meet immediate system RA needs

Across scenarios, 2,620–3,490 MW of solar, 172–343 MW of wind, and 5,600–6,930 MWh of storage are added to the existing system by 2025. The 1LS scenario requires the largest quantity of combined utility-scale generation capacity and has the smallest DER capacity adoption, while the 3MM scenario requires the smallest combined utility-scale generation procurement but has the largest DER capacity adoption. Scenarios with more available land for utility-scale generation build more land-based wind as more land with cost-competitive wind technical potential was available to the model in these scenarios. Scenarios with More Land and Mid case load require the smallest additional storage build-out due to the additional resource diversity provided by the additional wind generation in these scenarios.

Two different requirements drive the rapid near-term build-out of utility-scale generation: (1) meeting industry-accepted RA performance and (2) meeting the 40% RPS by 2025. Currently, the existing Puerto Rico electric grid is unreliable and does not meet the industry-accepted resource adequacy performance (Section 1.1.2); however, the integrated capacity analysis in this study requires that there is enough installed capacity to maintain industry-accepted levels of reliability. Additionally, in 2022, Puerto Rico met much less than 40% of its electricity consumption from renewables, leaving a large gap to achieve its 40% RPS requirement.

To evaluate how each of these requirements contributed to the 2025 build-out, we explored a variation that relaxed the 40% RPS requirement of the 1LS scenario. This relaxation significantly changed the technologies and total capacity selected in the build-out relative to the 1LS results; however, the relaxed RPS total capital and operating costs results were within 1% of the 1LS results. This similar cost result suggests that the dramatic build-out of utility-scale generation is driven principally by the requirement to achieve system reliability rather than the requirement to meet the 40% RPS.

The reliability impacts of this near-term build-out are evident when comparing the 2025 expected unserved energy (EUE) levels shown in Figure 138 with the FY23 EUE levels shown in Table 32. In lieu of the 350−850 MW of ideal capacity needs indicated by the existing system resource adequacy analysis in Table 32, resource adequacy analysis of the 2025 build-outs show that acceptable levels of performance can be achieved by adding renewable energy and storage capacity. The near-term build-out of renewable energy and storage capacity can avoid multiple gigawatt-hours of EUE.

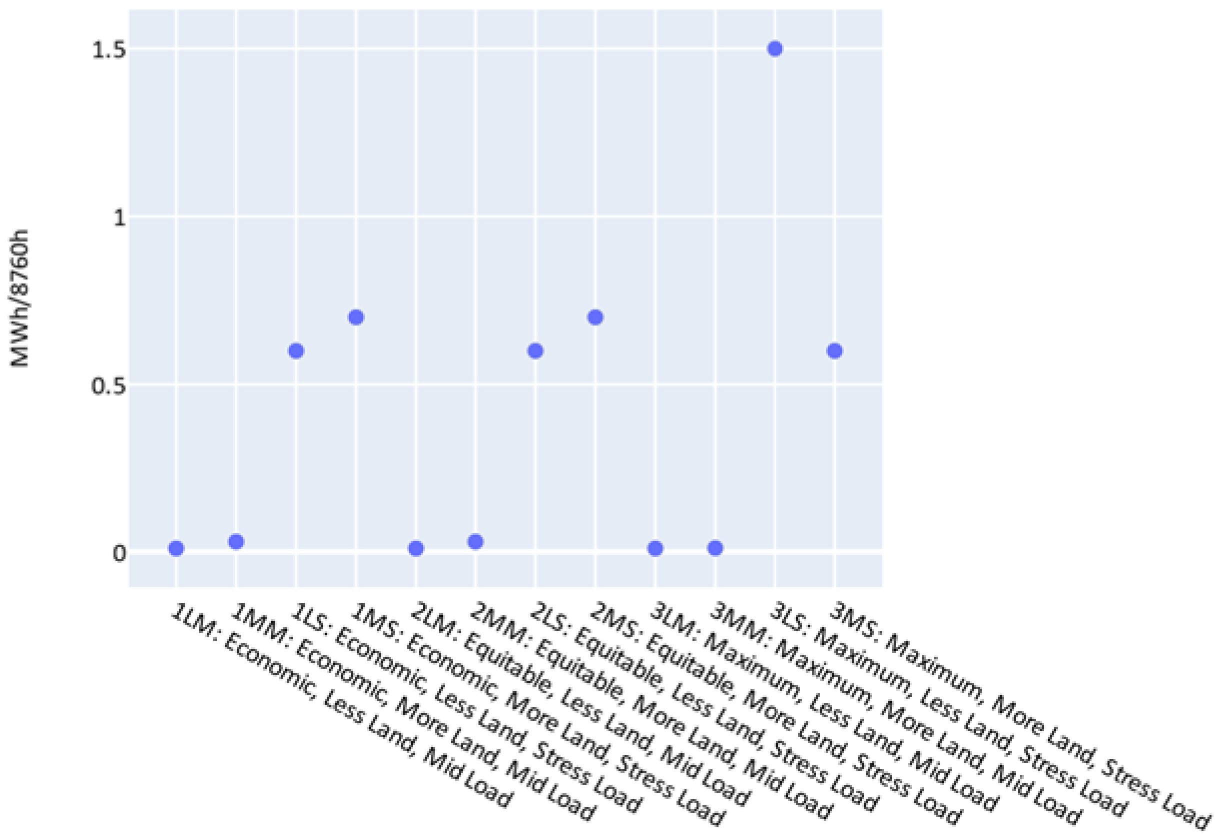


Figure 138. EUE for all scenario variations in 2025

The Engage capacity expansion tool does not simulate forecast errors, operating reserve requirements, and many physical generator and transmission constraints. As a result, the RA analysis indicates the need for additional resources beyond those identified by the capacity expansion model to create reliable systems. The PR100 project team conducted a sensitivity analysis to estimate the amount of additional capacity required to achieve near industry-accepted reliability levels (2.4 event-hr/yr). By incrementally adding 50 MW of ideal (always available) capacity to each expansion scenario-year in addition to the capacity expansion results from Engage and recalculating the reliability metrics, we estimated the additional ideal capacity requirements shown in Figure 139.

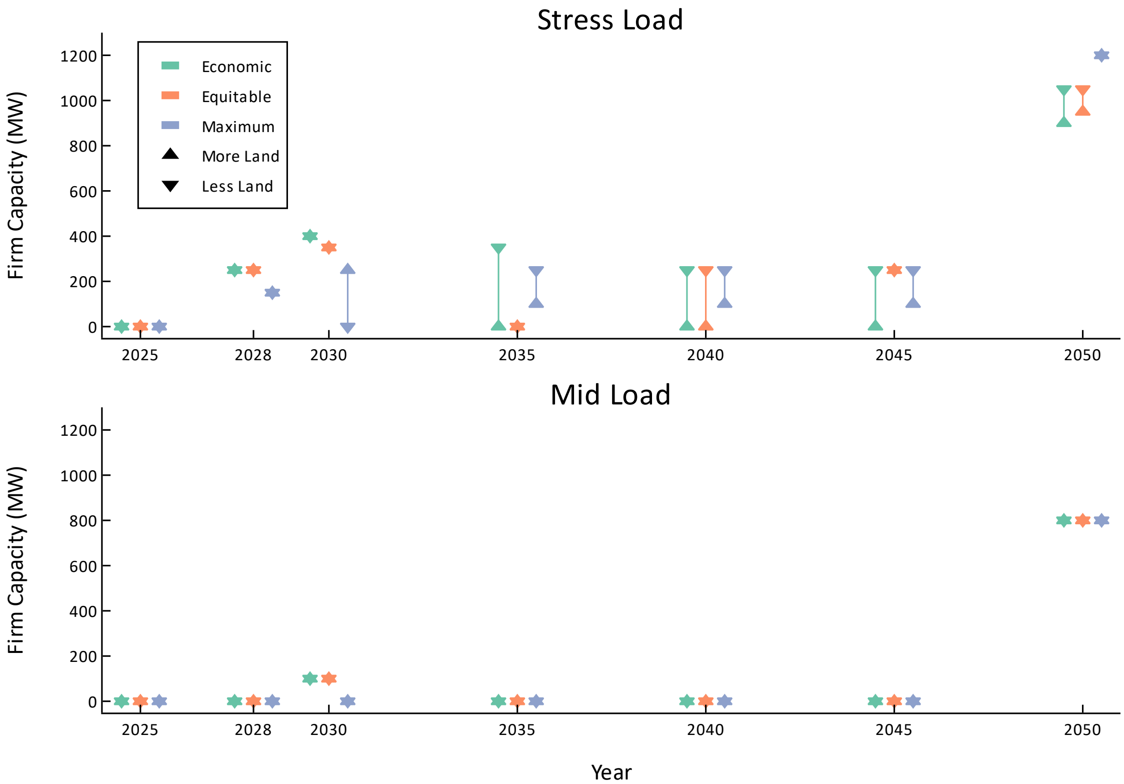


Figure 139. Additional ideal capacity (in excess of Engage modeling results) required to achieve industry-accepted reliability performance levels

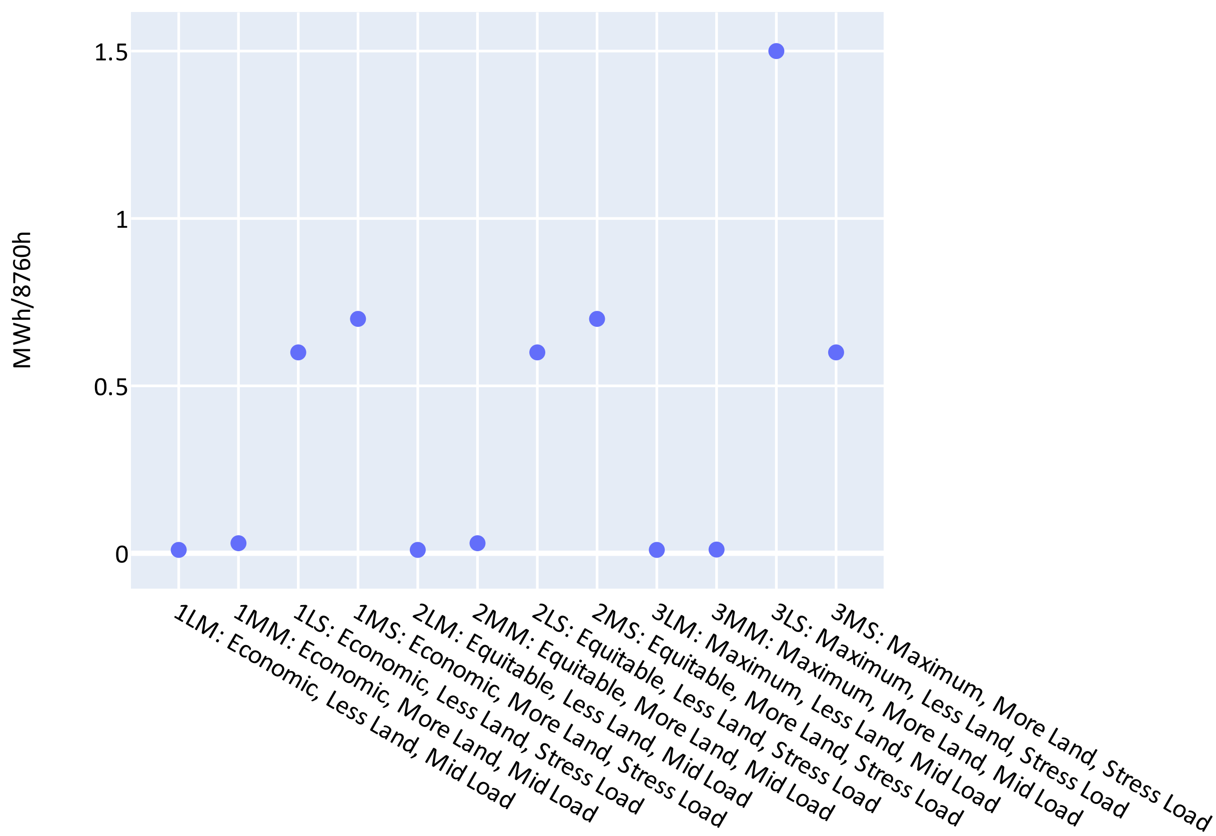


Figure 140. EUE for all scenario variations in 2025

The capacity expansion model enforces two separate requirements that could cause the extreme near-term build-out of utility-scale generation. First, the model suite requires that there is enough installed capacity to maintain industry-accepted levels of reliability. And second, the model enforces a 40% RPS in 2025. To evaluate which of these requirements caused the dramatic build-out, we explored a variation that relaxed the 40% RPS requirement of the 1LS scenario. This relaxation significantly changes the technologies and total capacity selected in the build-out relative to the 1LS results. However, the relaxed RPS total capital and operating costs results are remarkably similar (within 1%) to the 1LS results, suggesting that the dramatic build-out of utility-scale generation is driven principally by the requirement to maintain system reliability rather than the requirement to meet the 40% RPS.

8.4.2.2 2030–2045: Meeting Interim RPS Requirements and Maintaining a Reliable System

Looking across years 2028 through 2045, several other utility-scale generation results become apparent. For 2025, the model builds predominantly utility-scale PV and battery storage because these two technologies are the most cost-effective expansion options available in the Engage model to meet the system needs—distributed PV expansion upstream in the analysis and utility-scale 4-hr storage procurement via planned tranches are determined prior to Engage simulations). For 2028 and 2030, however, storage is the only utility-scale capacity added to the system, indicating that, with only additional storage, the existing generation and renewable generation built in 2025 is sufficient to meet demand after the coal plant is retired. In 2035, all scenarios aside from 3LM build some additional land-based wind capacity. This 2035 land-based wind build-out largely occurs because land-based wind becomes more economical in 2035, primarily because of an anticipated improvement in wind turbine technologies that deceases the $/MWh costs of electricity generated by the wind turbines. In 2040, the Economic and Equitable DER adoption scenarios with Stress loads, require additional utility-scale PV and/or land-based wind build-out to meet the increased demand and 2040 60% RPS goals. The Maximum DER adoption scenarios do not require additional utility-scale build-out to meet the demand and reach the 60% RPS goals. In 2045, only additional storage capacity is required to meet the demand across scenarios.

Because the model was only constrained to meet the RPS stipulated in Act 17 (in 2025, 2040, 2050), the model shows limited build-out in years where the RPS does not increase and existing generation has not retired. The limited nature of the build-out in these years is generally more pronounced in the Mid case load scenario variations with declining loads. As shown in Figure 143, though, even the Stress load scenario variations shows minimal relative build-out in 2040, highlighting the absence of build-out in the 2030s leading to the 2040 60% RPS requirement.

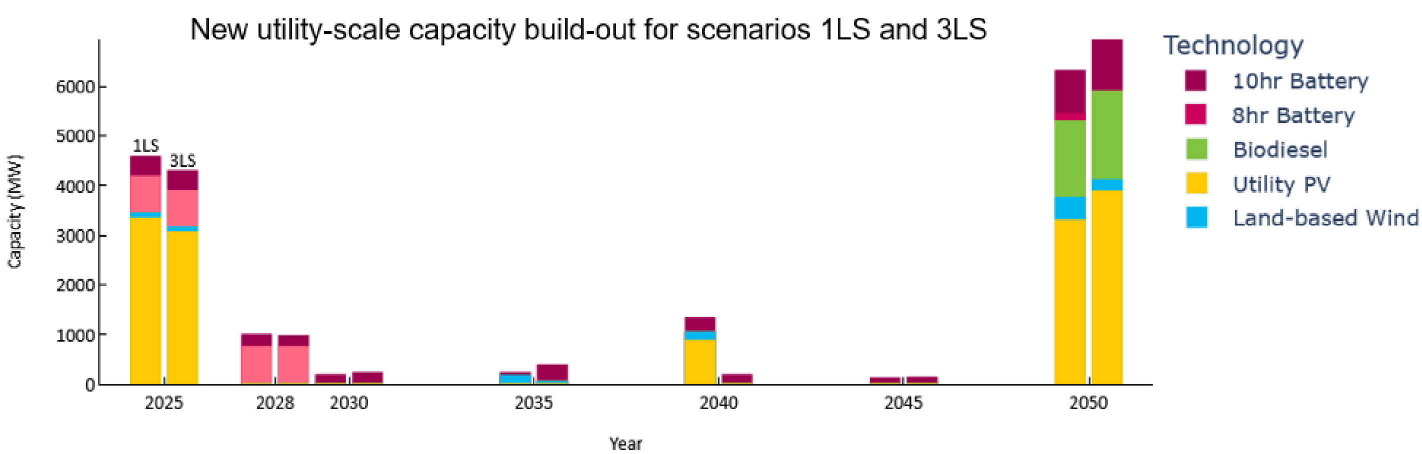


Figure 141. Year-by-year new utility-scale capacity build-out for scenarios 1LS and 3LS

8.4.2.3 2050: Achieving 100% Renewable Generation and Maintaining a Reliable System

Key Finding: Multiple gigawatts of renewable energy build-out are required between 2040 and 2050 to jump from achieving the 60% RPS to meeting the 100% RPS.

Key Finding: Significant flexible renewable energy capacity and generation are required to meet 100% RPS targets.

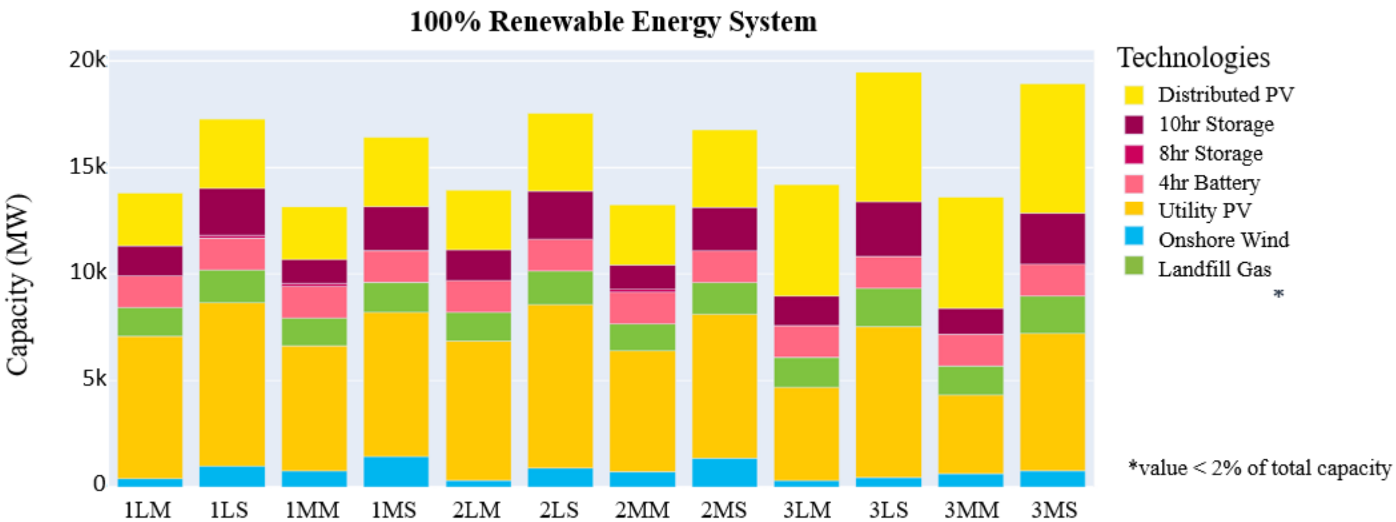


Figure 142. 2050 capacities: All scenarios

In 2050, multiple gigawatts of new-build generation are required to jump from the 60% RPS goal in 2040 to the 100% RPS goal in 2050. Thus, we see the largest jumps in capacity procurements in 2025 and 2050 to meet the RPS goals operative in those years. Because all fossil fuel generators that remained on the system were retired by 2050, the models see a need for additional "firm" capacity to meet the needs of the system. PR100 augments the Engage capacity expansion results with "firm" capacity detailed in Table 33 to create acceptably reliable future systems. PR100 adds 10-hr storage prior to 2050 and biodiesel in 2050 as representative "firm" capacity technologies; other technologies could emerge as viable alternatives. After the Engage model results are augmented with firm capacity additions, RA results indicate that projected future systems achieve industry-accepted levels of reliability performance. In other words, after the system is augmented with optimal expansion plans from Engage results and additional "firm" capacity, all PR100 modeled systems have loss of load expectations less than 0.3 event-hr/8760 hr.

8.4.3 Technology Types Selected

The capacity expansion process looks for the least-cost way to meet demand, and small variations in cost can drastically affect the resulting build capacities in the model. The decision to model typhoon-class wind turbines in Year 2 of this study increased the cost to build land-based wind plants, which in turn decreased the economic viability of wind across the scenarios—especially in earlier years. This increase in land-based wind costs led to an increased build-out of the more economic PV technologies along with significant battery storage build-out to serve load at night and compensate for the older, inflexible generation fleet. Significant amounts of wind were still built as the system pushed for a higher percentage of renewable generation, especially in the stressed load scenario variations.

Key Finding: Across the scenarios, we do not see deployment of OTEC, hydrogen production, hydrogen storage, or hydrogen-fueled generation.

Because of the relatively high costs of OTEC and hydrogen technologies compared to land-based wind, solar, and batteries, we do not see deployment of these technologies in the capacity expansion model.

8.4.4 Comparing Scenarios With Minimum and Maximum Utility-Scale Build-Outs

Across all scenarios, the scenario with the least amount of utility-scale generation in all years was 3MM—Maximum, More Land, Mid Load—whereas the scenario with the greatest amount of utility-scale capacity build-out was 1LS: Economic, Less Land, Stress load (Table 33). The 3MM scenario saw the least utility-scale build-out because this scenario had (1) less demand than the Stress load scenarios, (2) greater distributed PV build-out than the Equitable and Economic scenarios, and (3) access to more land with greater utility-scale PV and land-based wind generation capacity than the less land scenario. However, the 1LS Scenario saw the greatest utility-scale generation build-out because this scenario had (1) greater demand than the Mid Load scenarios, (2) less distributed PV build-out than the Equitable and Maximum scenarios, and (3) less access to land with higher utility-scale PV and land-based wind generation capacity than the More Land scenario.

Table 33. RA Results Across All Scenarios

Note	**3MM: Maximum, More Land, Mid case (2050 capacities)** Scenario with least utility-scale generation capacity	**1LS: Economic, Less Land, Stress (2050 capacities)** Scenario with the greatest utility-scale generation capacity
Utility-scale PV (MW)	3,690	7,670
Utility-scale battery (MWh)	18,000	28,900
Land-based wind (MW)	629	967
Biodiesel generator (MW)	1,370	1,540
Distributed PV (MW)	5,230	3,290

8.4.5 Impacts of More Land and Less Land Scenario Variations

The model results also highlight the effect of land limitations on wind build-out across scenarios, with the More Land scenarios resulting in more economic land-based wind build-out and therefore less PV build-out (see Figure 37 and Figure 38, page 86 for solar; Figure 61 and Figure 62, page 110 for wind). This implies that although the land use considerations do not have much of an effect on the build-out of PV, they do constrain the amount of economic wind available in Puerto Rico. Significant amounts of B100 biodiesel—a representative of many potential future dispatchable renewable technologies—was also built in 2050 across all scenarios to provide the flexible firm capacity needed for a system with significant variable resources. Other higher-cost technologies such as offshore wind, marine energy, and hydrogen storage were not chosen by the model in any scenario.

The geographic distribution of utility-scale PV and wind is also impacted by the land use scenario variations. The figures below show the spatial distribution of the maximum and minimum build-outs of utility-scale renewables achieved by 2050 in any expansion scenario and sensitivity for each of the six different regions in any of the scenario variations (Section 12.3.2.3, Figure 380, page 481). Each land use scenario has different candidate plants, so the figures show both land use scenarios to help examine how land use could affect the distribution of economic generation across Puerto Rico.

All scenarios show utility-scale PV build-out around the Commonwealth although the minimum build-out of the More Land scenarios has most of the capacity in the southern and western regions away from the largest load center in San Juan. In the scenarios that build significant amounts of land-based wind, there is also capacity spread out around Puerto Rico although there is still some concentration in the southwest away from San Juan.

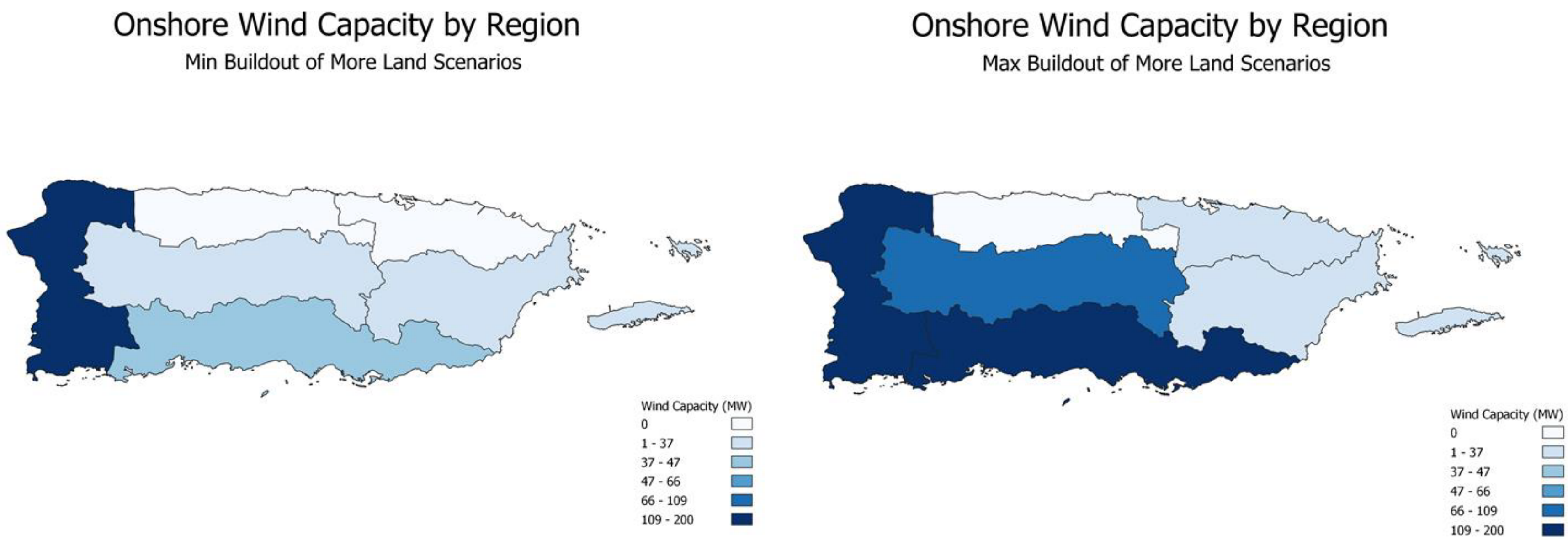


Figure 143. More Land maximum/minimum wind build-out

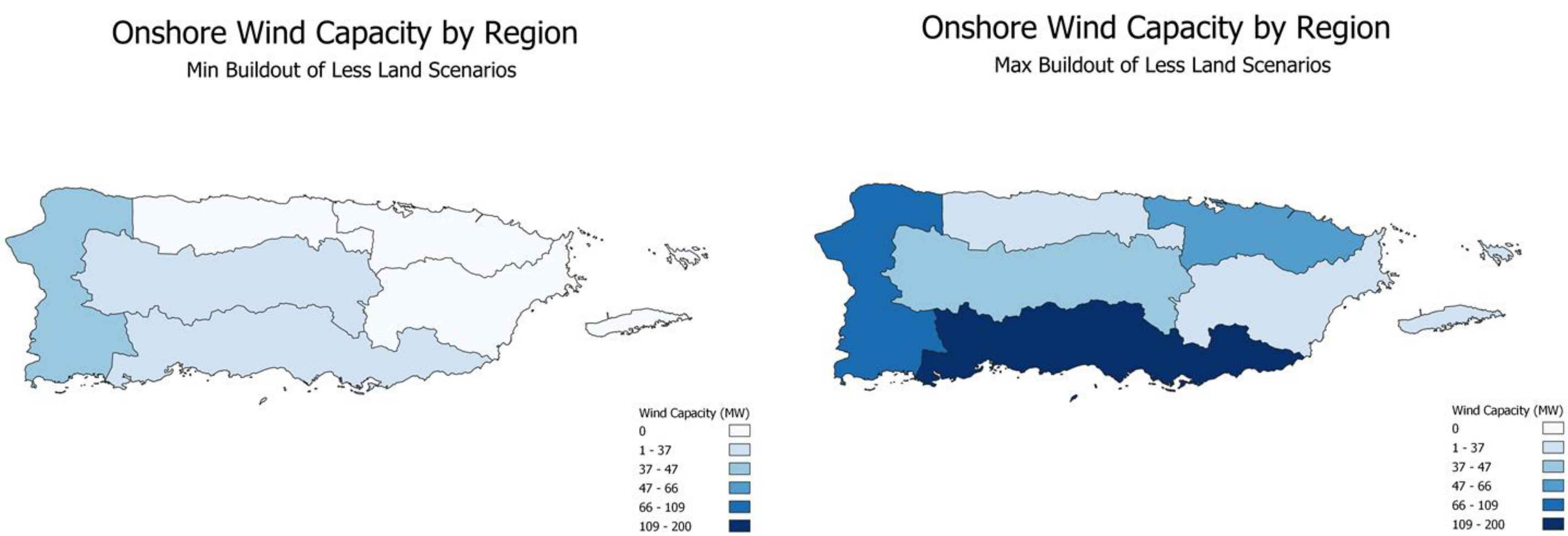


Figure 144. Less Land maximum/minimum PV build-out

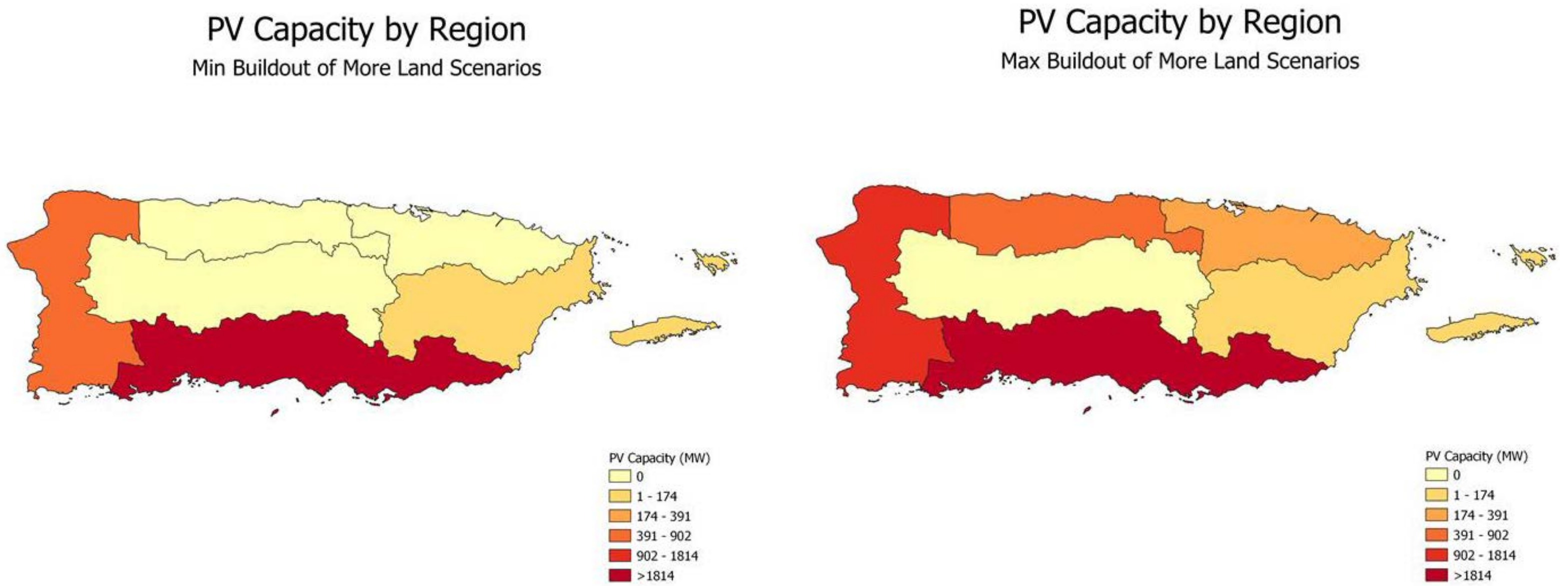


Figure 145. More Land maximum/minimum PV build-out

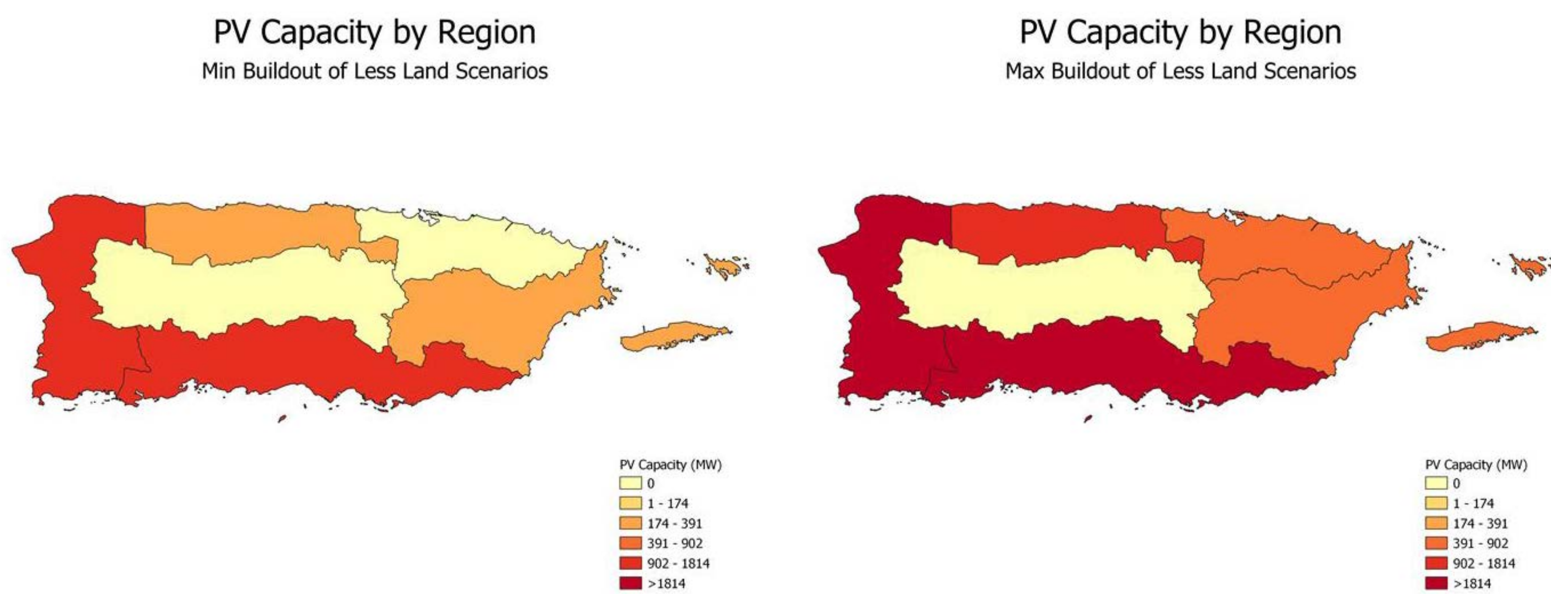


Figure 146. Less Land maximum/minimum wind build-out

8.5 Considerations

In this section, we discuss five considerations that are drawn from each of this section's key findings.

Our modeling shows that multiple gigawatts of utility-scale renewable generation and hundreds of megawatts of distributed PV will need to be built to bring the grid to an acceptable level of performance and meet near-term 40% RPS (Act 17) goals by 2025.

- The current Puerto Rico grid is not reliable and needs immediate additional capacity to meet an acceptable level of performance.
- The PR100 solutions represent systems that can operate reliably and meet the 2025 40% RPS goal.
- The capacities required in the currently defined tranches are insufficient to reach 40% renewable energy generation by 2025.

> **Consideration:** Accelerated approval process and immediate ramp-up of procurement and implementation of renewable generation capacity and storage capacity are needed to support achievement of the near-term RPS goals.

> **Consideration:** Defining future generation procurements (future tranches) in units of generation (MWh) rather than capacity (MW) would provide greater clarity in the procurement process.

Our modeling further shows that building multiple GWs of renewable energy capacity is required between 2045 and 2050 to jump from achieving the 60% RPS goal in 2040 to meeting the 100% RPS goal in 2050.

- All remaining fossil fuel generators will be retired by 2050, creating a need for additional dispatchable capacity.
- Rapid renewable energy deployment to meet the RPS also quickly improves Puerto Rico power system reliability.

> **Consideration:** A higher 2040 RPS requirement and additional interim requirements could support better planning, smoother transitions and lessen the risk of not achieving the 2050 goal. Pairing with noncompliance consequences would help ensure requirements are met.

Allowing all distributed PV production to count toward the RPS requires that less utility-scale generation be built across scenarios.

> **Consideration:** Further guidance and regulations on renewable energy certificates will be key to clarify the contribution of distributed renewable generation toward the RPS (Section 8.2.1).

Adding significant flexible renewable energy capacity and generation is required to meet 100% RPS targets, PR100 analysis indicates. However, OTEC, hydrogen production, hydrogen storage, or hydrogen-fueled generation are not deployed in any of the scenarios.

> **Consideration:** Relative levelized costs of different renewable generation technologies are key drivers for the results of the capacity expansion model. As renewable energy and storage technologies develop, the levelized costs of these and other nonmodeled technologies may change, driving different long-term build decisions. This study should be reevaluated with up-to-date technology costs over the years.

9 Bulk Power System Operational Scheduling

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Section Summary

This section focuses on understanding the future reliability of the bulk power system in Puerto Rico using production cost modeling (PCM) to simulate the least-cost-optimal scheduling of hourly electric generation to meet system demand and transmission constraints under each of the scenario variations throughout the study years. In Section 10.9, we discuss resilience under extreme weather conditions that cause system damage; this section focuses on operating the system under normal conditions that include reasonably likely peak demand periods, forecast errors, and resource variability. Analysis results indicate that the 38-kV transmission network will need upgrades to accommodate the projected scenario-variation system build-outs. Otherwise, results suggest that the projected future systems can be dispatched to meet energy demands in all periods, but operational scheduling practices will require significant evolution to manage forecast errors and integrate new resources.

Key Findings

- The projected system build-outs have sufficient generation, storage, and transmission resources to manage forecast errors and maintain reliable service under normal operating conditions.
- The lower-voltage (38-kV) transmission network components are insufficient to handle the projected system transitions.
- The relatively uniform resource quality in Puerto Rico supports widespread distribution of generation resources and alleviates the need to significantly enhance the high-voltage transmission network for normal operations.
- The lack of resource diversity in the projected systems makes managing forecast errors very challenging.
- Energy storage is a critical load-serving resource throughout the study scenarios and years.
- Renewable generation curtailment occurs throughout the study scenarios and years because the legacy generation fleet is inflexible and excess resources are built to ensure system reliability.
- Some generators are built economically but are rarely operated, indicating they provide value beyond just energy such as capacity and ancillary services.

Considerations

- Additional analysis is required to assess the feasibility of deployment timelines and interconnection design required to support reliable and secure future systems.
- 38-kV network upgrades are required to support projected build-outs.
- Additional analysis is required to understand the extent to which transmission topology reconfiguration, demand response, virtual power plants (VPPs), and careful system design to guide the placement of utility-scale generation and storage resources can avoid the need for some transmission expansions.
- Additional analysis of system security and extreme events may find conditions that require high-voltage transmission expansion.

- Better forecasting methods, updated operating reserves, and possibly additional flexible and dispatchable resources beyond PR100 projections may be required. This may be an area where demand response and VPPs could provide value.
- All storage technologies considered in PR100 predominately operate diurnally (with daily charge/discharge cycles). However, to sustain reliable system operations during extended cloudy periods, an extremely large amount of storage or other dispatchable renewable technology is required.
- Generation procurement processes that compensate for the value of grid services could help accelerate deployment.

9.1 Methodology

The principal goal of the bulk power system reliability, adequacy, and security analysis in PR100 is to evaluate the adequacy of projected future energy systems for Puerto Rico to produce and transport enough electrical energy to meet electrical demands at all times. To address this goal, we conducted PCM activities with the open-source Sienna modeling tools (NREL n.d.-b). Data sets representing current (2022) system conditions were developed and then augmented with Engage and Distributed Generation Market Demand Model (dGen) outputs to produce data sets for every expansion scenario and year.

9.1.1 Expansion Data Integration

Because the electricity demand projections (Section 5, page 117) and distributed solar and storage adoption (Section 7, page 186) results are delineated by year and municipality for even years throughout the study horizon, some interpretation is required to map the distributed solar and storage results to electrical buses (nodes) and expansion years. To map these biannual results to expansion years, we simply use the result for the most recent previous year. For example, in 2025 we use 2024 results, and in 2030 we use 2030 results. To map the distributed solar and storage adoption results between municipality and electrical buses, we disaggregate municipality results based on the proportion of electricity consumed at each bus relative to the total municipality electricity consumption during the peak load period condition defined by the LUMA load flow case. In all resource adequacy (RA) and PCM simulations, distributed generation resources are assumed to be uncontrollable by the grid operator. Therefore, no utility control/dispatch of distributed solar photovoltaics (PV), no utility management of distributed storage, and no utility managed demand flexibility is represented in PCM and RA simulations.

The Engage modeling tool that produces the system expansions has a reduced order transmission network representation. To create a more realistic estimation of interconnection points for new utility-scale resources identified by Engage, each new resource is connected to the closest transmission bus at or above 38.0 kV nominal voltage rating relative to its physical location. New resources are assumed to be available at the beginning of the expansion year. Otherwise, all operational costs and parameters are directly interpreted from Engage results.

9.1.2 Production Cost Modeling

Production cost models simulate the least-cost-optimal scheduling of electric generation to meet system demand and transmission constraints. In PR100, we use Sienna\Ops ("NREL-Sienna/Sienna" [2023] 2023) for production cost simulations. PCMs simulate a sequence of optimization problems where the results of each problem provide inputs to subsequent problems. This process enables the explicit representation of operator decision-making, where operators make decisions based on the available information when decisions are made. For example, every day the system operator gets a forecast of wind, solar, and load profiles for the next few days. At that point, the operator can plan a schedule based on the forecasted conditions. But, as actual conditions are realized and forecasts change, the system schedules and operations must be able to adjust accordingly. To simulate this process, Sienna\Ops relies on both forecasted wind and solar production profiles as well as simulated "actual" production profiles generated by the resource assessment discussed in Section 6. With the forecasted values, Sienna\Ops schedules the least-cost generator commitment and dispatch to meet system demands while considering generator and storage resource operation constraints, transmission constraints, and operating reserve requirements. The specific configurations are described in Section 9.2. Ultimately Sienna\Ops provides detailed results on simulated generator power production, reserve provision, and operating cost, along with active power flow through transmission elements, and any system failures to meet demand or reserve requirements.

9.2 Inputs and Assumptions

The PCM and RA models rely on a common Sienna data structure. To establish an initial system representation that reflects recent/current electric system conditions, we collected data from Puerto Rico's electric industry stakeholders LUMA, and PREPA. The principal data sources that inform the initial system are load flow cases provided by LUMA and a production cost model assembled by LUMA that will inform the next integrated resource planning process. These data sets established the transmission topology (location and connectivity) and parameters (impedance, flow limits, voltage, and outage rates), nodal load consumption pattern, and the type and operational parameters of existing generators including heat rate, operation and maintenance costs, outage rates, minimum/maximum production capabilities, minimum on/off times, and ramp rates.

To simulate the operation of expansion scenario-year systems, the PCM and RA models relied on the outputs of several upstream modeling and analysis activities. Specifically, forecasted and actual power production capabilities of expanded wind and solar documented in Section 4, page 59 are used to constrain renewable resource operations. Load profiles that include energy efficiency, electrification, and other electricity demand adjustments for each expansion scenario-year were created in the electric load analysis (Section 5, page 117). Distributed generation and storage adoption and siting was also established using dGen (Section 7, page 186). Finally, all utility-scale generation and storage expansions were established with the Engage modeling tool (Section 8, page 209). We note that the PCM models use the same fuel costs as Engage. Due to the limitations of sequential operational simulations like PCMs and data availability limitations, contractual agreements that influence power production are not represented in the PCM. For example, many existing renewable resources in Puerto Rico have contracts that allow up to 80 hours of curtailment, beyond which resources are paid for the power that they could have produced. This arrangement is not represented in the PCM. Instead, the only curtailment penalties represented are the opportunity costs associated with dispatching more expensive generation.

The Sienna\Ops PCM was configured to reflect the operations of the existing system for benchmarking and validation. As the system evolves in different expansion scenarios, the operations configurations require adjustments to accommodate new/different resources and phenomena. For PR100, we attempted to identify a stable PCM configuration that enabled acceptable operational results across most expansion scenario-years. Therefore, the selected operational configuration is probably not perfect for any particular scenario-year and further operational cost reductions may be possible with careful tuning. Across all expansion scenario-years, the PCM was simulated with a multiday storage scheduling stage, a day-ahead unit commitment stage, and a real-time dispatch stage. Each of the decision stages configures problems slightly differently to be consistent with the accuracy of the information to which they are exposed and the timescales that govern relevant power system operational decisions. The details of each of the three decision-making stages are shown in Figure 147 and described below.

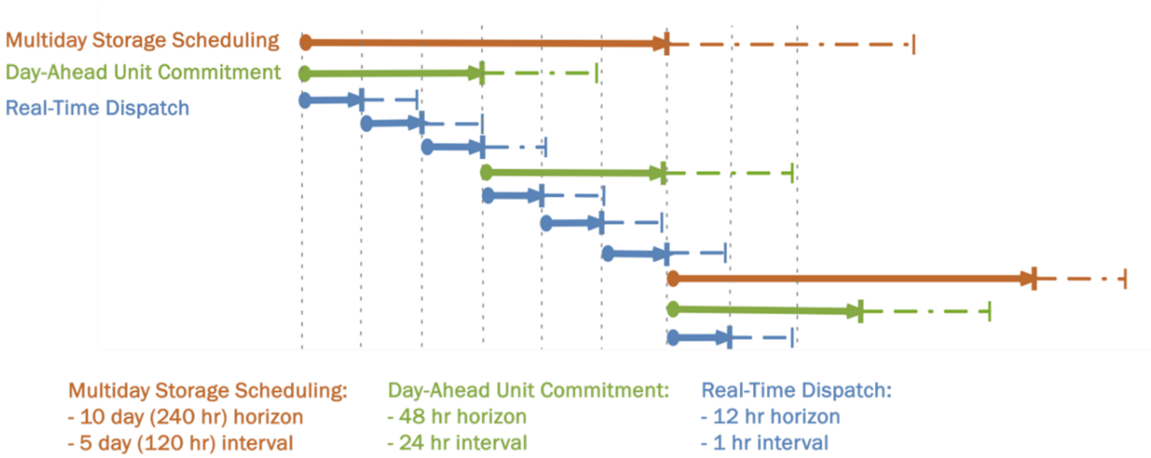

Figure 147. Illustration of PCM simulation configuration

- *Multiday storage scheduling* is used to estimate storage operations over several days to mitigate shortage conditions. The multiday storage scheduling stage simulates 240 hours (10 days) of operations every 120 hours (5 days). The problems represent simplified unit commitment, spinning and regulation reserves provision, and active power flows.
- *Day-ahead unit commitment* is used to schedule the on/off status of generation resources against day-ahead wind and solar production and demand forecasts. The day-ahead unit commitment stage simulates 48 hours of operations every 24 hours. The problems represent detailed unit commitment constraints, spinning and regulation reserves provision, and active power flows. In the day-ahead problems, the storage devices are given a state of charge (SOC) target in the 48th hour based on the results of the multiday storage scheduling problem.
- *Real-time dispatch* is used to adjust system operations from the schedules established by previous stages to operate under the realized conditions. The real-time dispatch problems simulate 12 hours of operations every hour. In the real-time problems, generator output (dispatch) is determined based on the unit commitment decisions that are fixed and cannot be changed and regulation reserve provision is co-optimized with energy balance. Storage devices are given a SOC target in the 12th hour based on the results of the day-ahead unit commitment problem.

Transmission is represented identically in all three problems using a linearized DC power flow model to represent lossless active power flow in the network. No transmission contingencies are represented in the PCM; additional contingency analysis is presented in Section 10 (page 267). Because of the uncertainty associated with the evolution of the lower-voltage network components, flow constraints are only enforced for elements with a nominal voltage at or above 115 kV.

In total, each annual PCM simulation used to simulate system operations for each expansion scenario-year solves 16,254 optimization problems.

9.2.1 PCM Benchmarking and Operational Tuning

To provide a basis for evaluating the operational changes required to achieve reliable system operations in each expansion scenario-year, we dedicated significant effort to benchmarking PR100 PCM simulations against historical operations. Several key differences exist between historical operation procedures and the methods used to simulate system operations that account for some differences between model results and historical operations. In particular, historical generator dispatches have often been decided by operator knowledge and risk avoiding decisions rather than an explicit cost-minimization problem as is represented in the PCM simulation. Therefore, PCM benchmarking activities have attempted to focus on improving the accuracy of the parameters that describe the technical capability of the system and individual components.

Many of the 84 (12 scenario variations × 7 solve years) expansion scenario-year systems represent significant deviations from the resource mix of the current and historical Puerto Rico grid. Likewise, the scheduling procedures used to operate the grid will need to adapt in order to maintain and improve system reliability. With the resource mixes projected across all the expansion scenario-years scheduling adjustments will be needed to address a variety of issues. PR100 scenarios project significantly different patterns of power injections/withdrawals as a result of evolutions in electric demand and distributed generation interconnections, increased variability and uncertainty from generation resources, and increased integration of storage resources. We anticipate the system operator will need to adjust the methods used to issue resource operations schedules in order to accommodate these changes.

For example, when configured to represent common industry scheduling procedures (multiday storage scheduling: none; day-ahead unit commitment: 48-hr horizon and 24-hr interval with no SOC targets; real-time dispatch: 2-hr horizon and 1-hr interval with no SOC targets), the PR100 PCM simulations of the existing system (2022) result in no unserved energy[128]. However, the existing fleet is currently unable to reliably meet demand. As utility-scale and distributed renewable resources are integrated into future systems, the challenges of meeting system flexibility requirements are exacerbated and the existing conventional generation fleet and new storage resources cannot meet system demands in some periods under common industry scheduling procedures.

To mitigate the unserved energy events that are shown for the 1LMNet scenario in Figure 148 (page 247), the following adjustments were made to the simulation configuration and the resulting configuration described in Section 9.2:

- The multiday storage scheduling decision stage was added to help inform energy requirements looking ahead several days.
- Storage SOC targets were added to incentivize stored energy at specific periods in each optimization problem based on the results of longer horizon scheduling stages.
- A 500-MW (44%–50% in 2025 and 12%–19% in 2050 of total storage capacity) constant reserve requirement was added to the multiday storage scheduling and day-ahead unit commitment stages to help mitigate capacity availability shortfalls.[129]
- The real-time dispatch stage was given a 12-hr horizon to provide better foresight for storage operations.

[128] Existing system PCM representations assume no forced outages. RA model results reflect observed system performance when representing existing generator forced outage rates.
[129] 500-MW constant reserve requires maintaining a 500-MW power production capability above forecasted system demand at all times from specified resources that include existing qualifying facilities and new utility scale renewable and storage resources. Note that this reserve is only procured in the multi-day and day-ahead scheduling stages, and therefore energy held in reserve can be deployed for balancing in the real-time scheduling stage. Ultimately, the addition of the 500-MW constant reserve creates more conservative multi-day and day-ahead dispatch schedules to support over-forecasted energy production conditions by ensuring that there is always excess energy production capability relative to the expected demand.

After implementing these PCM configuration adjustments, the results shown in Figure 149 demonstrate that the unserved energy events are avoided. Note that the PCM configuration adjustments also increase total thermal generation by reducing the flexibility of storage operations and requiring additional operational reserves.

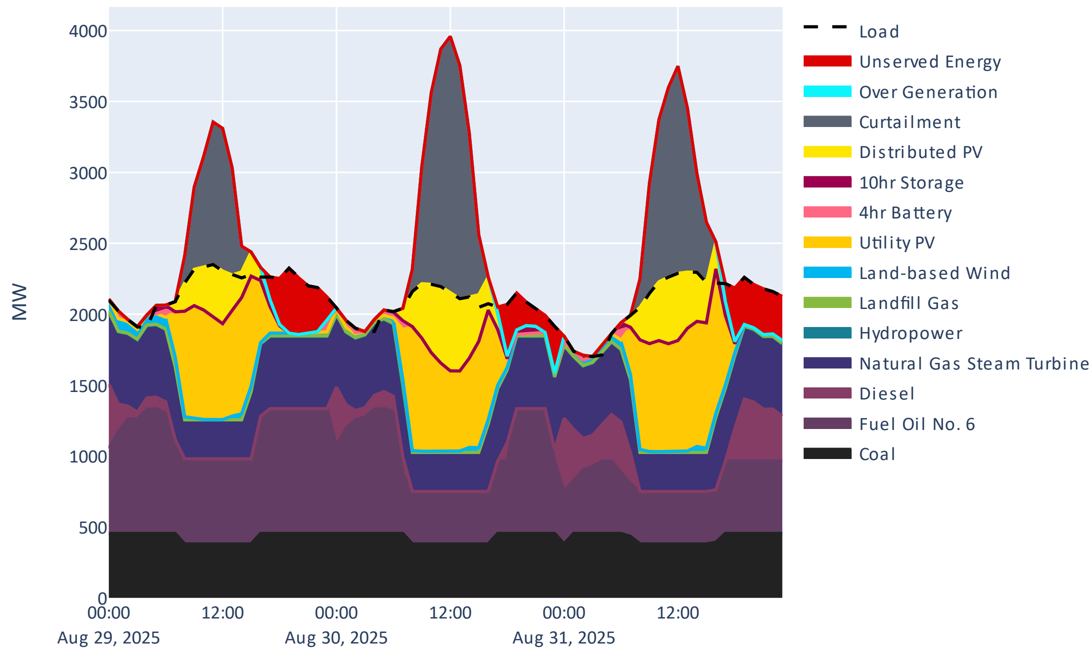

Figure 148. Sample dispatch for 1LM scenario using common operational scheduling configuration (not used for PR100 results)

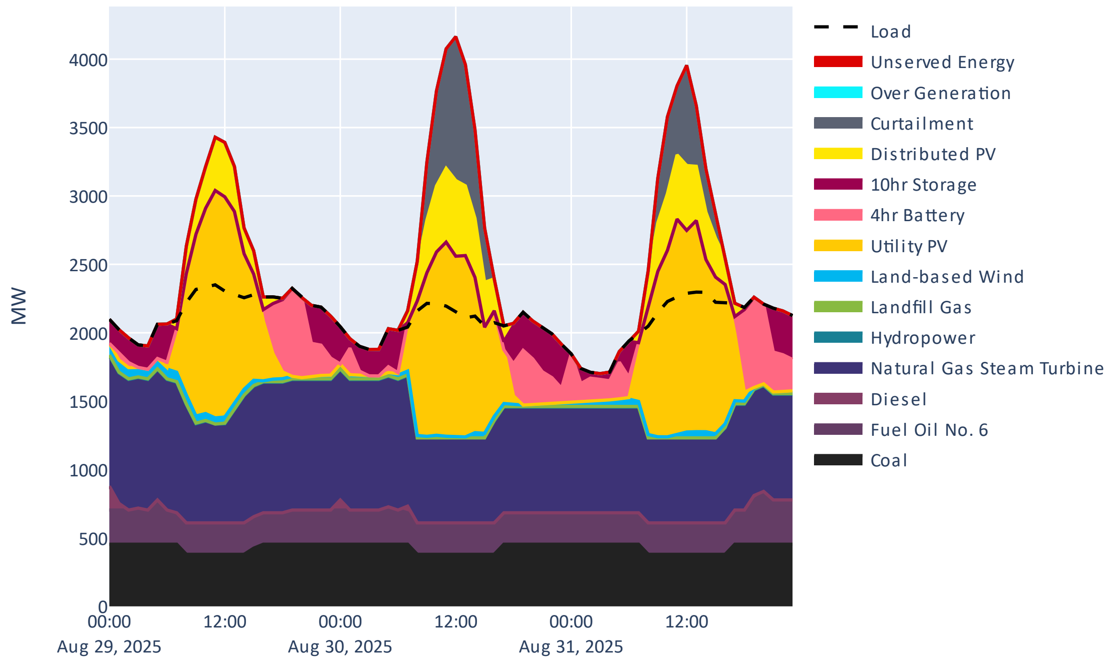

Figure 149. Sample dispatch for 1LM scenario using the PR100 operational scheduling configuration

9.3 Results

Several analyses were conducted to address the bulk power system reliability, adequacy, and security for Puerto Rico's energy system under the various projections established by the expansion scenario-years. Each of the following analysis activities contributed to the process of finalizing simulation results and collecting key findings.

9.3.1 PCM Sample Period Results

For each study year (2025, 2028, 2030, 2035, 2040, 2045, and 2050), hourly system operations are simulated for the whole year using the process described in Section 9.1. By adjusting system operations procedures as described in Section 9.2.1, the PCM generates hourly operational schedules that balance energy production and demand in all simulated periods. Following the transformation of system generation capacities, operational schedules also transform. For example, Figure 150 shows a sample dispatch period surrounding August 30 for the 1LM scenario in 2050. Both the 2025 (Figure 149) and 2050 dispatch show that the system relies heavily on storage and thermal generation to meet nighttime energy demands.

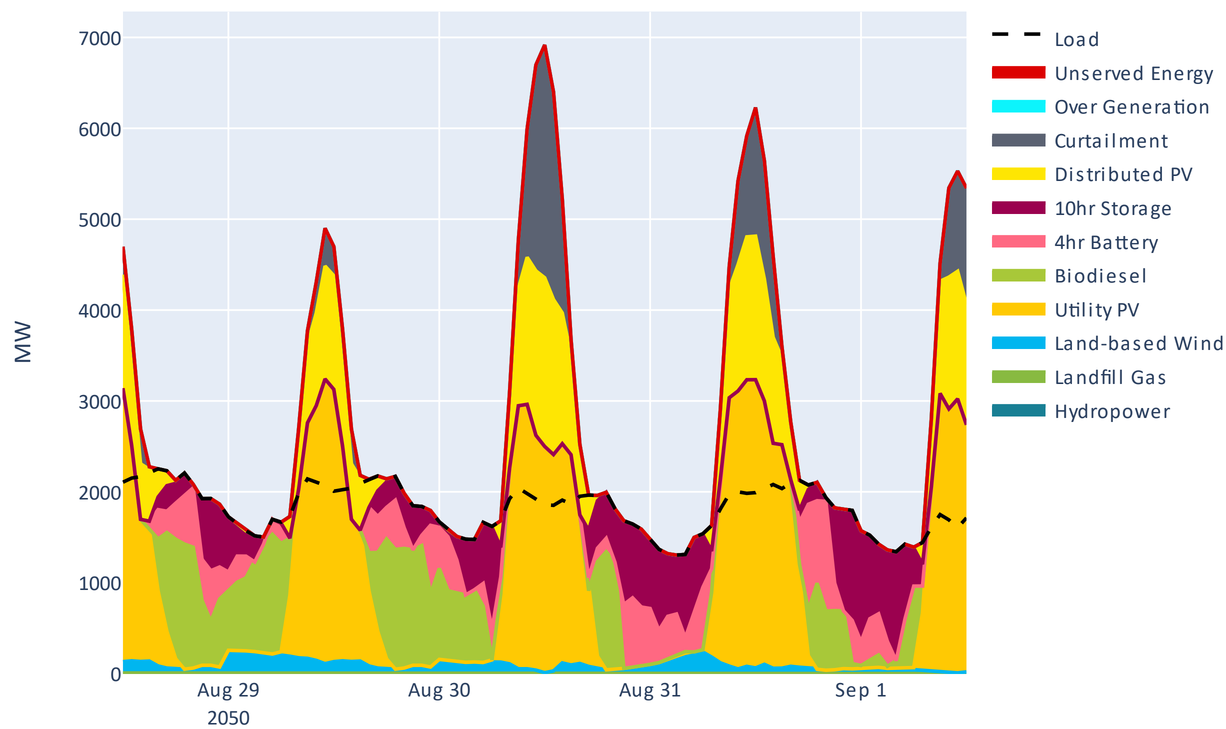

Figure 150. Sample 4-day dispatch for the Economic Adoption, Less Land, Mid case load (1LM) scenario in 2050

Under normal conditions, the 2050 system is extremely challenging to balance due to the large amount of solar generation on the system. In these conditions, common cloudy conditions or forecast errors can introduce complexity into the scheduling problems. The overnight and early morning hours of August 29 and 30 in Figure 150 show increased utilization of biodiesel generation. Figure 151 shows the day-ahead forecasted and realized renewable energy output, and Figure 152 shows the stored energy in the system for the same time period. The relatively low peak stored energy levels on August 28 and 29 is due to the reduced solar output during the daytime hours of those days. As a result, the system cannot fully charge storage resources and must rely on biodiesel to meet system energy demands through the nighttime hours.

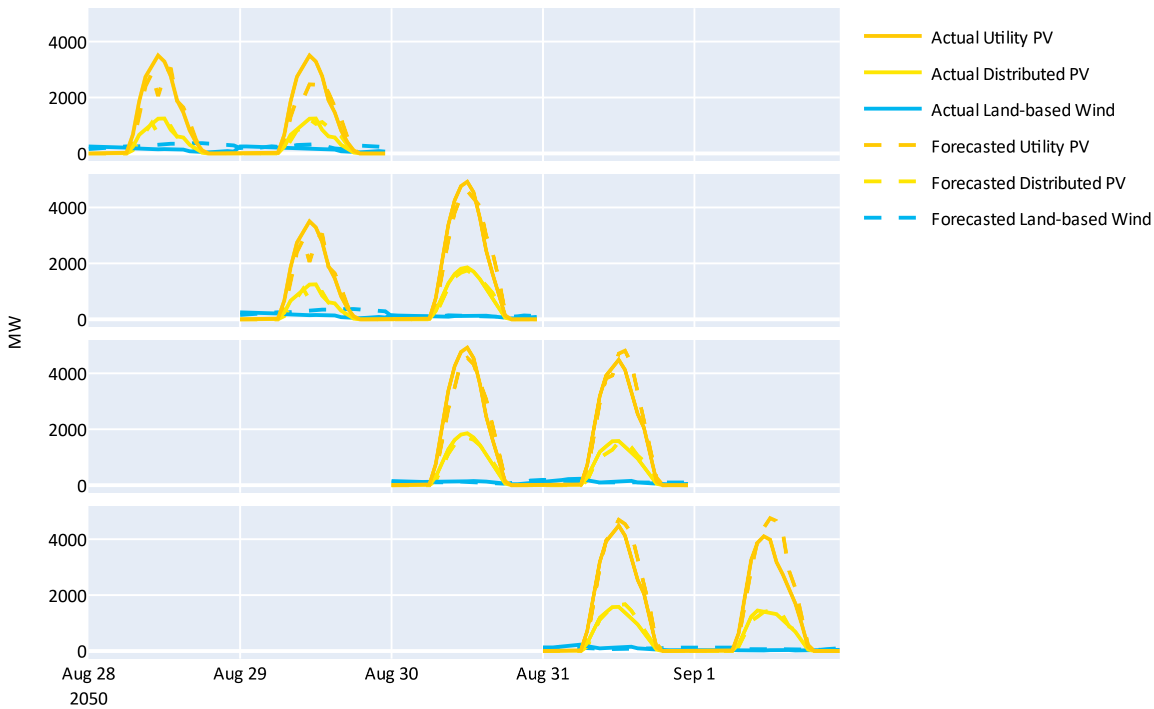

Figure 151. Sample renewable energy forecasted (dashed) versus actual (solid) output for the Economic Adoption, Less Land, Mid Load (1LM) scenario in 2050

The difference between the dashed and solid lines Figure 151 shows that solar production is modestly over-forecasted in the evening periods of August 31 and Sept 1. To accommodate the solar underproduction (relative to forecast), the system must discharge storage earlier/faster than planned and/or dispatch biodiesel generation.

These situations indicate that while the 100% RE system of 2050 creates scheduling challenges, the PCM results show that the projected system build-outs can meet all expected hourly energy demands even while managing forecast errors and cloudy periods.

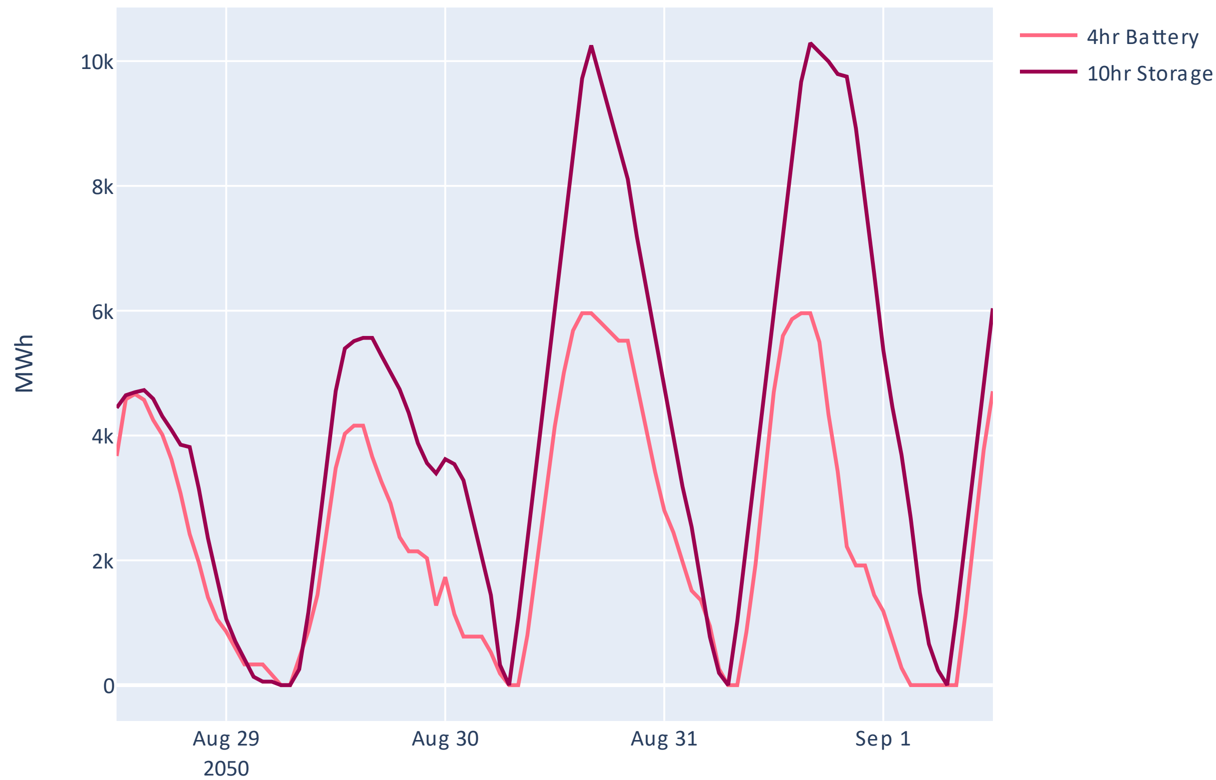

Figure 152. Sample 4-day storage SOC for the Economic Adoption, Less Land, Mid case load (1LM) scenario in 2050

9.3.2 PCM Annual Results

Figure 153 and Figure 154 show examples of the evolution of total energy production for each simulation year for two scenario variations that bookend total utility-scale energy production. Figure 153 shows the total energy production in the Economic Adoption, More Land, and Stress load (1MS) scenario sensitivity, which has the highest total utility electricity production across all scenario-variations in PR100. Figure 154 shows the total energy production in the Maximum Adoption, More Land, and Mid case load (3MM) scenario, which has the lowest total utility electricity production across all scenario-variations in PR100. Results indicate that storage is used as a key resource for balancing throughout the study years. Additionally, the larger wind energy production in the 1MS scenario compared to the larger distributed PV and battery production 3MM scenario indicates the need to use storage to meet electricity demands with energy produced by PV resources. The dominance of utility and distributed PV generaiton creates numerous challenges due to the uniformity of the solar resources on the system. Even with significant utiliity scale storage deployment, the system continues to rely heavily on legacy natural gas generation through 2045 and biodiesel in 2050 to manage forecast errors and meet night time energy demand.

Because the production cost model is a sequential simulation of least-cost grid scheduling, the PCM does not have annual foresight and therefore no capability to require annual production share from any single or group of resources. Therefore, the share of electricity produced by renewable sources is purely an outcome of the PCM simulations based on the resources that are online during any particular scenario-year. The share of renewable energy is indicated in Figure 153 annotations as the relative share of simulated electricity produced by non-fossil fuel-based generation, including distributed generators. The curtailment indicated on the following figures does not count toward the “% RE” figure.

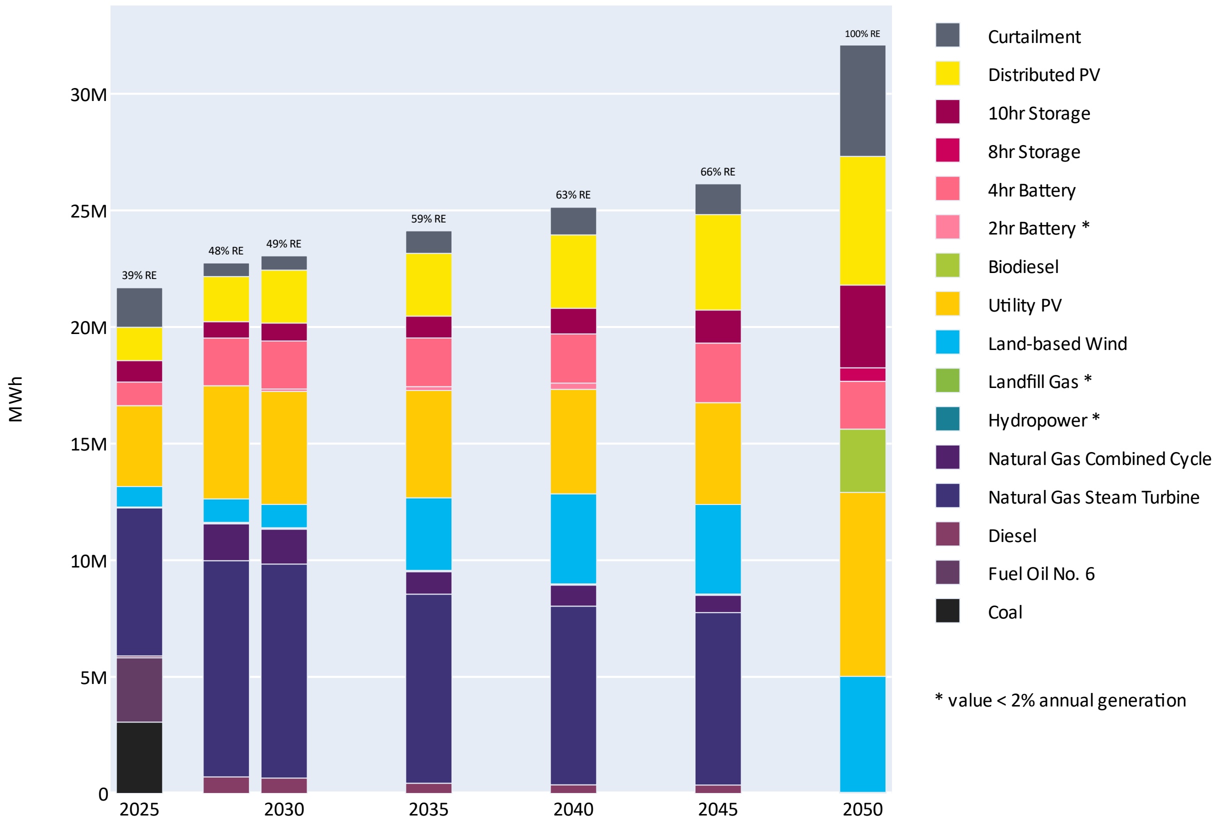

Figure 153. Total annual electricity generation by year for the Economic Adoption, More Land, Stress load scenario (1MS)

Curtailment represents available energy from wind and solar resources that is not produced or generated. Distributed generation resources are not curtailable because they are assumed to be behind the meter and thus not dispatchable by the system operator. Therefore, curtailment occurs when utility-scale PV and wind resources can produce more energy than they are dispatched to produce. Because utility-scale PV and wind resources are represented with zero marginal operational cost, the PCM effectively will minimize curtailment. Nevertheless, curtailment is still observed in simulations of system operations due to the limited flexibility of the fully dispatchable conventional resources (i.e., landfill gas, natural gas, diesel, fuel oil, and coal), transmission limitations, and ancillary service scheduling.

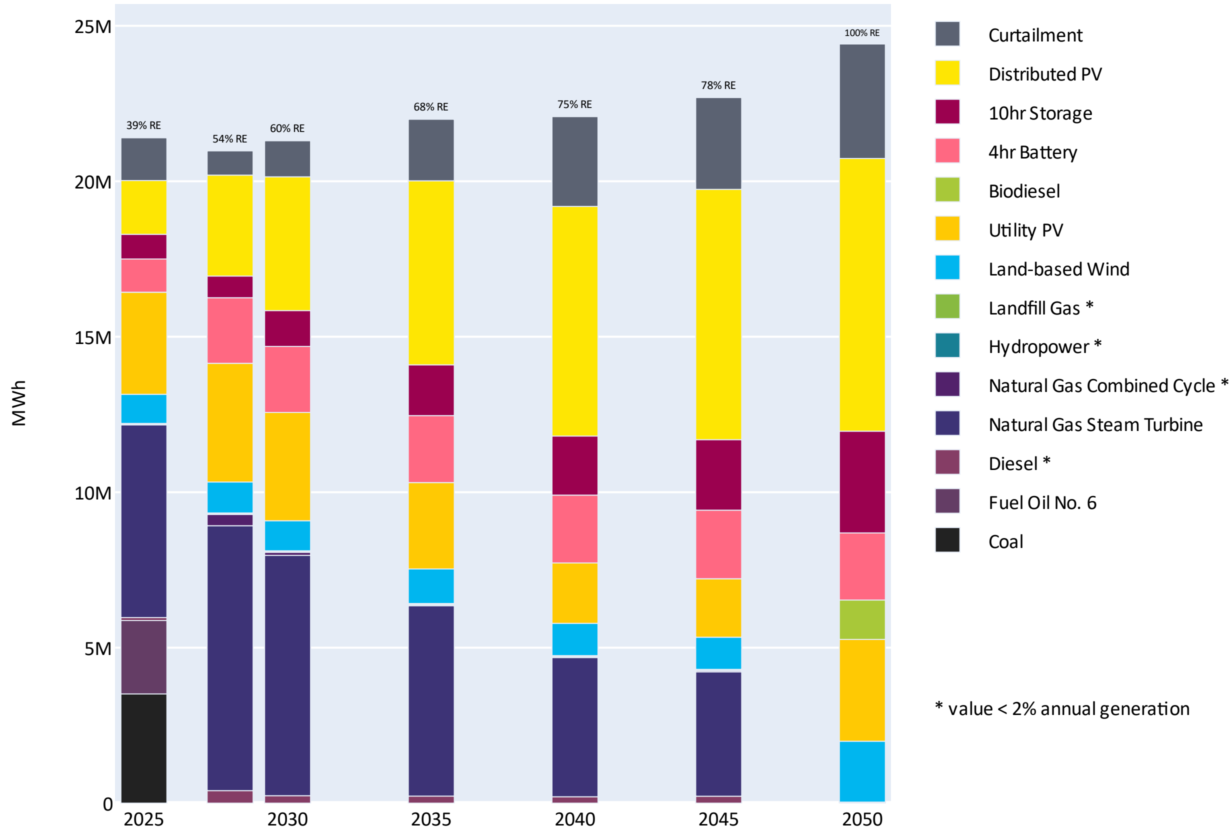

Figure 154. Total annual electricity generation by year for the Maximum Adoption, More Land, Mid case load scenario (3MM)

The production share from each resource is primarily driven by the available generation capacity of each resource type. As spare capacity declines between 2025 and 2028, we observe minimal curtailment of utility-scale renewable resources while significant flexible fossil fuel-fired capacity remains online. However, with the declining share of fossil fuel-fired generation and the increasing shares of distributed solar throughout the study horizon, we see increasing demand for flexible generation resources. This indicates that excess utility-scale PV capacity is often built to maintain resource adequacy (

Figure ES-22) which may not align with current generation procurement mechanisms.

Figure 155 and Figure 156 show the total annual energy production by technology across scenarios for 2025 and 2050 (figures for other study years are included in Appendix H). In the 2025 study year, Figure 155 indicates that all of the scenarios produce 39%–40% of their annual energy with renewable generation sources. By 2028, many of the scenarios[130] reach the 50% renewable portfolio standard (RPS) target that some reach as much as 54% renewable energy.[131]

[130] 2028 results assume all tranche capacity additions and retirements are realized prior to the 2028 study year.
[131] The Engage modeling tool enforces the 40% RPS in 2028 and plans a system that could possibly achieve the RPS. But, due to the sequential simulation process of the PCM, there is no way to enforce constraints on annual

With the retirement of all remaining fossil fuel-fired generation in 2050, Figure 156 shows that every scenario reaches the target 100% RPS. Figure 155 and Figure 156 show the total annual energy production by technology across scenarios for 2025 and 2050 (figures for other study years are included in Appendix H). Differences between scenario generation results are largely correlated to the differences in the resource capacities present in each scenario. This is especially true for distributed PV since it is a non-dispatchable resource and cannot be curtailed. This also drives differences in renewable energy production, especially when comparing the Maximum Adoption scenario (3) where distributed PV capacity, and therefore production, is greatest, with the Economic Adoption and Equitable Adoption scenarios (Scenario 1 and Scenario 2), which have slightly lower distributed PV capacity. The extra distributed PV capacity in the Maximum Adoption scenarios drives additional curtailment from utility-scale renewable generators because the system is required to manage forecast errors, flexibility requirements, and operating reserves with a relatively smaller proportion of utility-controlled resources. Similarly, storage utilization in the Maximum Adoption scenarios is higher than the other scenarios because the non-dispatchable distributed PV must be utilized. Especially during later simulation years when the levels of distributed PV are greater, storage is charged with distributed PV during the day and discharged at night. This dynamic also results in reduced fossil fuel-fired generation.

energy production from any resource. Therefore, the PCM results indicate annual energy production from economic system scheduling. Additionally, inconsistencies between the PCM operational results and the operational requirements represented in the Engage modeling tool are expected since the Engage modeling tool neglects several operational details including the physics of electrical power flow, inter-temporal generation constraints, and operating reserves.

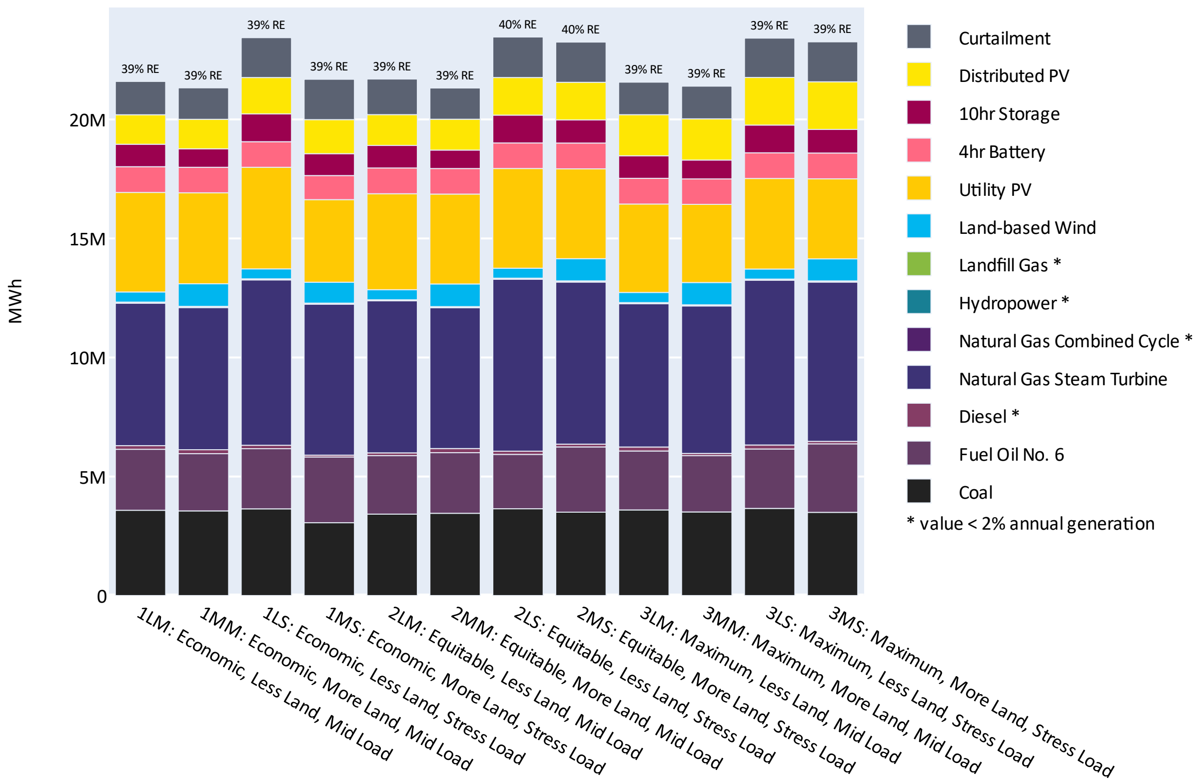

Figure 155. Total annual electricity generation by scenario for the 2025 study year

When comparing the annual generation of the Less and More Land scenario variations, we often see greater wind generation in the More Land variations. This is consistent with the extra wind capacity resulting from more suitable land available for wind development in the More Land variations. However, we also see either reduced energy provision from storage (battery) resources, or reduced fossil fuel-fired generation in the More Land variations relative to the Less Land variations. This indicates that the timing and/or location of wind energy production is well correlated with system requirements, thus avoiding the need to run fossil fuel-fired generators or to shift the timing of energy production with storage resources.

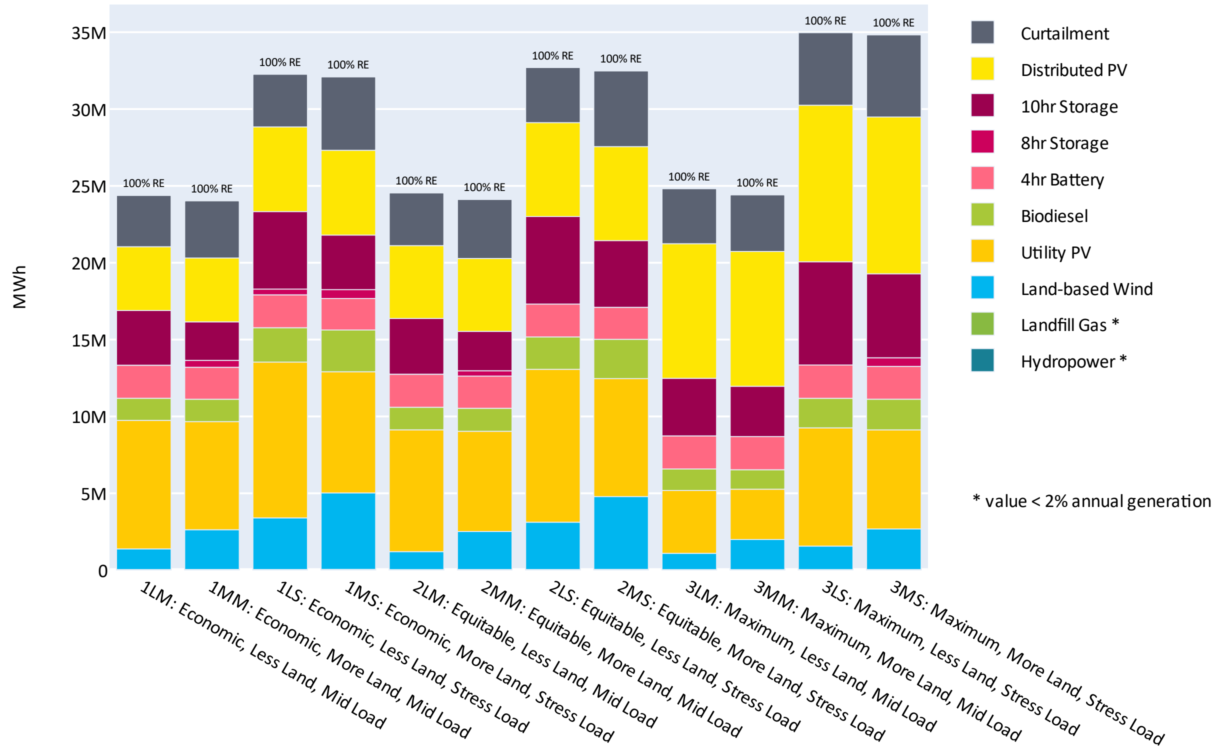

Figure 156. Total annual electricity generation by scenario for the 2050 study year

Figure 157 shows the average annual capacity factor each utility-dispatched technology across simulation years for the 1LM scenario. The increase in fossil fuel-fired capacity factor in 2028 is due to the retirement of the coal generation and the resulting additional utilization of the remaining fossil fuel-fired generators to meet system demands. As more renewable generation is integrated in future years, the capacity factors of the remaining fossil fuel-fired generation decrease from the elevated 2028 values but remain higher than in 2025.

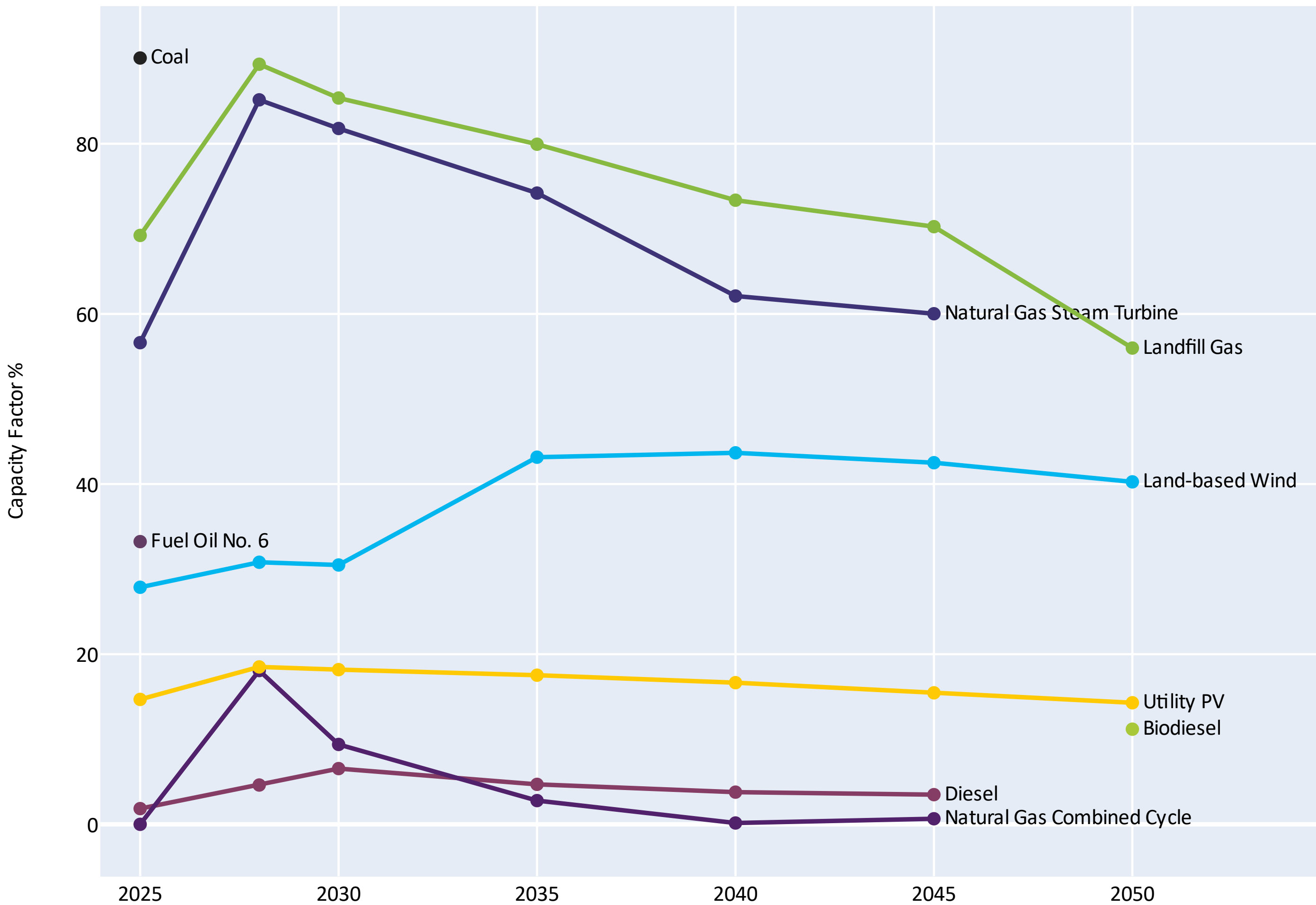

Figure 157. Average capacity factor by technology for each simulation year in the Economic Adoption, Less Land, Mid case load (1LM) scenario

Several minor differences are highlighted when examining capacity factors of different technologies across the scenarios in 2028 and 2045 in Figure 158 and Figure 159 respectively. First, in 2045, the Less Land scenario variations have higher capacity factors across virtually all technologies than the More Land scenario variations. This is due to the reduced wind and increased PV deployment in the Less Land scenario variations relative to the More Land scenario variations and the corresponding need to operate more utility-dispatched fossil fuel-fired generation. This trend is reversed (higher capacity factors in More Land scenario variations) because PV capacity is higher in the More Land variations because economically attractive PV is developed early and wind capacity is expanded later by the Engage modeling tool. Also, the scenarios that have more distributed PV capacity result in higher capacity factors than those that deploy less distributed PV. Again, this occurs because the system operator is forced to manage variability, forecast errors, and other system requirements with fewer resources, thereby forcing the increased utilization of more expensive fossil fuel-fired generation technologies.

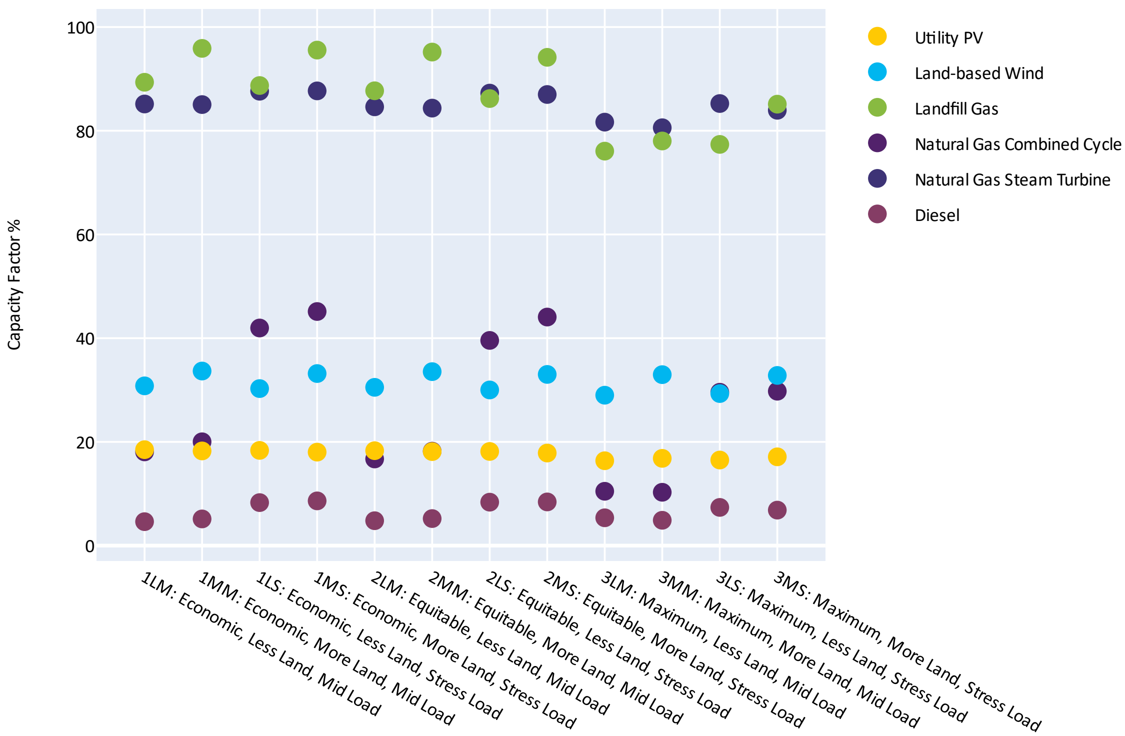

Figure 158. Average capacity factor by technology for each scenario in 2028

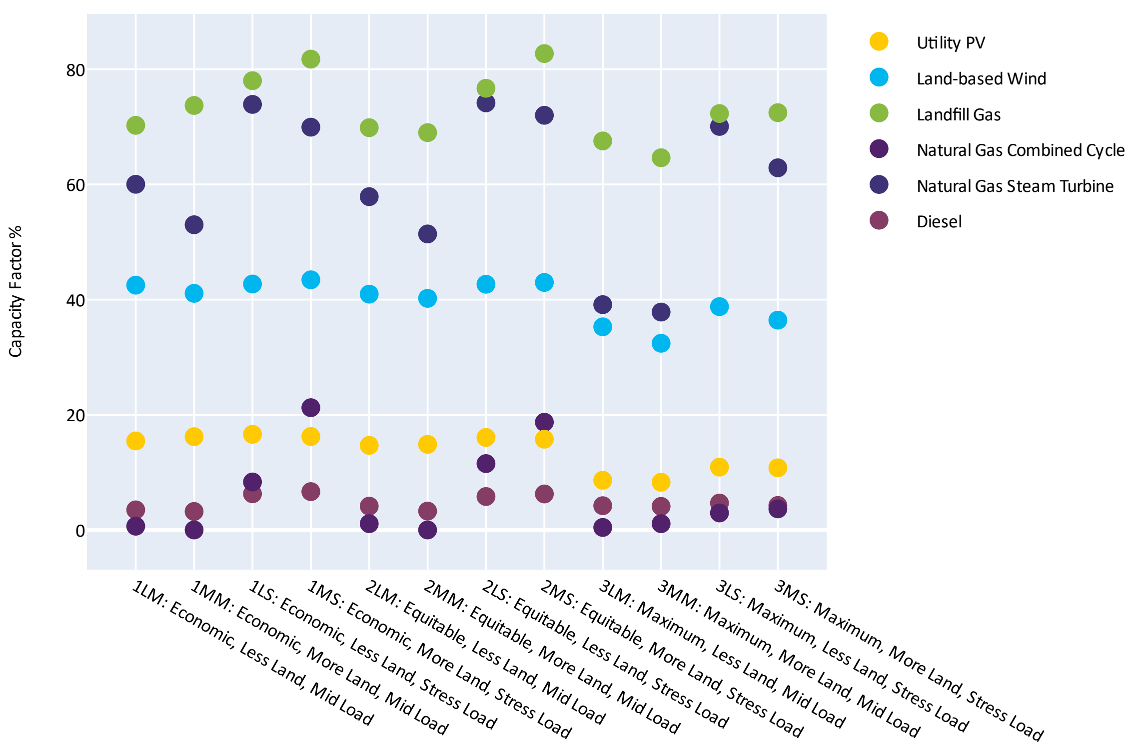

Figure 159. Average capacity factor by technology for each scenario in 2045

Figure 160 shows the distribution of total curtailment in each hour of the day for all days in 2050 in the 1LM scenario. As expected, the bulk of the curtailment corresponds to the peak PV production periods. This is confirmed in Figure 161, which show distributions of the share of utility PV and wind curtailment relative to total curtailment for each hour of the day for all days in 2050 in the 1LM scenario. Figure 162 shows the average SOC for each battery in the system in each hour of the day across every day in 2050 for the 1LM scenario. The SOC figure indicates that batteries virtually always operate with a daily charge discharge pattern; they charge during the day, often reaching full charge by 9 a.m. or 10 a.m. and then discharge during sunset and into the night. The saturation of battery states of charge relatively early (9 a.m.–10 a.m. rather than afternoon) in combination with the large proportion of PV curtailment indicates additional energy storage resources could provide additional benefits.

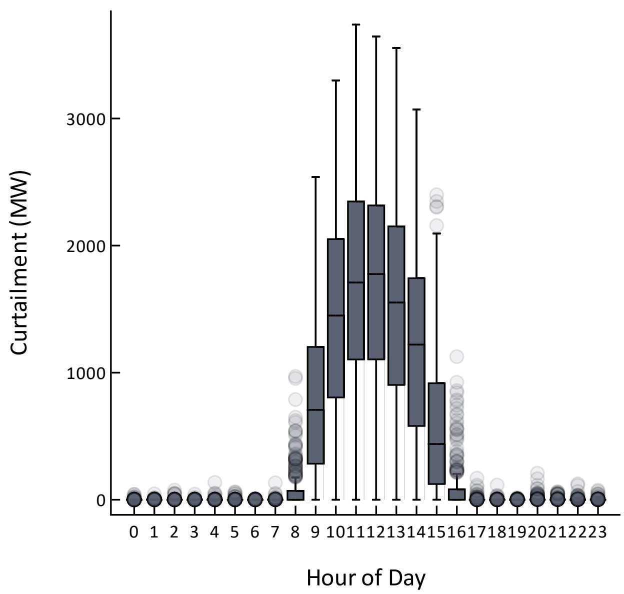

Figure 160. Distribution of the total curtailment in each hour of the day for all days in 2050 in the Economic Adoption, Less Land, Mid Load scenario

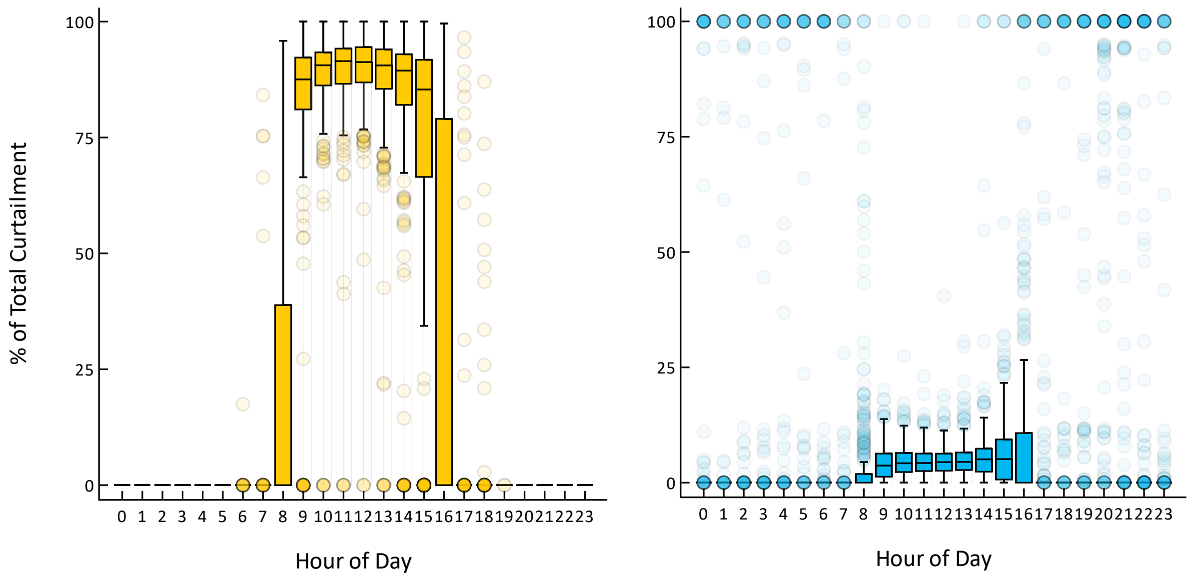

Figure 161. Distribution of the proportion of total curtailment from utility PV (left) and wind (right) in each hour of the day for all days in 2050 in the Economic Adoption, Less Land, Mid Load scenario

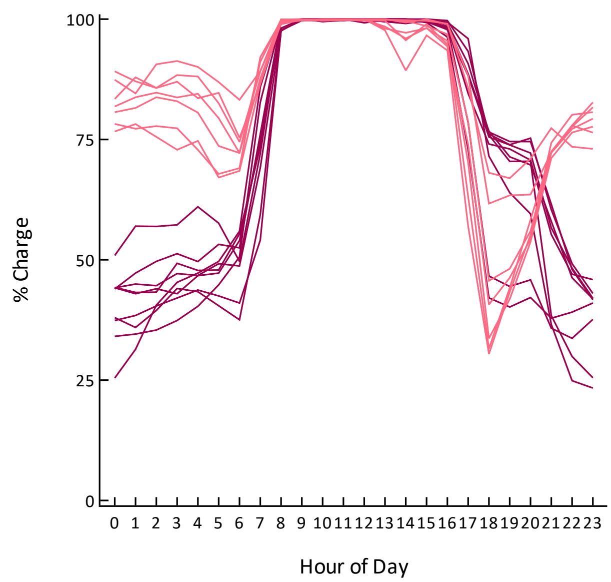

Figure 162. Average battery SOC in each hour of the day for all days in 2050 in the Economic Adoption, Less Land, Mid Load scenario

These results suggest the principal drivers of curtailment are the lack of generating fleet flexibility and the need to procure enough capacity to ensure RA. Transmission limitations occasionally contribute to curtailment (Section 9.3.3). However, the PR100 results indicate the high-voltage transmission network is not the principal factor limiting greater utilization of renewable resources.

9.3.3 Transmission Impacts

To maintain PCM computational tractability, we ignore the effects of voltage and reactive power and represent only active power flows in the transmission network. Additionally, the PR100 PCM does not represent any transmission contingencies or flow limits on transmission elements rated below 115 kV. Figure 163 shows the transmission lines (38 kV and above). Lines are shaded by the amount of time they are utilized above 90% of their rating (i.e., are "overloaded") during daytime (top) and nighttime (bottom) periods in the 1LM scenario. Additionally, the substation interconnection locations of wind and utility PV generators in the 1LM scenario are indicated along with delineating the lower-voltage elements with solid lines. The maps indicate that congestion is more prevalent during daytime hours but does not appear to be driven solely by utility PV generation. Instead, the locations of the red (overloaded > 25% of the time) are often coincident with locations where distributed PV adoption results in large negative net loads. However, in the bottom (nighttime) map, many of the heavily loaded (purple and red) lines are coincident with wind generation locations.

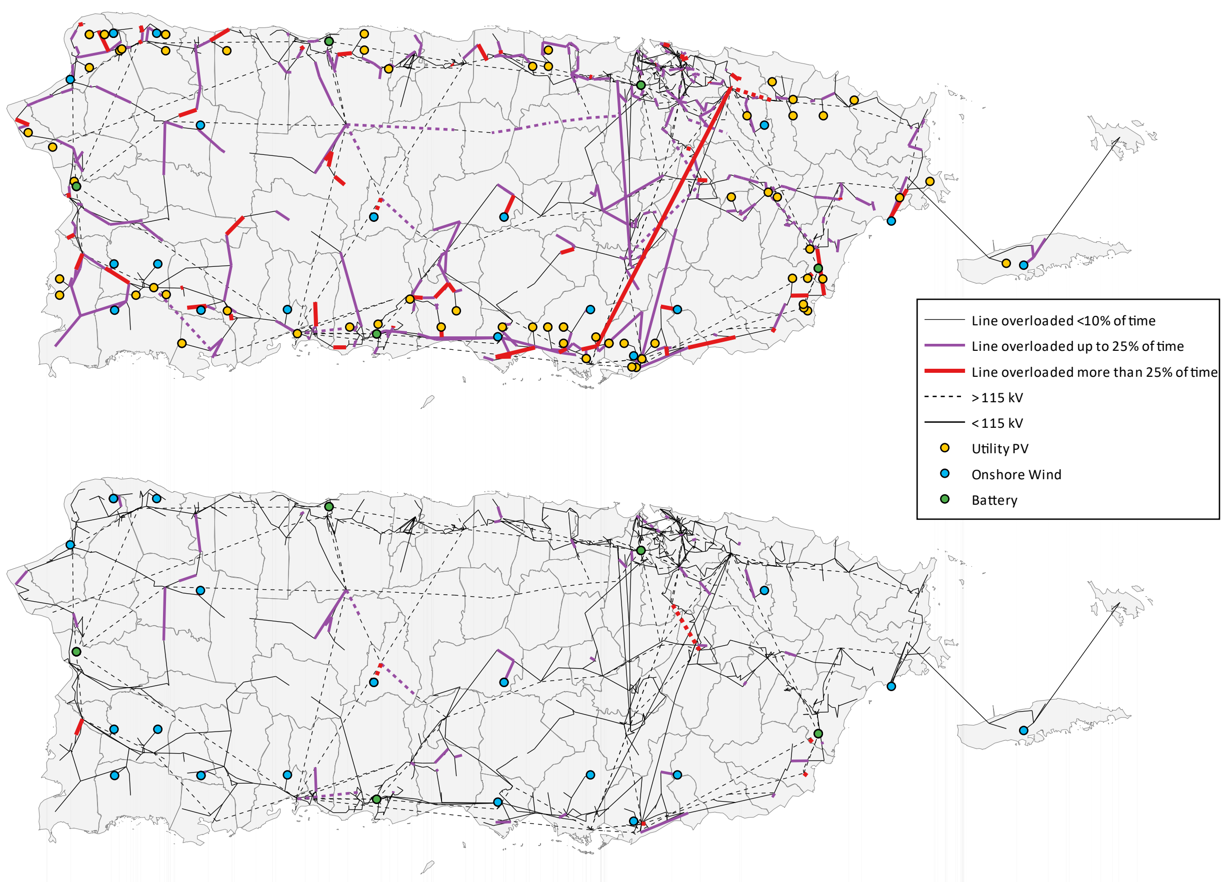

Figure 163. Percentage of daytime (top) and nighttime (bottom) overloaded line hours for the Economic Adoption, Less Land, Mid Load Case (1LM) scenario

Figure 164 and Figure 165 show the distribution of transmission line loading for 2025 and 2050 (figures for other simulation years are included in Appendix H, page 698). The box plots show the median and 25th and 75th quantile of loading values for all lines and for each transmission voltage level. The whiskers on the boxplots extend to include the 5th and 95th percentile loading values. Figure 164 indicates that the 230-kV network is consistently heavily loaded in 2025 in all scenarios. The persistence and relatively heavy utilization of the existing fossil fuel-fired generators (see Figure 153), which are tightly coupled to the 230-kV network, lead to heavy 230-kV line loading. This trend continues and consistently declines proportionally to the declining existing fossil fuel-fired fleet utilization through 2045 (see Figure H-5, page 702 in Appendix H). Because the renewable generation injections are more distributed, both from distributed PV locations at virtually all demand nodes and from diverse interconnection locations for utility PV and wind resources, the resulting power flows become more evenly distributed across the rest of the transmission network as the share of renewable energy increases.

Recall that the PCM is configured with relaxed flow limits on 38-kV lines because of the uncertainties associated with specific renewable interconnection points and demand changes, so 38-kV overloads are expected. In fact, all scenarios in all simulation years result in overloads in the 38-kV network. Figure 165 shows that in 2050, the 95th percentile of line loading values approaches 120% of the 38-kV flow ratings in the Stress load variations for the Economic Adoption and Equitable Adoption scenarios. This is coupled with a significant decrease in 230-kV loading across all scenarios from the retirement of the remaining fossil fuel-fired generators.

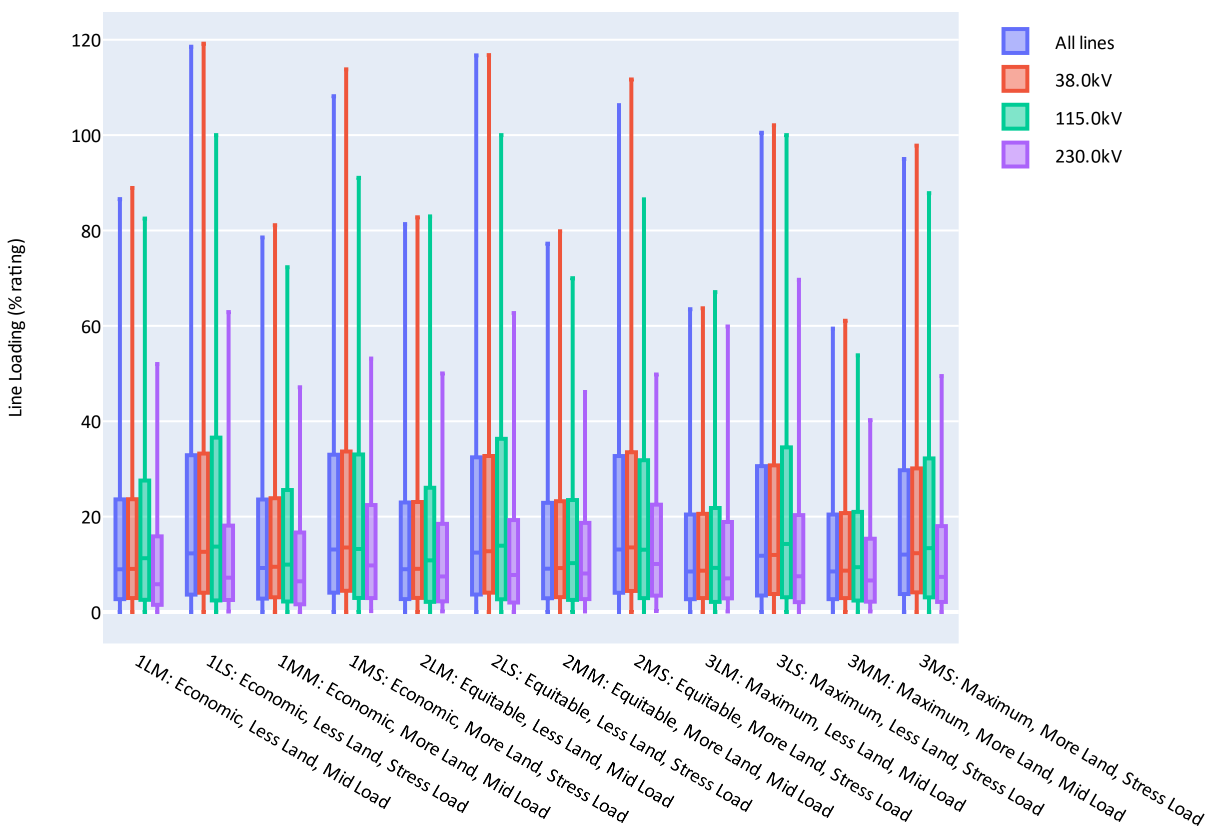

Figure 164. Distribution of transmission line loading in all periods of 2025 by scenario

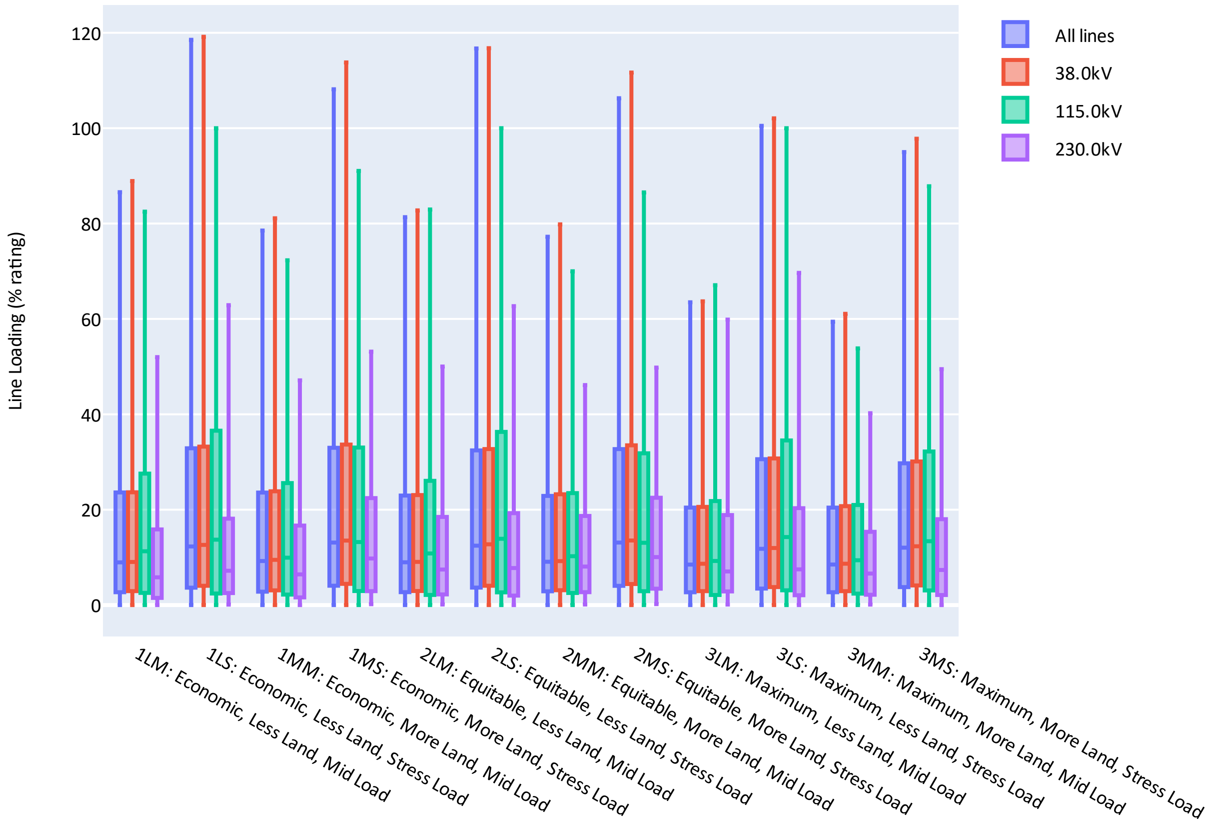

Figure 165. Distribution of transmission line loading in all periods of 2050 by scenario

9.3.4 38-kV Network Analysis

Figure 166 shows the sum of non-coincident peak 38-kV line flow violations in each scenario and year. This metric is an estimation of a theoretic upper bound for the amount of 38-kV transmission upgrades that would facilitate all flows simulated in the PCM. This estimate does not account for impedance changes that would necessarily result from any transmission line upgrades. Nor does it consider the value of transmission upgrades. Rather, Figure 166 should be considered an illustration of the total magnitude of violations that occur in the PCM simulation under grid evolution (new utility-scale generation development, distributed generation adoption, and changes in demand) scenarios that do not consider the 38-kV network constraints. Before implementation, these violations would need to be mitigated by options that could include:

- **Utility-Scale Storage and Generation Siting:** Significant deployment of utility-controlled energy storage and generation technologies are modeled across all PR100 scenarios. However, the interconnection location selection process did not consider 38-kV network limitations, and detailed analysis to select the optimal interconnection locations was not in the scope of PR100. Some of the 38-kV network violation could be mitigated with optimal siting and management of generation and energy storage resources.
- **Transmission Topology Reconfiguration:** The physics that govern network electricity flow occasionally results in a situation where removing specific lines from service can improve the overall transfer capacity of the network (Tsuchida and Gramlich 2019). Though finding these solutions can be computationally complex, once solutions are found they can often lead

to improved network flows for long periods of time, thus avoiding the need for specialized hardware to facilitate frequent topology changes. Other situations might exist where grid-enhancing technologies could provide value if deployed and properly managed (DOE 2022a).

- **Transmission Expansion:** Because of the magnitude of violations, it may be necessary to increase transmission network capacity by adding power flow controllers, or through reconductoring, replacement, or expansion of transmission lines (especially at the 38-kV level). This is likely the most expensive mitigation option, but it might be required in some cases to support the desired transition.

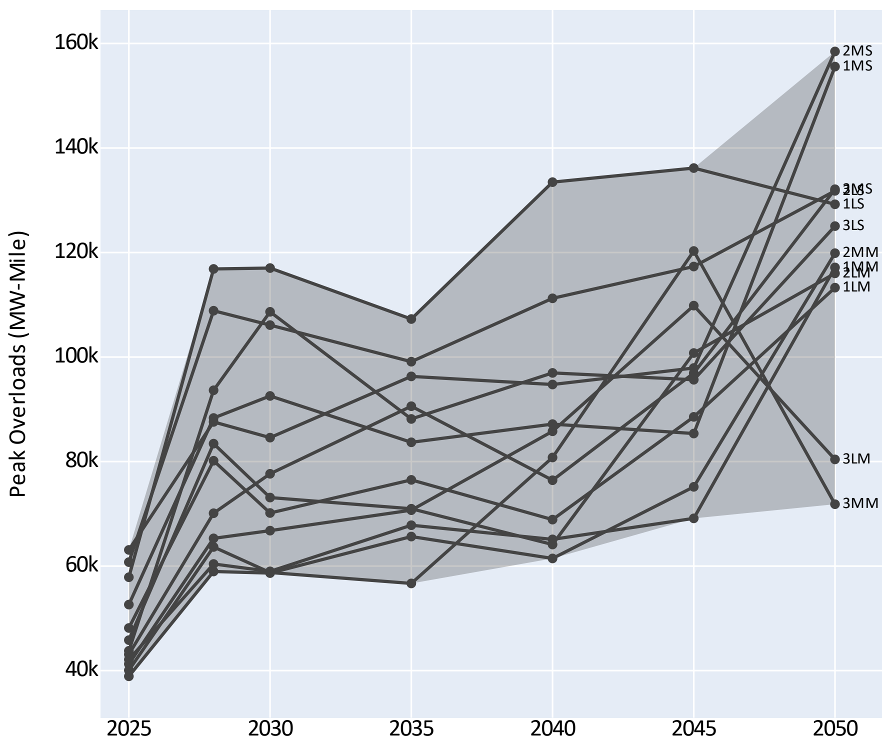

Figure 166. Sum of peak (non-coincident) 38-kV line flow limit violations

9.3.5 Generator Cycling Analysis

Economic integration of renewable energy on Puerto Rico's grid will affect the operation of existing fossil fuel generating units. Because of the low marginal operating cost of PV and wind generators relative to the fuel and other variable costs of fossil-fueled generation, the PCM will economically dispatch PV and wind in lieu of other technologies whenever the system constraints will allow. In this section, we analyze how existing unit operations change as the system evolves under different scenarios. Changing existing unit operations can affect unit reliability, usable lifetime, and maintenance and repair costs. We do not consider unit reliability or operations and maintenance cost changes in our analysis. However, we focus this analysis on the frequency and duration of thermal generator cycling because it is a principal area of concern surrounding the operation and maintenance of these existing units. Specifically, Figure 167 and Figure 168 show the number of cycling events per year and the downtime duration for each thermal generator type of Less Land (dashed) and More Land (solid) variations of each of the Economic Adoption (1) scenario and Stress (S) Load variations (figures for other scenario variations are included in Appendix H, page 698). The results suggest that 40% renewable energy (2025) requires relatively frequent cycling of natural gas units. This is a result of integrating substantial wind, utility-scale PV and distributed PV resources while still relying heavily on the relatively inflexible, coal generation. Once the coal generation is retired after 2025, the natural gas steam turbine generation operates more consistently until renewable generation further increases. Across all the scenarios and variations, the land use variations have a notable impact on thermal generator cycling. The More Land variations tend to result in fewer cycling events and longer downtimes because they result in more wind capacity deployment, which results in more resource diversity and fewer diurnal shutdowns than when more utility-scale PV is deployed.

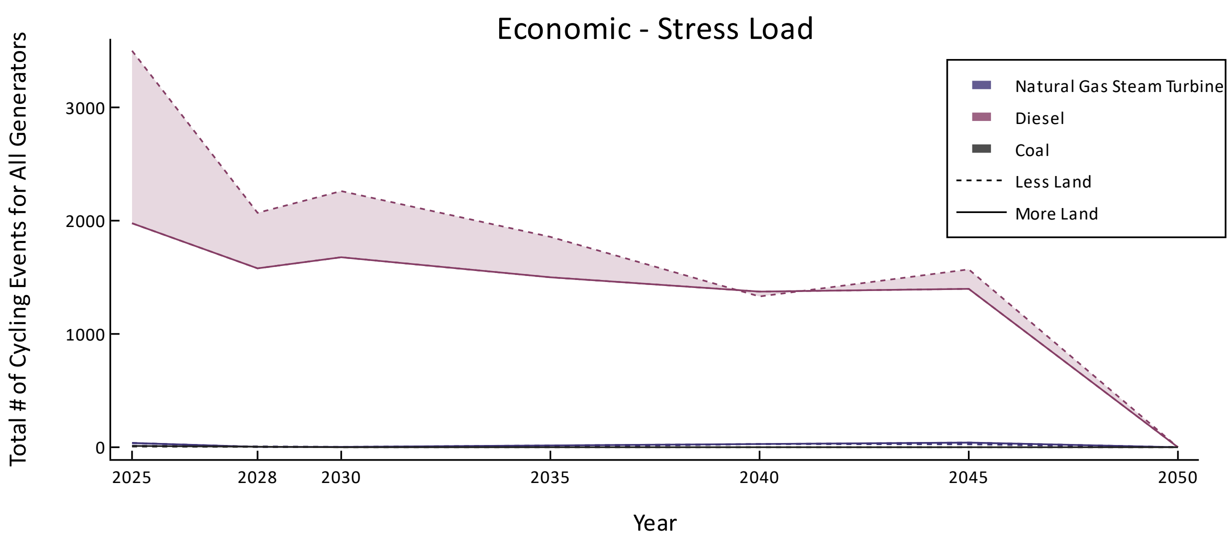

Figure 167. Fossil-fueled generator cycling for Economic Adoption scenarios under the Stress load variation (1*S)

Figure 168. Fossil-fueled generator downtime duration for Economic Adoption scenarios under the Stress load variation (1*S) Operational Cost

Thermal generation is the only technology modeled with a marginal generation cost in PR100. Figure 169 indicates thermal generation declines significantly and consistently throughout the study horizon. However, Figure 170 indicates the system operational costs declines are not proportional to the generation declines. This is due to two factors. First, the retirements of some thermal generators result in generation shifts between generation types with different operational costs. For example, after coal is retired in 2025, natural gas generation increases substantially. Existing gas generation is more expensive than the existing coal generation. Second, fuel prices are assumed to increase over time (see Section 8.2.3, page 215), further adding the cost of thermal generation in future years.

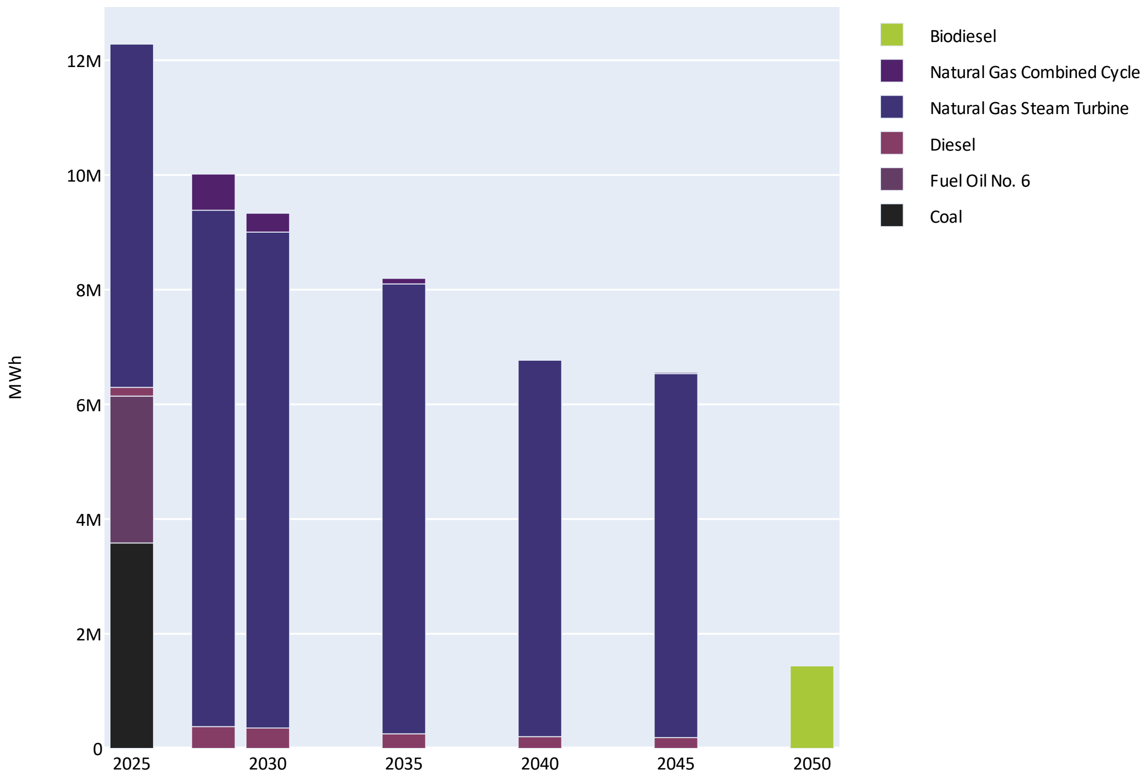

Figure 169. Thermal generation in the Economic Adoption, Less Land, Mid Load scenario (1LM)

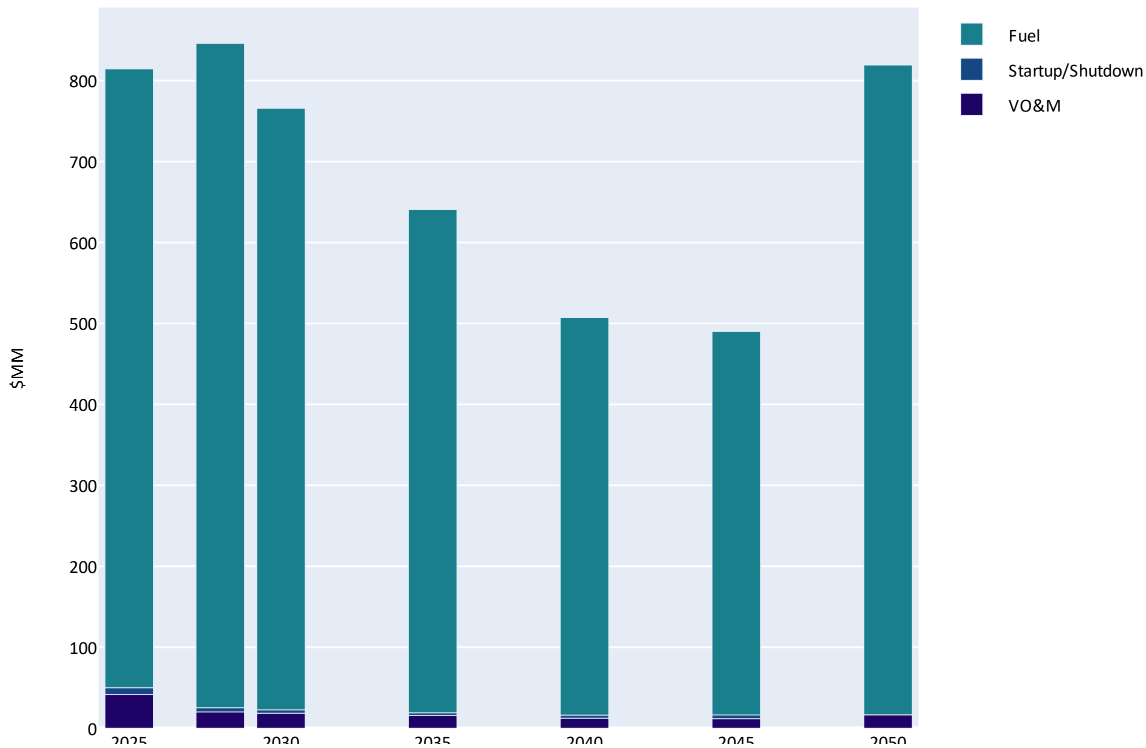

Figure 170. Total annual operation cost in the Economic Adoption, Less Land, Mid Load scenario (1LM)

10 Bulk System Power Flow, Dynamic, and Resilience Impact Analysis

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Section Summary

This section focuses on modeling and analysis of the physics of the Puerto Rico power grid to assess system reliability and resilience. The reliability modeling aspects include the ability of the system to operate with acceptable performance in normal conditions and under contingencies, as evaluated by modeling active and reactive power flows, voltage control, frequency control, and grid stability. The resilience aspects include estimating the possible damage that transmission, distribution, and generation infrastructure may suffer from hurricanes, as well as evaluating the ability of the power system to recover from severe hurricane damage. This section emphasizes the study of near-term scenarios, out to 2028, where significant growth of distributed and utility-scale renewables is expected, including operation with 100% renewable generation for some hours (instantaneous penetration). System operation should always be reliable, including those operating hours with 100% renewable generation. We analyzed the need for additional equipment and control system requirements to reliably operate the bulk power system (38 kV, 115 kV, and 230 kV). The resilience analysis of the bulk power system focuses on system recovery simulations of 100 hurricane events.

This section presents the analysis in eight main parts:

- AC power flow analysis to evaluate the needs for additional voltage control equipment to maintain voltages within limits and manage volage fluctuations from the variable output from distributed and utility-scale renewables
- Grid strength analysis to identify potential need for protection system upgrades, stability concerns, and need for synchronous condensers or equivalent equipment to resolve these concerns
- Model tuning to improve dynamic grid models for a better baseline of analysis
- Electromagnetic transient (EMT) stability analysis for very near term for highest-resolution modeling of renewable generation and battery energy storage systems (BESS) with grid-supporting functions in grid-following (GFL) mode, particularly for Tranche 1 projects
- Stability analysis for 100% instantaneous inverter-based resources (IBR) penetration and grid-forming (GFM) controls in BESS and solar photovoltaics (PV) to be able to operate the system
- Load dynamics and distributed energy resource (DER) modeling to capture interactions between DER and loads that may cause unwanted disconnections of DER potentially compromising reliability

- System black-start using grid-forming BESS to begin considering replacement of fossil fuel resources that currently provide black-start service
- Resilience analysis to estimate possible damage to generation and transmission and distribution infrastructure from hurricane events as well as studying the ability of the future system to recover from severe hurricane damage.

Key Findings

- Additional voltage support equipment is needed for mitigating voltage fluctuations in transmission and subtransmission networks due to variable generation output from distributed and utility-scale renewable resources (1,200 Mvar for 3LS 2028). (Section 10.2, page 272)
  - Solar plants and batteries connected to 38 kV could provide part of this requirement if they are located where voltage support is needed.
  - Dynamic voltage support equipment is needed to deal with voltage fluctuations produced by variability of distributed and utility-scale solar generation. Dynamic voltage control equipment includes technologies like STATic synchronous COMpensator (STATCOM), Static VAr Compensator (SVC), and synchronous condensers. On the other hand, less expensive equipment like fixed and switched capacitors and reactors cannot follow voltage fluctuations as efficiently.
  - Line overloads should be resolved through transmission expansion before voltage support equipment is designed and placed.
- To operate the system in moments of 100% inverter conditions, synchronous condensers (1,600 megavolt ampere [MVA] total) or equivalent equipment are needed to increase grid strength. Additional protection system studies are also needed. (Section 10.3, page 280)
  - Synchronous generators could provide part of this requirement. Additional technologies such as battery storage and STATCOM can also improve grid strength.
  - Remote and rural locations show very little change in grid strength and experience some of the lowest strength.
  - Roughly half the capacity is needed when placing synchronous condensers at the 115- and 230-kV transmission levels as compared to existing plant locations.
- The Puerto Rico power grid with Tranche 1 projects is expected to have satisfactory transient performance when all inverters operate with GFL mode, with existing minimum technical requirements. (Section 10.5, page 296)
  - All GFL BESS need both active and reactive power controls for grid support.
  - For electromagnetic transient (EMT) simulations, vendor-specific models need to be integrated into the electromagnetic transient model.
  - Faults anywhere in the 230-kV transmission impact the whole system, and faulted lines or substations need to be isolated as soon as possible.
- Simulations show large voltage and frequency deviations for fault-induced delayed voltage recovery (FIDVR), caused by motor load stalling, followed by DER tripping by low voltage. Additional studies of this problem are needed. (Section 10.6, page 307)
- GFM inverters will be key for Puerto Rico to operate with high renewables in the short term. (Section 10.6, page 307 and Section 10.8, page 330)

- To mitigate the large frequency deviations, 300–830 MW of BESS with GFM functionality will be very beneficial. Having the ability of using fast frequency response, with droops as aggressive as 1%,[132] would be very useful to stabilize the system under stress. (Section 10.6, page 307)
    - BESS with GFM inverter could black-start the transmission system; implementation of a small project in the short term could be beneficial for system operators to gain experience with this technology and plan for replacing fossil fuel-based resources used currently for black-start. (Section 10.8, page 330)
- Recovery after hurricanes can potentially be better for cases with more DERs if all resources participated in the recovery process. (Section 10.9, page 335)
    - A change of paradigm is required for renewables (DERs and utility-scale renewables) and storage to participate in recovery; GFM controls and black-start capability are required.
    - Transmission and distribution recovery to supply 90% of the load is similar for 2028 cases with maximum and economic DER adoption; further study of location and sizing of utility-scale resources is recommended.
    - The profile of the last 10% of load to be recovered is better for the 2028 case with maximum DERs (this implies DERs participate in the recovery process, which is a paradigm change from current capabilities, as mentioned previously).
    - Initial unserved load is lower for the case with maximum DERs.

Considerations

- The Puerto Rico grid would benefit from additional voltage support equipment to bring voltages within acceptable limits and compensate for voltage fluctuations originated from the variability of distributed and utility-scale renewables in the transmission network, especially at 38 kV level. Voltage support equipment would best be a mix of dynamic voltage control devices, like STATCOM, SVC, and synchronous condensers, and static voltage control equipment, like fixed and switching capacitors and reactor banks.
- The Puerto Rico grid would benefit from additional exhaustive contingency studies such as those required in NERC TPL standards.
- The Puerto Rico grid would benefit from additional analysis for optimally sizing and placing synchronous condensers considering alternative technology solutions, remaining synchronous generators, and constraints like cost and location suitability.
- The Puerto Rico grid would benefit by assessing existing protection systems, which may not operate with the lower available fault current (low grid strength), for a high inverter-based generation portfolio.
- Evaluating generator equipment in the field in detail would provide more accurate input to the models and potentially highlight differences of equipment enabled in the field to that in the model. LUMA has contracted personnel to conduct this in-field evaluation.
- The Puerto Rico grid would benefit from implementing real-time high-resolution grid measurement systems (phasor measurement units) and associated communication infrastructure to facilitate various reliability and stability enhancement activities, like generation and storage model validation, contingency event investigation, including FIDVR, DER tripping, oscillations and resonance, as well as real-time situational awareness.
- For Tranche 1, the Puerto Rico grid would benefit from setting up all inverters to operate with voltage and frequency supporting functions even in GFL mode (with existing minimum technical requirements), to ensure the system satisfactory transient performance.

[132] It is important to note that even though 1% droop can be considered an aggressive frequency response contribution, the value is within the range provided in IEEE 2800-2022 Standard. The Standard defines proportional fast frequency response (FFR1) droops between 1% and 5%.

- The Puerto Rico grid would benefit by making both active and reactive power controls available for GFL BESS. All substation level utility-scale BESS plants need to be integrated into the automatic generation control (AGC) system. Controls for inertial response, fast frequency response (FFR), primary frequency response need to be available. Voltage and reactive power controls need to be available.
- The Puerto Rico grid would benefit by ensuring vendor-specific models are integrated into the electromagnetic transient model of the LUMA system.
    - Advanced inverter controls, like grid-forming, voltage, and frequency supporting functions, are key for when the system approaches 100% instantaneous inverter penetration.
    - In the near term, install GFM and black-start controls on energy storage and grid-supporting controls in all renewable generation with connection to an AGC system.
    - In the long term, install advanced controls like GFM in all resources.
- The Puerto Rico grid would benefit from ensuring utility-scale renewables and battery storage have robust settings for low and high-voltage ride-through capabilities to avoid disconnection during low-voltage conditions that could happen during FIDVR and other events. Improved system protection would provide better stability during severe faults.
- The Puerto Rico grid would benefit from adopting IEEE 2800 Standard as a base for requirements for IBRs and defining specific requirements for inverter operation in Puerto Rico and defining requirements for GFM inverters in Puerto Rico as additional requirements on top of the base requirements in IEEE 2800 Standard.
- Ensuring DERs robustness to voltage deviations will benefit system reliability. The IEEE Standard 1547 (IEEE 1547) (IEEE 2018b) Category III fault ride-through (FRT) settings proposed by LUMA should be followed to avoid unnecessary disconnections during and after transmission faults.
- Limiting the capacity of single generation and BESS utility-scale plants and single units, given the relative size of the system, will likely benefit reliability and resilience in the future. Establishing standards for maximum size of plants and units could be considered. Having future utility-scale generation and BESS spread in various locations can help with grid recovery (provided those resources can help with grid recovery – see also below considerations).
- The Puerto Rico grid would benefit from bringing new transmission, distribution, and generation (including both utility-scale and DER) infrastructure for all hazards, including hurricanes, up to new standards adopted in Puerto Rico after Hurricane Maria. Because the entirety of the infrastructure cannot be hardened immediately, it is important that Puerto Rico continues developing, updating, and implementing plans for managing legacy infrastructure over time.
- The Puerto Rico grid would benefit from changing the current paradigm to enable renewables (DERs and utility-scale) and storage to participate in grid recovery; GFM controls and black-start capability are required. Black-start capability from BESS at various locations would be very valuable for recovery processes. Pilot projects for BESS participation in black start could be developed in the short term. Developing pilot projects for solar and wind generation participation in black-starts and system recovery, in tandem with BESS, could be beneficial to reduce dependency on fossil fuel generation in system recovery. Researching and developing participation of DERs in system recovery from the distribution system could be beneficial for more efficient system recovery after large events utilizing all available resources.
- The Puerto Rico grid would benefit from deploying utility-scale battery energy storage in the near term to support bulk power system resilience to extreme weather events, as well as day-to-day reliability, if properly sized, sited, and fitted with GFM controls and black-start capability.

10.1 Background

Simulation of Puerto Rico's power system operation in Section 9 (page 241) revealed that significant expansion is needed in the 38-kV transmission network for future scenarios. However, that analysis is derived from approximated power flow modeling. This section describes how additional modeling approaches are used to capture the physics of power flows, voltage control, frequency control, and grid stability. We expect these aspects to be key in the near term as renewables significantly grow from the current levels. Therefore, this section emphasizes the study of near-term scenarios, out to 2028. We analyze the need for additional equipment and control system requirements to reliably operate the bulk power system (38 kV, 115 kV, and 230 kV) with high penetration of renewables. This section also covers resilience analysis of the bulk power system, focusing on system recovery simulations of 100 hurricane events.

Aggregated behaviors of DERs connected at the distribution grid are modeled, capturing their effects on the power flows, system dynamics, and recovery from extreme events.

Power electronics control and operations are key to maintain system stability, especially for high levels of renewable systems. Solar and wind generation as well as BESS are interfaced with the grid through power electronics-based converters, also called inverters. These converters transform DC electricity, in the case of solar generation and BESS, into AC electricity that the grid needs. In the case of wind generation, the converters allow the wind turbines to produce electricity while they rotate at a wide range of speeds. Controlling the power electronics inverters in these inverter-based resources (IBRs) is key for transitioning Puerto Rico's grid to 100% renewables.

This section discusses two main fundamental controls for IBRs that affect system stability. First, traditionally, IBRs connected to bulk power systems have used grid-following (GFL) inverters. Inverters with GFL controls need other resources to establish voltage and frequency before they can operate; simply put, GFL cannot function in isolation, they cannot be the only resources operating in the system; they need other resources to establish the voltage and frequency of the grid. The second type of control is the grid-forming (GFM) inverter control. GFM inverters can maintain stable voltage and frequency in power systems. GFM inverters can be the only source in a system. More importantly, GFM inverters can establish frequency and voltage in systems with large amounts of IBRs. It is important to also note that GFM inverters are not yet widespread in bulk power systems. Their use, capabilities, settings, and operation modes are not standardized yet.[133] GFM inverters have been used often in microgrids. Their widespread use in Puerto Rico would need to evolve, as is happening in other power systems in the world.

It is important to note that the power system must be stable at every moment of operation. The most challenging hours could be those where there are 100% IBRs in the system. These moments of 100% IBRs may happen in the short term, as soon as there are enough utility-scale and

[133] IEEE 2800-2022 Standard provides requirements for inverter-based resources (IBR) interconnection capabilities and performance criteria. However, the standard does not specifically provide requirements for GFM inverters and leaves to transmission operators the definition of context for application and needs for GFM inverters. On the other hand, IEEE 2800-2022 does provide requirements for IBRs that could be useful for GFM inverters, like the definition and performance requirements for fast frequency control, which can apply for both GFM and GFL inverters.

distributed IBRs at their peak of generation to cover the system load needs (e.g., around noon on a weekend with mild temperature). In this section, we focus on the 100% instantaneous IBR penetration, that is, when IBRs are 100% for some moments during operation.

We also conduct two types of analysis of two scenarios: 3LS (maximum DER adoption, less land availability, stress load projection) and 1LM (economic DER adoption, less land availability, mid case load projection). First, we study time-series of full power flow solutions (with both active power flows and reactive power flows/voltage support included in the models) to evaluate how variability from solar and wind generation can affect the voltage support needs hour by hour. Second, we simulate system recovery after hurricane events.

We organize this section into eight subsections covering different aspects of bulk power system impact analysis: (1) AC power flow analysis, (2) grid strength analysis, (3) model tuning, (4) stability analysis for very near term, (5) stability analysis for 100% instantaneous penetration, (6) load dynamics and DER modeling, (7) system black-start using grid-forming BESS, and (8) resilience analysis. Each of the eight subsections contains a description of methodologies, results, and considerations.

10.2 AC Power Flow Analysis

10.2.1 Voltage Support Analysis With Time-Series of Chronological AC Power Flow

In this section, we describe how we use the Pacific Northwest National Laboratory's (PNNL's) Chronological AC Power Flow Automated Generation (C-PAGE) tool to obtain a time-series of full power flow solutions and obtain reactive power compensation and voltage support needs in the transmission and subtransmission system that include voltage levels of 230 kV, 115 kV, and 38 kV.

Results of the analysis presented in this section show that significant reactive compensation equipment, mostly at the 38-kV network with one location at 115 kV, is needed for the scenarios with the highest (3LS) and lowest (1LM) levels of DER adoption. Results of the analysis presented here also show dynamic reactive power compensation is needed as the reactive power requirements change hour by hour. Renewables resources and energy storage located at the 38 and 115-kV systems may be able to provide part of this requirement depending on their locations. It is also important to note that overloads in transmission lines, such as those highlighted in Section 9.3.3 (page 260) and Section 9.3.4 (page 262), will need to be resolved before determining reactive power compensation needs. For the cases studied in this section, the 2028 scenarios, no overload was observed. Overloads could possibly be reduced by optimizing placement of generation and energy storage resources, reconductoring, and expanding transmission.

Production cost modeling (PCM) is a critical tool for power system planners to simulate unit commitment and dispatch of power system resources on an hourly basis. Few commercial solutions or open-source tools can manage entire interconnections with thousands of substations. For PR100, the National Renewable Energy Laboratory's (NREL's) Sienna tool[134] was used for

[134] "Energy Analysis: Sienna," NREL, https://www.nrel.gov/analysis/sienna.html

PCM as discussed in Section 9 (page 241). PCM tools, like Sienna, can use network representation and power flow approximation that capture only the active power flows and ignore reactive power flows and bus voltages; this is called DC power flow approximation.

Successfully feeding the PCM dispatch to full power flow models—that consider both active and reactive power flows and voltage profiles—is widely acknowledged as a difficult subject that has yet to be fully resolved. To properly feed the PCM dispatch to power flow models, the system topology between the PCM and power flow model must be consistent.

Because the PCM solves the optimization problem using a DC model and a linear solver in the first stage, bus voltages are not addressed in the solution. The system loss is another component that influences the solution. The loss in PCM is assessed and added to the load, but the loss in AC power flow is computed during the power flow solution. Furthermore, because reactive power load and generation are completely neglected in the PCM but fully considered in the AC power flow, assumptions regarding them must be made while solving the chronological power flow models. Finally, the allocation of area load to the bus level in PCM is fixed throughout the simulation period. The load distribution factors are generated once and then applied for all hours based on a reference power flow instance. Though this is possible in PCM because bus voltages are not taken into account, it is often not the case in the AC power flow model because bus load distribution and voltage profiles fluctuate significantly between seasons. All these elements combine to make importing and resolving the chronological AC power flow difficult. Creating a basic AC-converged power flow case normally takes a few hours to days because it involves PCM, AC convergence, and reactive power planning.

10.2.2 Methodology

To address this, PNNL developed the C-PAGE (Vyakaranam et al. 2021) for converting data sets between PCMs and power flow models and creating chronological AC power flow instances. The procedures were then automated, with options to offer results in multiple forms. The tools and techniques established are applicable to any big, interconnected system, such as the Western Electricity Coordinating Council (WECC), the Eastern Interconnection, and the Texas Electric Reliability Council. This effort also helps achieve national renewable targets and enhances system resilience by facilitating the connecting of new renewable energy.

10.2.2.1 DC-to-AC Convergence Process

The conversion of DC power flow from PCM findings to an AC-converged power flow case is described here. The approach begins with Step 1 in Figure 171, which updates the new PCM result to an AC-converged power flow case received from the previous time-step. This is done because the loading circumstances of two consecutive power flow instances are frequently close to each other; therefore, the voltage of the AC-converged power flow case in the prior time-step is a useful starting point for solving power flow in the new power flow case. Losses are not considered in the PCM model in this study.

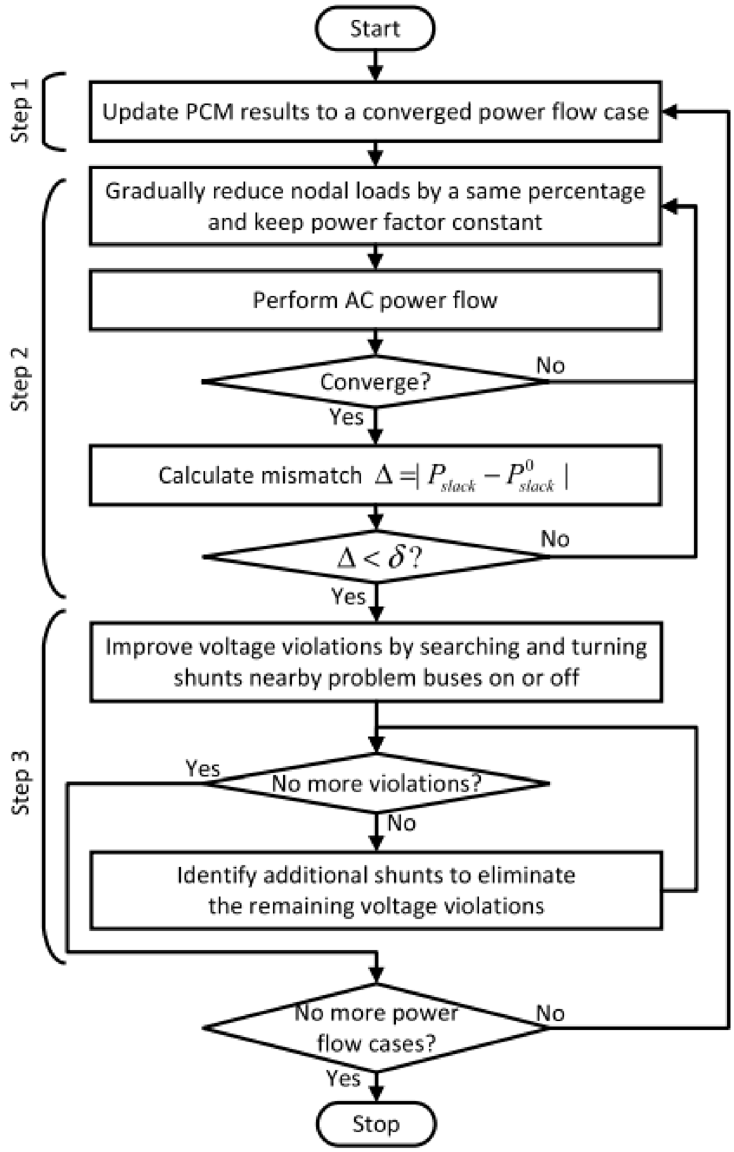


Figure 171. Proposed procedure to convert a DC-converged power flow case from PCM results to an AC-converged power flow case

Because PCM employs DC power flow, total generation equals total load in the new power flow condition. In this approach, the dispatch of all generation units, including the unit at the slack bus, is assumed to be fixed, as in PCM results. As a result, nodal loads must be lowered to account for transmission losses when converting DC-to-AC power flow scenarios. As a result, nodal loads are repeatedly lowered in Step 2 of the technique before AC power flow is initiated. If the power flow does not converge, the load is reduced even more.

If the power flow converges, the resulting real power generation at the slack bus is compared to the original value slack in the PCM result and the load is modified to keep the slack near the PCM. Following the achievement of an AC-converged power flow situation, the focus switches to optimizing the bus voltage profile. Improving voltage after establishing AC convergence is critical, because a good voltage profile at one time-step has a direct impact on the potential of achieving AC convergence in following time-steps. As a result, in Step 3, all bus voltages are inspected for voltage violations.

10.2.2.2 Reactive Power Planning to Improve Voltage Profile

To achieve reliability requirements under a wide range of practical contingencies, transmission planners must account for a sufficient supply of reactive power supplies. Reactive power is an important dependability service for the bulk power system. Transmission lines, generators, capacitors, and loads provide it. Transformers, loads, and transmission lines all use it. The relationship between reactive power and voltage magnitude is close. Maintaining voltage within a reasonable range is always crucial, and it is possible to do so with careful reactive power planning.

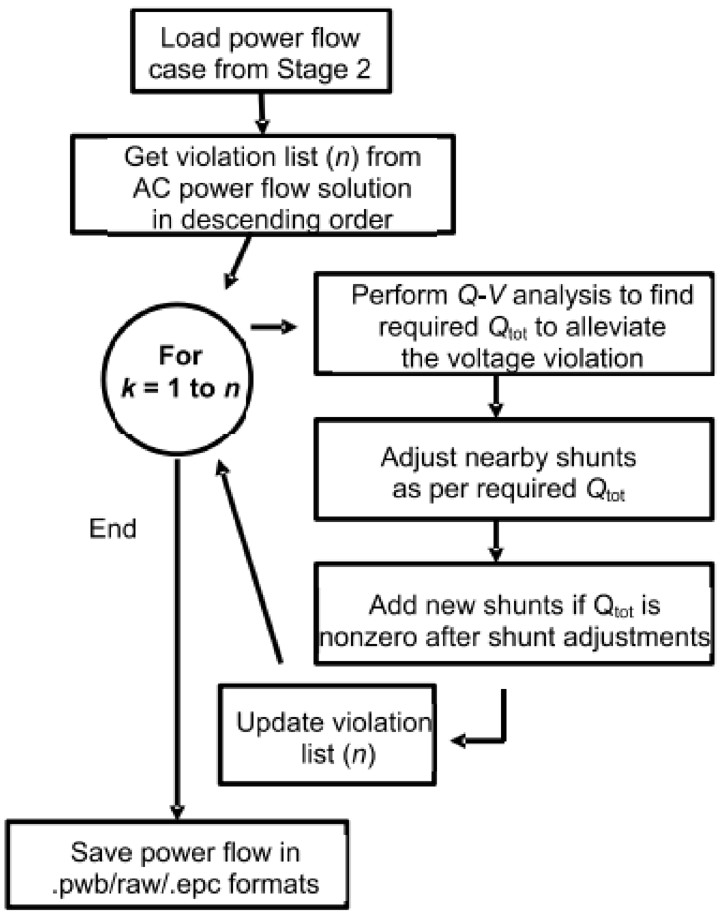


Figure 172. Reactive power planning to improve voltage profile

It is necessary to reduce the voltage profiles of each of the potential voltage violations in the convergent AC power flow case at Stage 2. This is accomplished by developing methods to perform Q-V analysis, which illustrates the sensitivity and volatility of bus voltages with respect to reactive power injections or absorptions. Here, as illustrated in Figure 172, the strategy is to gradually increase the voltage profile while using appropriate reactive power support devices.

To extract voltage-out-of-range violations for higher voltages, the reactive power planning algorithm first loads the power flow case from Stage 2. Initially, the algorithm arranges the list of violations according to decreasing voltage and it then applies Q-V analysis to the bus with the most violations; this allows for the determination of the necessary reactive power support (Qtot) to mitigate the voltage violation. Next, it looks for shunts close to the bus that has been violated the most. If any are found, it modifies the shunt reactive power device or devices in accordance with the necessary Qtot value and updates Qtot. It adds a new shunt if, after shunt adjustments, Qtot is not zero. After that, a violation list is extracted, and the power flow is solved. A bus is skipped in this process if the simulator cannot converge at a specific transfer level; if not, this procedure is repeated until the violation list is empty. This method gradually enhances the voltage profile and, when combined with suitable reactive power support devices, may partially address flow violations.

Generation redispatch has the potential to reduce flow violations, but it has not been used because we want to maintain the PCM generation dispatch at all times. Ultimately, it stores the power flow case with the improved voltage profile in formats like PSS/E's.raw, PowerWorld's.pwb, and PSLF's.epc.

10.2.3 Results

Voltage violations are lowered or avoided in this stage by utilizing existing and new shunts. Only buses with rated voltages higher than 15 kV are checked and resolved, because increasing voltage on buses with lower voltage ratings is less beneficial. The permissible voltage range in this investigation is 0.9–1.10 pu. Furthermore, a bus is deemed to have voltage violation if the voltage magnitude on the bus is outside the range of 0.90–1.10 pu.

As indicated in Table 34, after obtaining the AC power flow convergence from Step 2, Bus A and Bus D are recognized as having overvoltage, but Bus B and Bus C have undervoltage.

Table 34. Example of Voltage Violations at Hour 5,170 and How Shunts Eliminate Them

Stage	Bus	Rated Voltage (kV)	Voltage (pu)	Required Reactive Power (Mvar)	Total Violations
1	Bus A	38.0	1.10474007	-4.5592538928	1
2	Bus B	115	0.86100722	33.3537037037	111
3	Bus C	23.0	0.88920528	36.8569135802	5
4	Bus D	38.0	1.10030032	-1.10036008976	2

In Stage 1, a Q-V analysis is performed on Bus A, which has the largest voltage violation. According to Table 34, 4.5592538928 Mvar must be absorbed at this bus to drop the voltage from 1.10474007 pu to 1.08651 pu. As seen in Figure 171 and Figure 172, the algorithm looks for nearby shunts, but no shunts are accessible near this bus. As a result, an additional shunt inductor with a rating of 4.5592538928 Mvar is added to this bus, as illustrated in Table 34.

Power flow is restored at Stage 2, indicating the overvoltage problem has been totally handled with the additional shunt at Bus A. However, the undervoltage issue at Bus B persists. A Q-V analysis is performed, and it is determined that 33.3537037037 Mvar must be injected into the system at this bus to correct the voltage violation as no shunts are available at this bus or numerous surrounding buses. Based on the state of the shunts at these sites, the reactive power injected at this bus is 33.3537037037 Mvar. Figure 173 depicts the minimum and highest voltages at all buses with rating voltages of all buses at hour 5,170 results. Significant undervoltage violations are observed in the AC-converged power flow scenarios produced after Step 2 in Figure 172 (i.e., before shunts are added or adjusted). Such voltage violations, however, are eliminated if existing switched shunts are adjusted and additional shunts are introduced to the system.

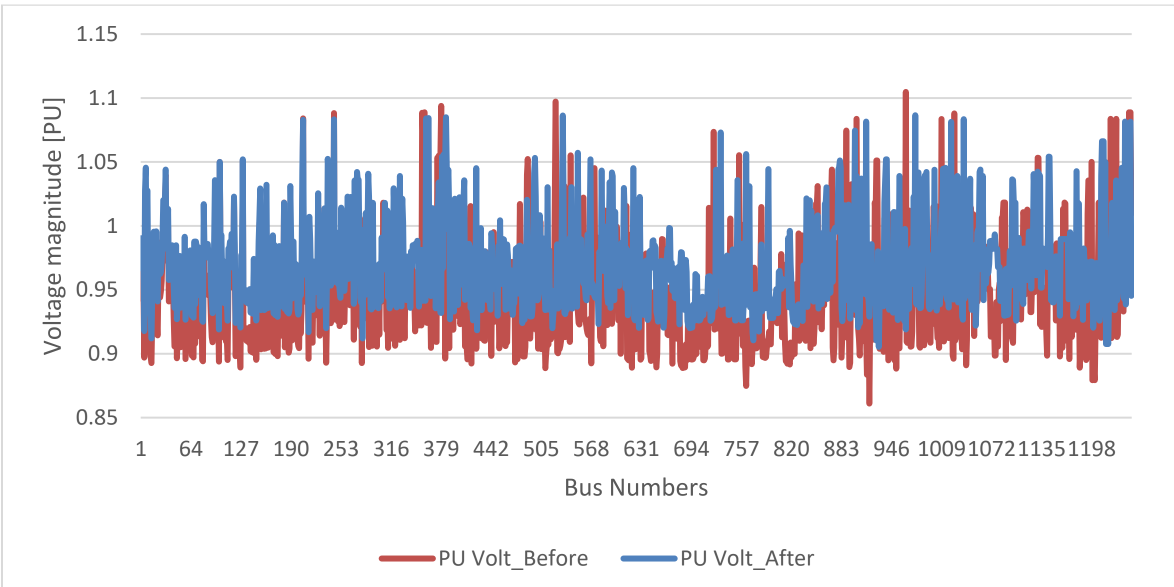


Figure 173. Minimum and maximum bus voltages for hour 5,170

The reactive power compensation is needed to bring the system within acceptable limits as illustrated in Figure 173. Figure 174 shows the capacitive reactive power compensation needed to resolve low-voltage violations at two specific locations. Figure 175 shows the inductive reactive power compensation needs to resolve high-voltage violations at two specific locations. Because reactive power needs to change hour by hour, dynamic compensation equipment will be needed.

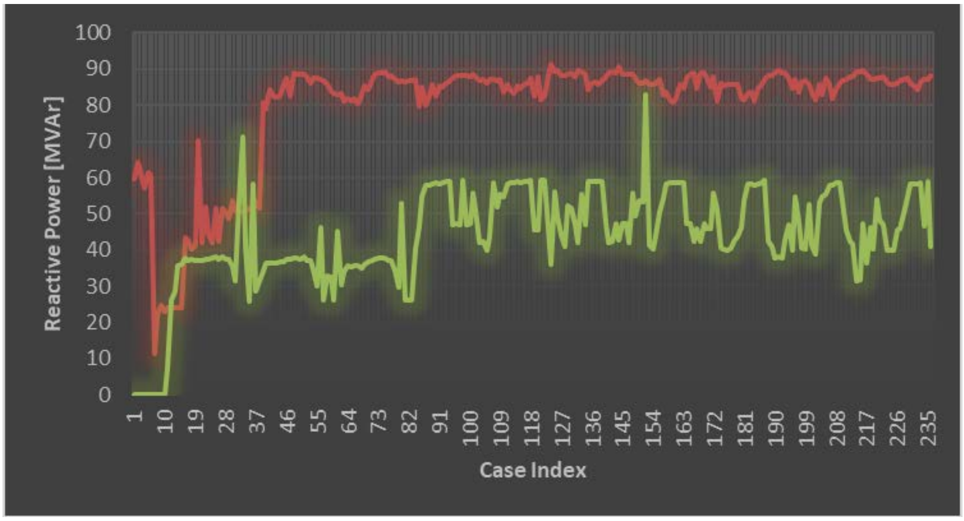


Figure 174. Capacitive reactive compensation needs, at two locations (green and red curves), for each hour of one week of August 2028, 3LS scenario

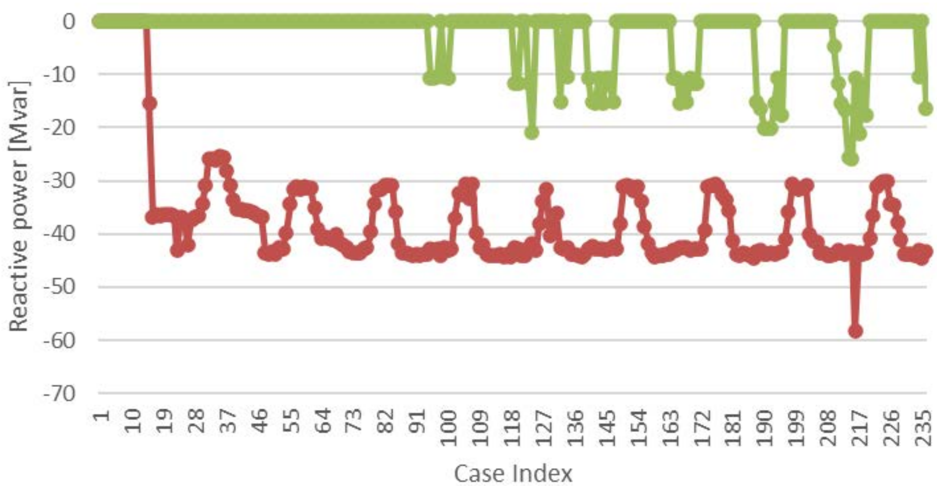


Figure 175. Inductive reactive compensation needs, at two locations (green and red curves), for each hour of one week of August 2028, 3LS scenario

Figure 176 and Figure 177 show reactive power compensation needs for the full system, hour by hour, and the figures show totals for reactive (Q_+) and inductive (Q_-) compensation needs. Voltage support equipment needed for transmission and subtransmission reliability is for a total of about 1,200 Mvar for the 3LS 2028 cases analyzed.

Solar plants and batteries connected to 38-kV and 115-kV systems could meet part of this requirement if they were located where voltage support was needed. And as mentioned before, line overloads should be resolved before voltage support equipment is designed.

Figure 176. Reactive compensation needs, sum for all locations, for each hour for 3LS 2028, for one week of January

Figure 177. Reactive compensation needs, sum for all locations, for each hour for 3LS 2028, for one week of August

10.2.4 Considerations from AC Power Flow Analysis

Additional voltage control equipment is required, mainly in the 38-kV subtransmission network, to accommodate the growth in distributed and utility-scale renewable generation. Renewable generation and energy storage could provide part of this voltage control requirement. The following considerations are provided regarding AC power flow analysis:

- Performing additional studies should include exhaustive contingency analysis, like North American Electric Reliability Corporation (NERC) TPL standards do.

- Planning for additional voltage support equipment for transmission and subtransmission reliability should also utilize voltage support from all renewables and energy storage at both utility-scale and DER levels.
- Planning can ensure a portion of voltage control equipment is dynamic to deal with voltage fluctuations from hour to hour at 38 kV. Dynamic voltage control equipment includes technologies like STATCOM, SVC, and synchronous condensers. On the other hand, less expensive equipment, like fixed and switched capacitors and reactors, cannot follow voltage fluctuations as efficiently.

10.3 Grid Strength Analysis

The strength of a grid refers to the voltage stiffness following a fault disturbance. Strong grids can withstand fault disturbances to a higher degree and prevent widespread voltage impacts. With increasing penetration of IBRs on the Puerto Rico grid, their presence will become more dominant than synchronous machines and fault current availability will decrease, impacting voltage stability and overall grid strength. Typically, synchronous generators can provide 5.0×–10.0× their rated current capacity in fault current while IBR might only provide 1.0×–1.3× rated current (Lin et al. 2020; Choi et al. 2022). In systems dominated by traditional synchronous machines, short circuit current levels are much higher and the protection system has been tuned for these conditions. Additionally, with the dwindling fault current available in a high IBR grid, voltage instability issues may become more prevalent, leading to more impacts from disturbances than previously seen. Weak grid issues can take the form of voltage instability, harmonic resonance, and FIDVR (Kundur 1994, 112). Grid strength assessments can provide an indicator for which locations might be more susceptible to weak grid issues and which locations could be candidates in which to place compensation devices.

10.3.1 Methodology

Short Circuit Analysis: To assess grid strength, a three-phase bus fault is applied at every bus in the system to quantify short circuit capacity and current contributions from generators. The fault analysis conditions are based on International Electrotechnical Commission, or IEC, Standard 60909 calculations, which is applicable for buses with nominal voltage less than 550 kV (Metz-Noblat, Dumas, and Poulain 2005); 230 kV is the highest voltage level in the Puerto Rico grid.

Calculation Method for Change in Short Circuit MVA (SCMVA): Several metrics are considered to assess the change in grid strength from a 40% renewable, 60% traditional generation base case to a 100% renewable case with high penetration of IBRs. One metric to evaluate is the change in short circuit apparent power capacity at the bus level, which is calculated using the following percentage change formula:

$$\Delta SCMVA = \frac{SCMVA_{100} - SCMVA_{40}}{SCMVA_{40}} \times 100$$

where the $SCMVA_{100}$ is the short circuit capacity of one bus in the 100% renewable scenario and $SCMVA_{40}$ is the short circuit capacity of the same bus in the 40% renewable base case.

Electrical Distance Calculation: To determine the current contribution based on the electrical distance, the bus impedance matrix is needed. The electrical distance between any bus i and j is calculated based on:

$$D_{ij} = Zbus_{ii} + Zbus_{jj} - 2Zbus_{ij}$$

where Zbus is the bus impedance matrix found by inversion of the admittance matrix and the subscripts correspond to row and column index (Peng et al. 2019).

Short Circuit Ratio Metrics: The short circuit ratio (SCR) metric attempts to quantify the stiffness of bus voltage to changes in power fluctuations. Several methods exist for calculating the ratios under various assumptions. However, all the metrics considered in this study assume the short circuit capacity at the bus does not include contributions from any IBR. The traditional SCR method accounts for the short circuit apparent power capacity available at the bus prior to any IBR connections to the additional megawatts of capacity that are being installed at bus i.

$$SCR_i = \frac{SCMVA_i}{MW_i}$$

Systems with high SCRs (greater than 5) are considered stiff or strong systems because bus voltage is not as susceptible to disturbances. A lower SCR indicates a larger change in field current to maintain constant terminal voltage for a load change (Kundur 1994, 112). The rule of thumb for a system to be considered weak is an SCR below 3 (Choi et al. 2022; Kundur 1994). The traditional SCR metric is best used for single IBR interconnections in a synchronous generator dominant system (Choi et al. 2022; NERC 2017).

To assess the interactions among multiple IBR resources, the equivalent circuit-based short circuit ratio (ESCR) can be more meaningful. The ESCR, which is synonymous with the SCR with interaction factors method (NERC 2017):

$$ESCR_i = \frac{SCMVA_i}{MW_i + \sum IF_{ij} \times MW_j}$$

where the interaction factor, IF_{ij} is defined as:

$$IF_{ij} = \frac{\Delta V_i}{\Delta V_j}$$

and the change in voltage is determined by injecting negative 1 Mvar load at bus j and observing the change in voltage at bus i (the IBR bus under study) and bus j (the other IBR buses in the case) using the power flow solution. The SCMVA at bus i used in the equation for SCR does not consider contributions from any of the IBR. Interaction factors are calculated for all other IBR buses and multiplied by their respective capacity.

In contrast to the SCR and ESCR, the weighted short circuit ratio (WSCR) is a regional metric where IBR are considered to be fully interacting within a defined region as specified by:

$$WSCR = \frac{\sum_i^N SCMVA_i \times MW_i}{(\sum_i^N MW_i)^2}$$

where N is the region of buses within close electrical distance to the fault at bus i.

10.3.2 Data Input and Assumptions

100% Conventional Powerflow: A power flow case supplied entirely by synchronous generation is representative of the grid in recent years. The case includes 17 synchronous generators. The case used for the study is only an approximation of the historical system and does not reflect the availability of today's generation mix.

60% Conventional, 40% Renewable Powerflow: The 40% renewable case includes Tranche 1 planned renewable installations that are assumed to provide 1.2 pu fault current, and thus, the machine reactance is modified to 0.917. Also, the machine MVA is modified to be 1.2× the maximum power rating.

100% Renewable Powerflow: The future scenario assumes 100% instantaneous renewable IBR generation from Tranche 1 and Tranche 2, and all remaining synchronous generation is retired. In this scenario, we assume (1) Tranche 1 and 2 renewables can provide 120% rated fault current and (2) no IBRs connected to the distribution level provide fault current, though this assumption may be revisited in the future as grid codes change. This includes single-phase and three-phase DERs on the distribution system and preexisting renewable installations, which may not necessarily be upgraded with advanced inverter technology in the future.

Substation Locations: GPS coordinate locations of the substations developed by the PR100 project team are used to visualize the locations of SCMVA and buses. Though the coordinates are believed to be reasonably accurate, locations should be considered approximations.

Synchronous Condenser Placement: Synchronous condensers are one option to meet the challenges of weak grid conditions because they provide the same fault current levels as rotating generators. Synchronous condensers are modeled as synchronous generators with no active power output. To evaluate their impact on local SCMVA, synchronous condensers are placed in hypothetical locations throughout Puerto Rico in two scenarios, as shown in Figure 178. The first scenario assumes preexisting power plant machines could be suitable locations for synchronous condensers because of the infrastructure in place. The second scenario considers the low circuit impedance of high-voltage transmission substations to be advantageous locations for increasing the effectiveness of the synchronous condensers. In both scenarios for compensation placement, we assume the synchronous condenser provides 7.3× rated current and we conduct a sensitivity study on the capacity size needed to bring the 100% renewable case grid strength to similar levels as the 40% renewable case.

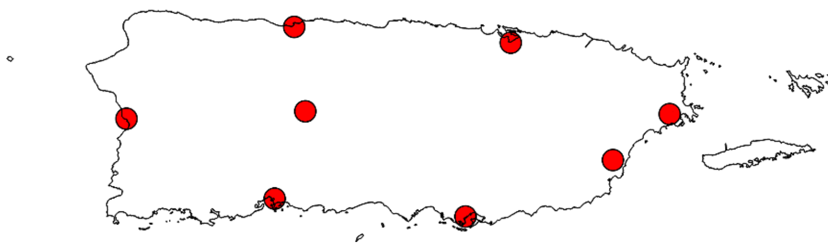


Figure 178. Approximate locations of synchronous condensers

10.3.3 Results

10.3.3.1 Fault Current Contribution Based on Electrical Distance

The fault current contributions from generators farther away from the fault location will be significantly less than that of generators nearer the fault. The difference in contributions is assessed by applying a fault at each bus location and tracing the initial symmetrical fault current from each generator. The results in Figure 179 and Figure 180 are the aggregated short circuit current for all fault contingencies studied on the system to each generator. The results indicate that the short circuit current exponentially decreases with longer distances to the fault. We can also deduce that generators farther than 1.1 pu impedance away will not contribute meaningful amounts of short circuit current to the fault and should consider this value as a threshold for generator interactions. Therefore, it is important to consider the impact generator locations may have on the protection system in order to provide adequate short circuit current across Puerto Rico in a 100% renewable case.

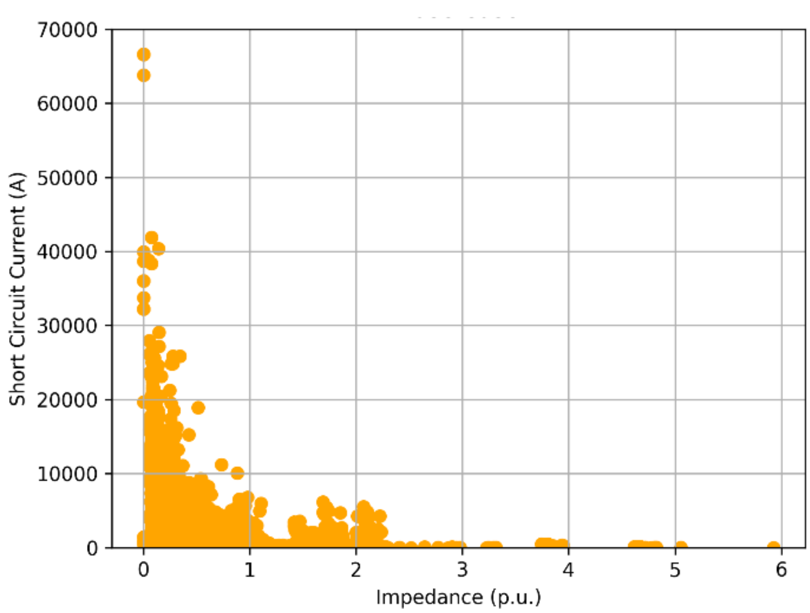


Figure 179. 100% Conventional case fault current contribution of all generators

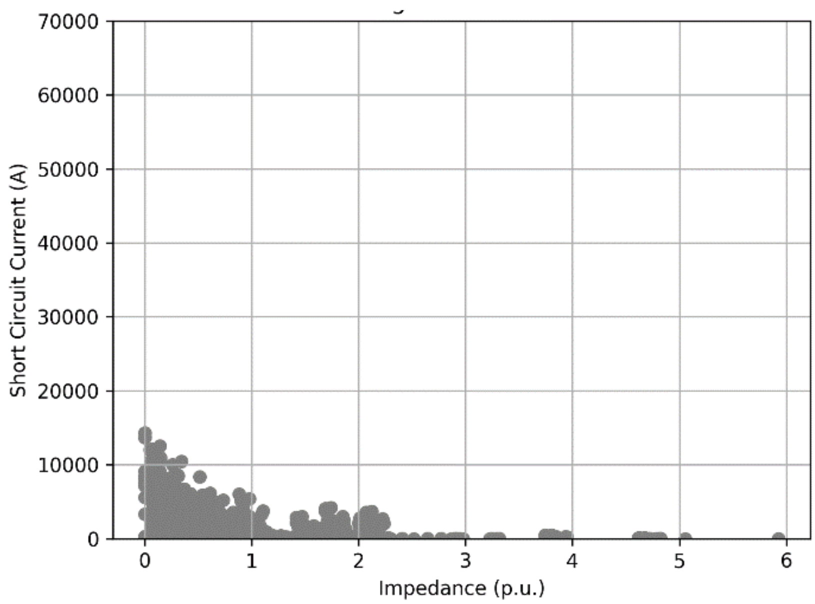


Figure 180. 100% Renewable case fault current contribution of all generators

10.3.3.2 Short Circuit Ratio Metrics for Tranche 1

The results for the traditional SCR, shown in Figure 181, indicate that the system is still strong for all proposed projects in Tranche 1 and minimum SCR is 8.19. However, the drawback of using the traditional SCR is that it does not account for the interactions among multiple IBRs being installed. The results for ESCR, shown in Figure 182, are much more conservative than the SCR metric and indicate 4 of the 16 IBR installation locations might result in a weak grid (ESCR < 3). Additionally, if applying the WSCR method with a regional boundary of 1.1 pu impedance determined from the current contribution study, Tranche 1 all IBRs are considered to be within the same local region N and this results in a WSCR of 1.947. As the results in Table 35 show, the three metrics produce vastly different results, where the SCR potentially overestimates grid strength by not considering nearby IBR interactions and the WSCR conceals individual location strength by considering all IBR installations as one region. However, these results provide only a high-level overview of potential grid strength impacts and detailed study is required, particularly at locations with low ESCR, which includes inverter manufacturer information and installation-specific settings.

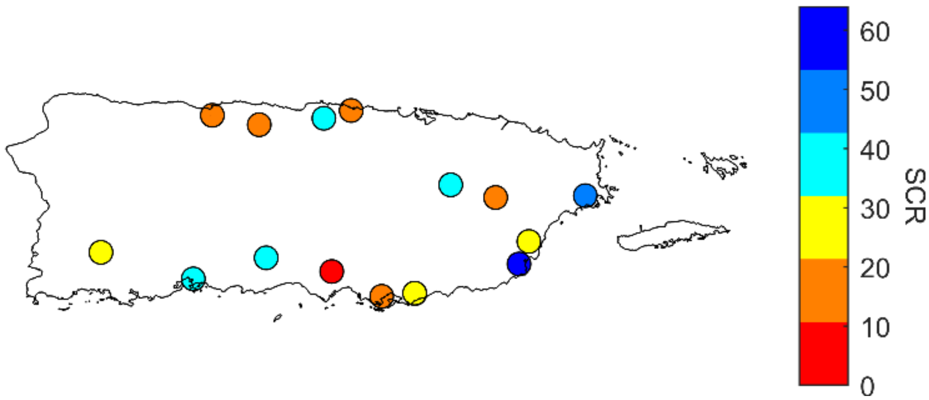


Figure 181. SCR of Tranche 1

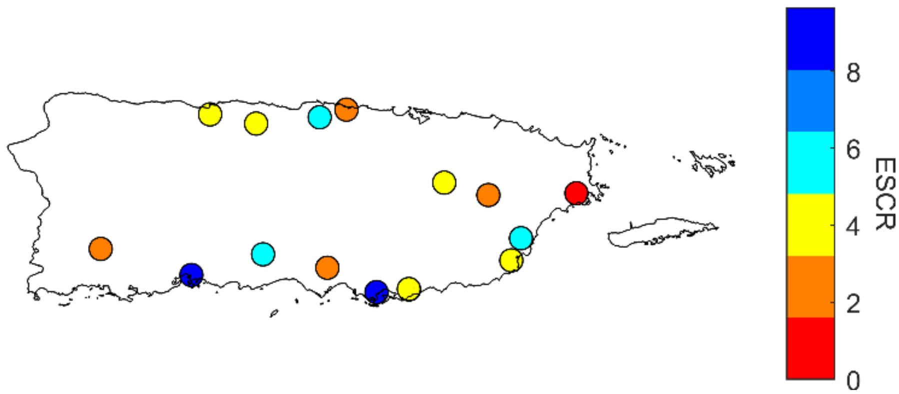


Figure 182. ESCR of Tranche 1

Table 35. Comparison of SCR Metrics

Location	SCR	ESCR
Santa Isabel	8.19	2.43
Breñas	12.30	1.74
Aguirre	12.71	8.10
Juncos	15.61	3.08
Jobos	16.66	3.96
Barceloneta	16.90	3.71
Cambalache	20.41	4.55
Jobos	23.33	3.74
Yabucoa	26.19	5.41
San German	29.75	2.58
Bairoa	34.23	4.31
Juana Diaz	39.18	5.13
Costa Sur	39.79	9.63
Vega Baja	40.62	5.79
Daguao	46.77	1.49
Yabucoa	63.94	3.22
Regional Metric	**WSCR**	
All Locations	1.947	

10.3.3.3 Change in Short Circuit Capacity

The change in SCMVA of the entire system when comparing the 40% renewable case and the 100% renewable case is shown in Figure 183. The highest decrease in short circuit capacity is seen at generator locations followed by the 115-kV and 230-kV buses which can be seen in Figure 184 and Figure 185. Because the high-voltage transmission system has the lowest circuit impedance, it carries most of the short circuit current and thus the transmission system loses a greater portion of the short circuit capacity. The 38-kV and lower voltage locations do not indicate significant change in SCMVA because they have less available capacity in both cases because of their higher circuit impedance to generation sources. Locations with low SCMVA can be seen in rural mountainous regions like the Adjuntas region as well as grid edge areas such as the islands of Vieques and Culebra.

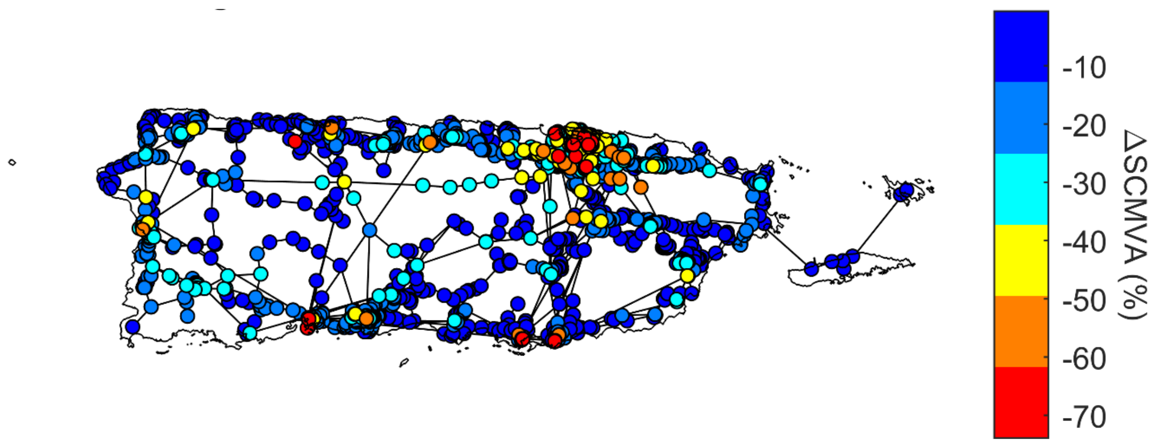


Figure 183. Change in short circuit capacity system-wide

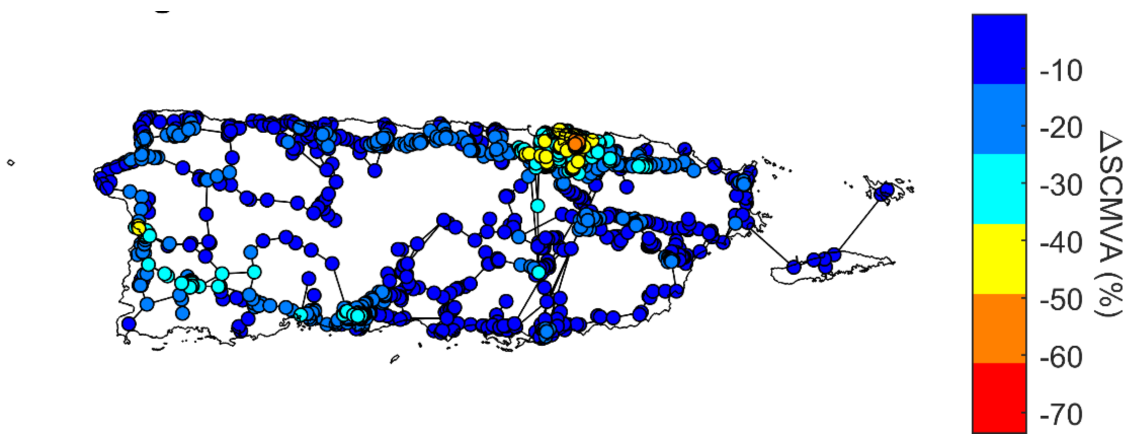


Figure 184. Change in short circuit capacity 38-kV system

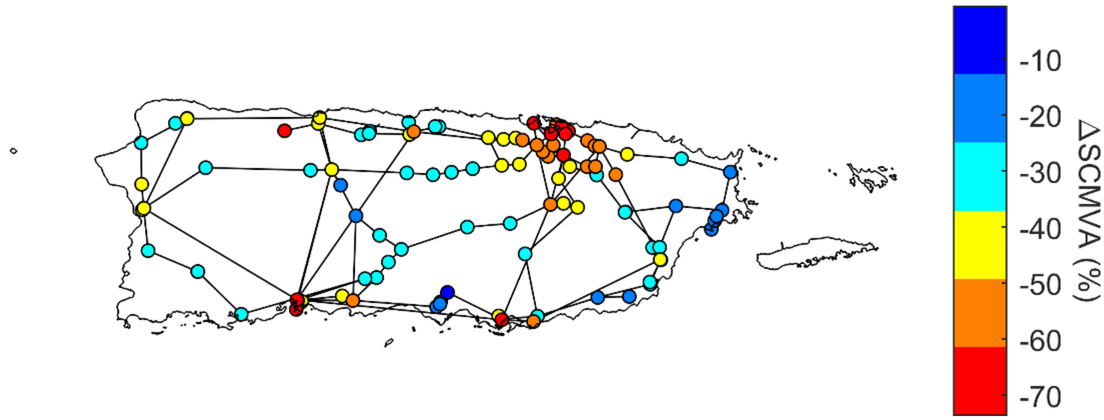


Figure 185. Change in short circuit capacity high-voltage system

10.3.3.4 Synchronous Condenser Locations and Capacity

To strengthen the 100% renewable case to the short circuit capacity level in the 40% renewable base case, synchronous condensers are placed throughout Puerto Rico at eight locations considering two scenarios: (1) they are placed at existing plant locations as that may be most suitable due to infrastructure availability or (2) they are placed at the transmission substation so the impedance distance to the high-voltage transmission system is reduced. See Figure 178 for the approximate locations of the condensers.

A sensitivity study is performed on the required capacity of the condensers at each location to observe the approximate levels required for returning to base case strength. The sensitivity study results in Figure 186 indicate that placing the synchronous condensers at the transmission system would require approximately 200 MVA at each of the eight locations (1,600 MVA total) to bring the grid strength of 100% renewables up to levels similar to that of 40% renewables. By comparison, if synchronous condensers are placed at existing plant locations, 500 MVA at each of the eight locations (4,000 MVA total) could be needed to strengthen the grid to the base case. Therefore, the transmission system could be a more effective location for compensation devices and would require less capacity to strengthen the grid. The full study results can be seen in Figure 187 and Figure 188.

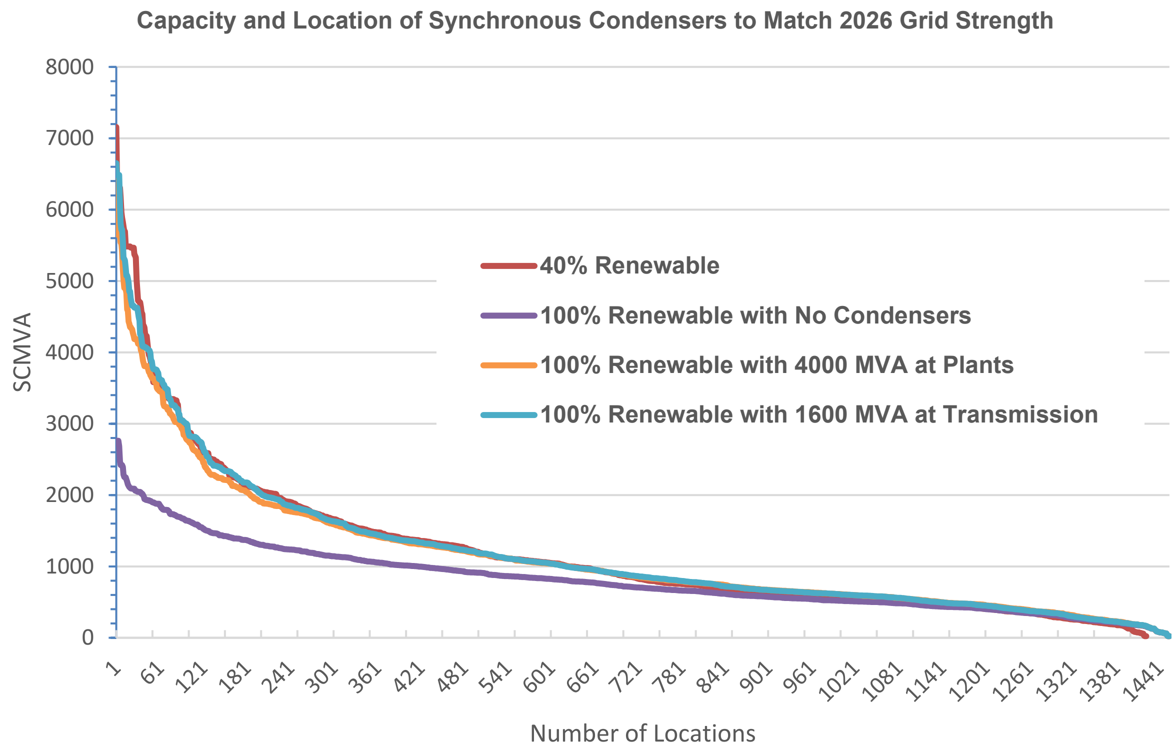


Figure 186. Synchronous condenser sensitivity study results

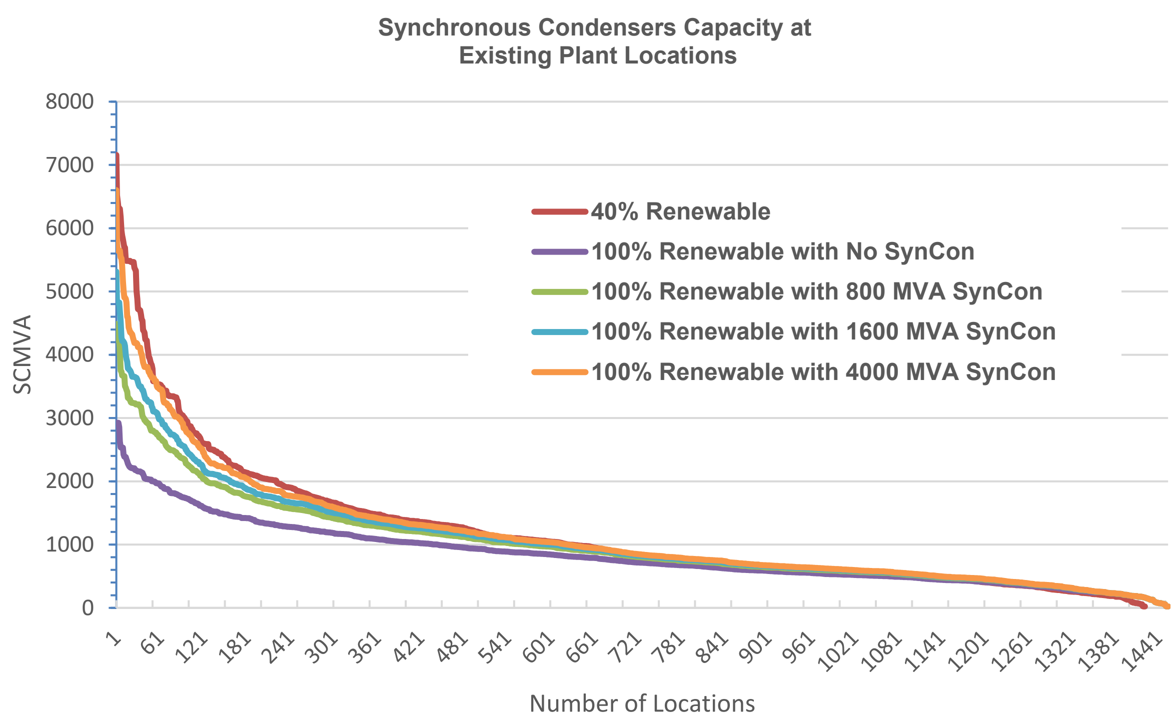


Figure 187. Synchronous condenser sensitivity at existing plants

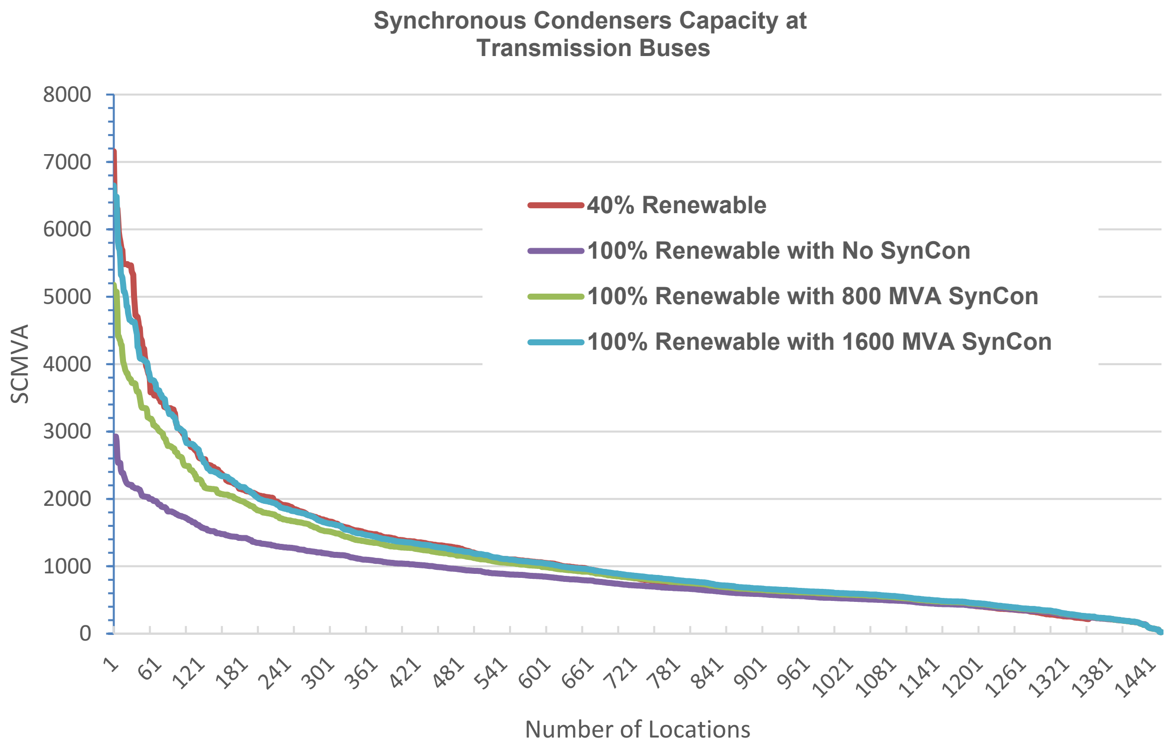


Figure 188. Synchronous condenser sensitivity at transmission

10.3.3.5 Short Circuit Capacity for Critical Contingencies

For the 100% renewable case, the short circuit capacity for critical *N*-1/*N*-2 contingencies corresponding to each point of interconnection (POI) is analyzed. For each POI bus, we identify the top two branches whose disconnections will cause the largest reductions in system strength without leading to an islanding condition at the POI. For SCR analysis, NREL developed an Automated System-wide Strength Evaluation Tool (ASSET) that can identify critical branches corresponding to each POI and can further compute the SCR corresponding to those cases (Sharma et al. 2023). Note that the critical branches identified by ASSET can be different from those used for the real-time contingency analysis applied in the NERC Standard TOP-001-3 (NERC n.d.). Through this process, an SCR change is observed for all major POIs, as shown Figure 189. Thus, identified contingency scenarios with highest SCR drop or an SCR below the threshold is further considered for detailed electromagnetic transient (EMT) studies.

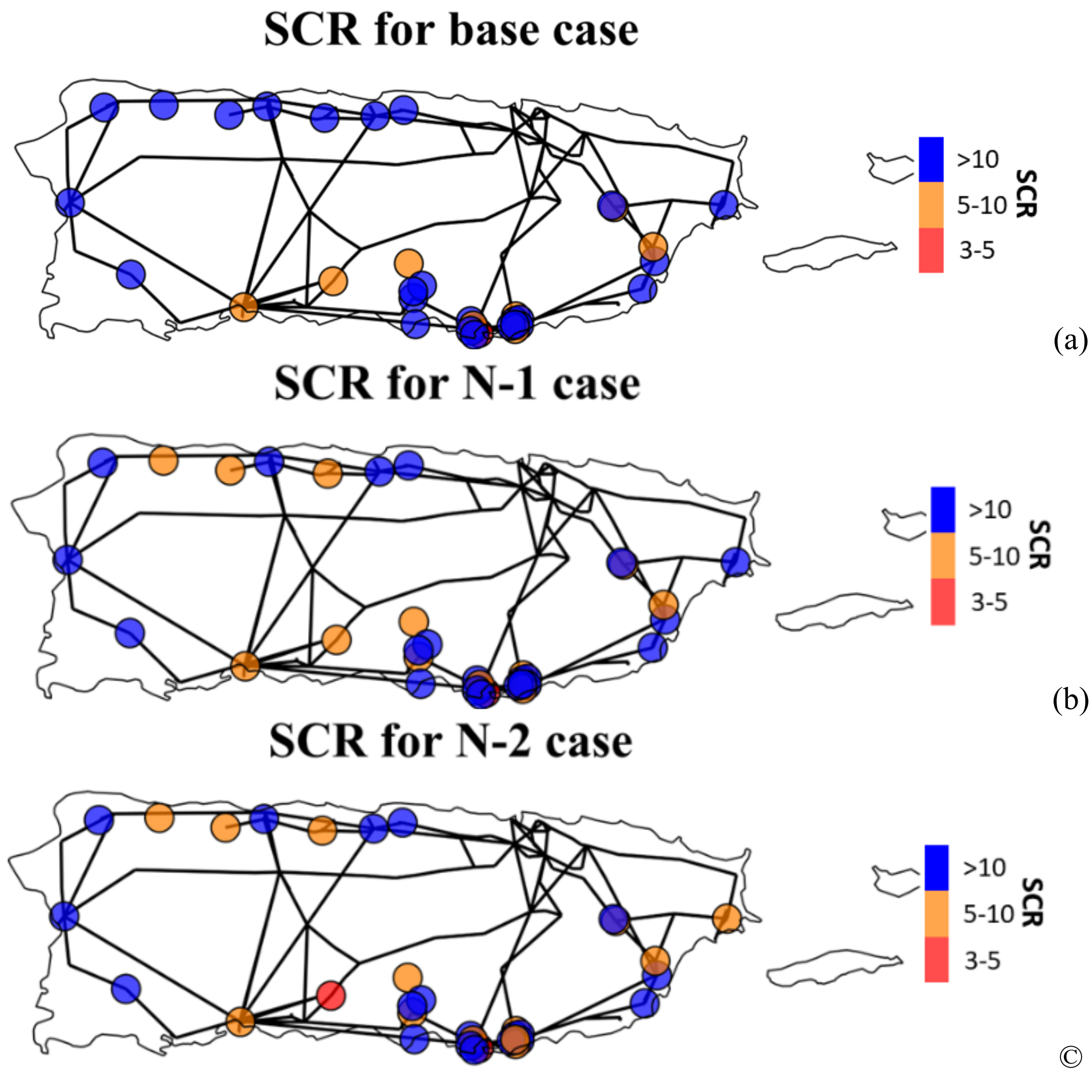


Figure 189. SCR for 100% renewable case (a) without any contingencies (b) for most critical line contingency (N-1) corresponding to each POI (c) for second-most critical line contingencies (N-2) corresponding to each POI

10.3.4 Conclusion from Grid Strength Analysis

Short circuit levels decrease in a high IBR case, potentially leading to the need to adjust existing protection settings accordingly because the current protection approach is unlikely to offer dependability and security under this future high IBR scenario. Detailed analysis of the protection system will be needed to determine the need to tune settings. System investments such as synchronous condensers or other technologies could be needed to ensure stable voltage across the system. However, further analysis is required that considers other constraints such as cost and location suitability for optimally sizing and placing synchronous condensers.

10.3.4.1 Considerations

Considerations for this section include that Puerto Rico implementers:

1. Assess existing protection systems, which may not operate with the lower available fault current, for a high inverter-based generation portfolio.

2. Perform a detailed study for weak grid locations to assess other factors that could impact voltage stability.
3. Place synchronous condensers at high-voltage substations (115 kV +) would allow for wider short circuit improvement because of the low circuit impedance. However, considering cost constraints is needed to evaluate if these locations are reasonable.
4. Add studies to support protection system upgrades and coordination to tolerate reductions in grid strength.
5. Ensure machine modeling accuracy to increase confidence in studying short circuit capacity. Areas where attention should be focused is the modeling of:
    A. Machine bases
    B. Machine source impedance
    C. Transformer impedances.

10.3.4.2 Future Work for Grid Strength

Although grid strength is an important metric and indicator of potential voltage stability issues, many other factors can cause voltage instability, such as transmission constraints, generator and IBR reactive power limits, load characteristics, and controls of reactive compensation devices. All these factors, in combination with grid strength impacts, will require a future comprehensive stability analysis for all tranches and future scenarios.

Additional compensation devices in the Puerto Rico grid should be evaluated and compared because cost is a significant driver of technology selection, and an accurate assessment of their benefits and drawbacks is needed to weigh the cost. Technology options to consider in a future study include a STATCOM, storage, and synchronous condensers.

10.4 Model Tuning

The power grid model must accurately represent real-world conditions; otherwise, the true vulnerability of the grid may be drastically overestimated or underestimated. Though power grid models represent only a snapshot in time, generator models should represent the physical equipment installed in the field to build confidence in engineers that the model and its simulations are reasonably accurate. Validation of the models could be done through in-field evaluations and would yield the most accurate assessment; however, this process is time-consuming and expensive. Another method to tune models is to rely on field measurements and compare them with simulations, but doing so requires data and background information and ultimately, and any modifications will be approximations because there is always some error in the model. Because of costs in labor and time and the availability of data, the tuning process is conducted in this task using measurement data of grid disturbance events. Our focus is tuning the frequency response of the model because it is one of the most critical parts of the model.

10.4.1 Methodology (Power Flow Modification)

The power grid model's frequency dynamic response is primarily influenced by generator governors and inertia. Their accuracy can be assessed by simulating real historical events that caused large frequency disturbances in the grid, such as the sudden tripping of generators. The base case power flow generation is adjusted based on the dispatch in the measurements at the time of each event; however, load data could not be provided. Therefore, the load is scaled to create a balanced case according to:

$$ScalingValue = \left(\frac{Total\ Event\ Generation}{Base\ Case\ Generation} - 1\right) \times 100$$

Using this method to scale the load means voltage throughout the system will not match the conditions during the event. Because the focus is on validating frequency, which is heavily influenced by overall load and generation balance, the voltage distribution will not impact the frequency response characteristics. When the power flow is solved for the new generation dispatch, the reactive power will be adjusted accordingly while active power will remain at the set values of the event.

10.4.2 Data Input and Assumptions

The power flow snapshot provided by LUMA is the basis for validation of generator governor parameters. The model contains primarily synchronous machines with few renewable resources. Two second-generation data were provided by LUMA for events detected from July 2021 to February 2022. Of these events, only three generation trips ranging from approximately 30 MW, 200 MW, and 450 MW could be identified clearly in the data. The larger two events are selected for validation events because they will show significant governor response. Generation active power measurement data were manually matched to the generator locations in the Power System Simulator for Engineering (PSSE) grid model. In the case when a match could not be obtained, the data are not considered in the validation process.

Frequency measurements are also needed to validate the generator governor response. Frequency measurements are provided by LUMA at 2-s intervals. Frequency is also available from the frequency monitoring network (FNET) GridEye system from the University of Tennessee, Knoxville, which records frequency and voltage at the distribution voltage level (Zhu et al. 2020). Because very few locations are available for FNET GridEye frequency disturbance recorders, the voltage profile is not used for tuning. However, the frequency can be considered a system's vital sign and is not as localized as the voltage. Frequency is constantly changing with any imbalance in load and generation and the frequency at the start of the event is likely not at nominal 60 Hz. However, simulation models always attempt to regulate the frequency to 60 Hz and therefore, there will be a mismatch in the starting frequency of the event. So, any tuned governor parameters in the simulation are approximations and serve as an indicator of which generators require detailed in-field evaluations to improve the model. This tuning process relies on large events so that the frequency excursion will undoubtedly have triggered significant governor response that will have a more dominant impact than the error in starting frequency.

10.4.3 Results

Simulations of the events show that a group of generator governors in the model are providing support for grid frequency, while the measurement data indicated the contrary. Additionally, the generator governors that did provide support during the actual events show a more aggressive support in the simulation. Therefore, the grid model is tuned by (1) turning off some governors in the model and (2) adjusting the deadband and droop parameters of governors that did respond during the actual event.

For the 200-MW event, a single generator tripped offline while providing approximately 10% of the total generation. The event caused a significant decrease in frequency but not enough to trigger under-frequency load shedding. Once the generator governors are tuned or disabled at appropriate generators, the tuned case shows a close approximation of the nadir compared to the base case as well as a good approximation of the rebounded frequency, as shown in Figure 190.

The second event, shown in Figure 191, is used to tune a 450-MW generation trip event, which was approximately 20% of the total generation. This event resulted in an automatic load shed action to recover the grid frequency because of under-frequency conditions. Because load measurements could not be provided for this event, an approximation of the load is shed, based on the simulation results and thus the overshoot of frequency after the load shedding takes place cannot be properly validated. The same governor settings that were tuned in the first event are applied in the 200-MW event, and doing so increases the confidence of the parameters selected and results in good overall governor response of the model.

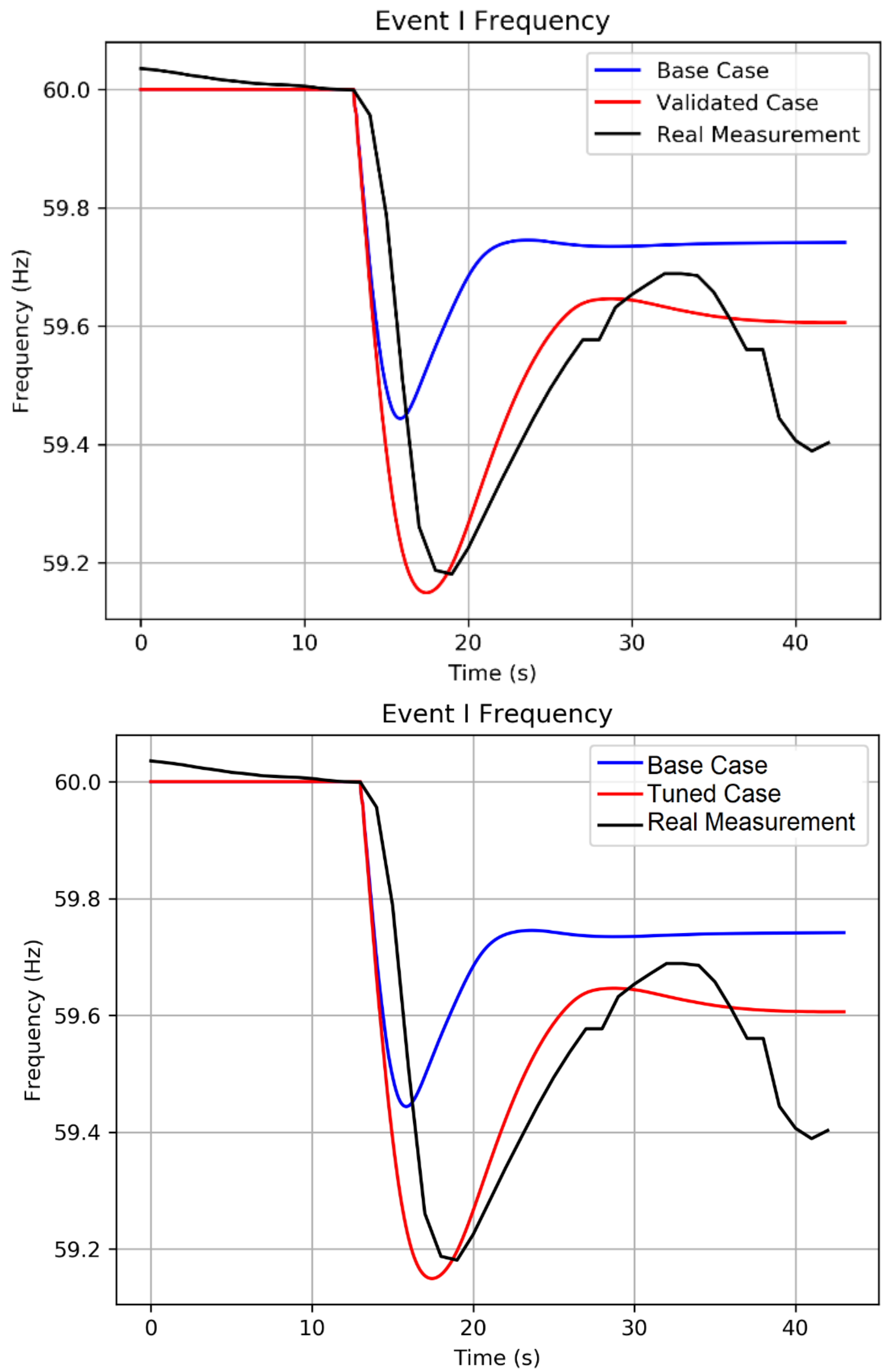


Figure 190. December 2021 event for model tuning

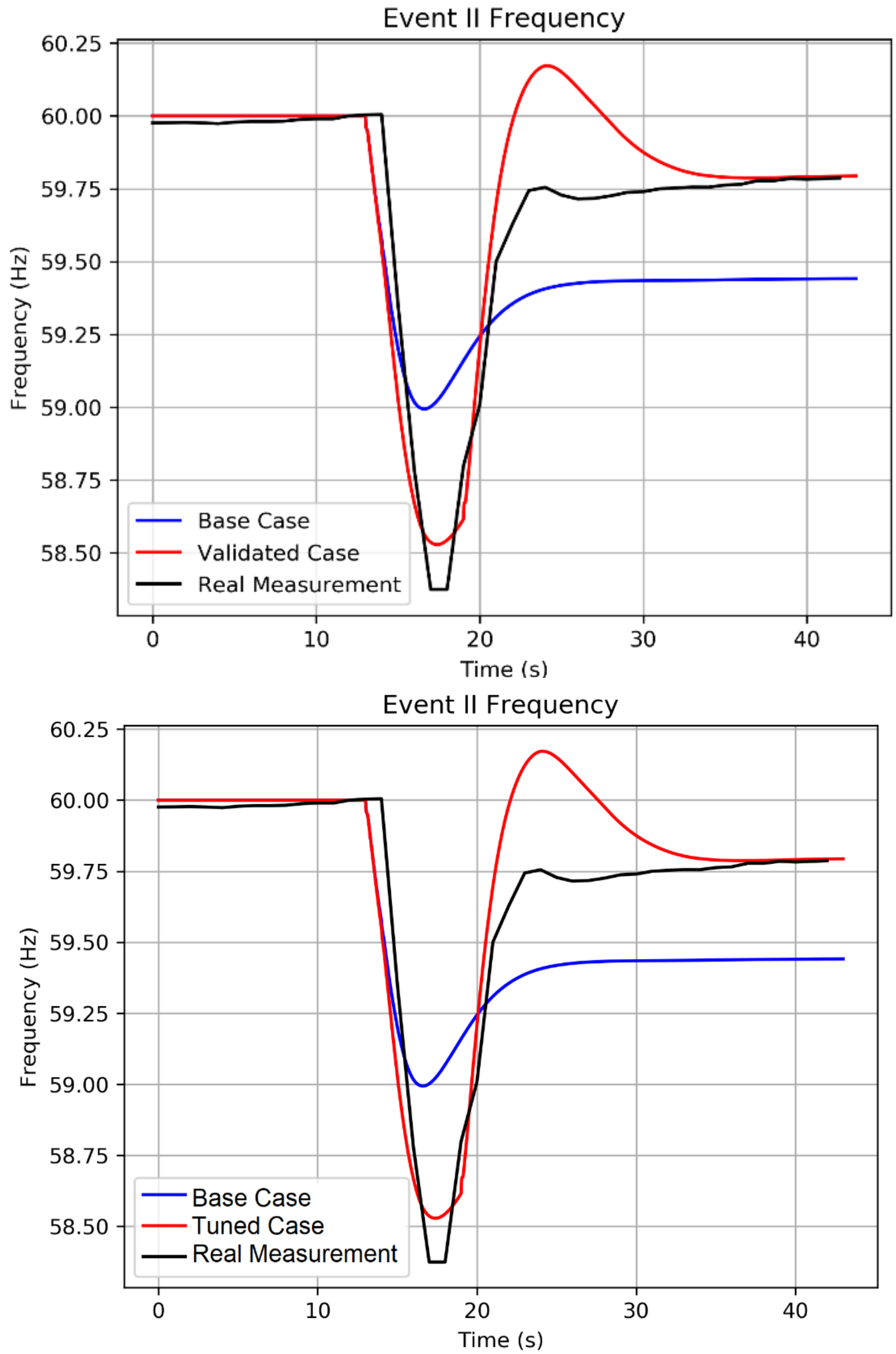


Figure 191. September 2021 event for model tuning

10.4.4 Considerations From Model Tuning Analysis

The model tuning results show that differences exist in the governor models settings and their response to large-scale events. These differences in the frequency response indicate governors of some machines might not be enabled in the field or are incorrectly modeled, and therefore, in-field evaluation is needed to confirm. Additionally, certain generator's droops and deadband settings might not be consistent with actual settings; however, because of the possibility that other modeling errors are not evaluated in this study, the parameters cannot be accurately assessed through the simulation and also require in-field assessments to confirm. Also, because modeling software always assumes a 60-Hz starting frequency, any events that do not begin at 60 Hz will have some discrepancy in the current generator output and headroom.

Considerations from our model tuning results are that:

1. Using higher-resolution generator data would provide more accurate timing for loss of generation events. Phasor measurement units near generators would be beneficial for post-event analysis.
2. Reviewing automatic load shedding protections in the field is needed to ensure the model has the most up-to-date information.
3. Evaluating generator equipment in the field in detail would provide more accurate input to the model and potentially highlight differences of equipment enabled in the field to that in the model. LUMA has contracted personnel to conduct this in-field evaluation.
4. Installing advanced metering infrastructure or phasor measurement units throughout Puerto Rico would provide critical information to accurately capture load shedding events. Additionally, phasor measurement units could capture load dynamics, which would help improve the load model assumptions. Currently, the load is modeled as static load, but with higher measurement data, accurate dynamic load models could be implemented to better represent the load response.

10.4.4.1 Future Work From Model Tuning

Model tuning should be repeated if data become available for more recent events. After in-field individual generator validation is completed, the model should be updated and assessed again to ensure its accuracy.

Other facets of model tuning that were not considered in this study include the dynamic load models and protection system settings. Combining the validation of generator, load, and the protection system into a comprehensive study would give further insight into the model inaccuracies. However, this effort requires load measurement at various locations and data for fault disturbances will be needed in addition to generation trips.

10.5 Stability Analysis for Very Near Term Using Electromagnetic Transient (EMT) Models

10.5.1 Motivation

Both bulk power system and distribution grid in Puerto Rico will be undergoing a rapid transition toward high penetration of IBRs, such as solar photovoltaics (PV), battery energy storage systems (BESS), and wind power generation. High IBR grids push conventional planning and positive sequence software tools to their limits, and transmission planners and system operators are faced with the need to conduct detailed studies using EMT models to investigate reliability issues related to integration of IBRs in weaker networks, IBR-to-IBR and IBR-to-grid control interactions, large and small signal stability, unbalanced power flows, ride-through capabilities, protection, power quality, short circuit studies, and black-starts. Industry experience worldwide (e.g., Australia and Hawaii) shows that areas with high shares of IBRs have a strong need for detailed EMT studies to ensure reliable operation. Considering the levels of expected deployment of IBRs in the LUMA grid (40%, 60%, and 100% by 2025, 2040, and 2050 respectively), the whole Puerto Rico power system will have high density of IBRs at any level (bulk power system, commercial and residential) necessitating detailed system-wide EMT studies.

10.5.2 EMT Models of IBRs

Any modeling effort is relevant only if valid and accurate models are used in the study. Model accuracy is critical for both EMT and positive dynamic modeling. For IBRs, the models need to be representative of the equipment installed in the field in terms of not only specific IBR model number and characteristics but also versions of control software. In an ideal case, fully validated IBR models[135] must be provided as part of interconnection requirements and interconnection studies for all new interconnecting resources. EMT models are important to ensure interconnection requirements, such as existing[136] and future LUMA technical interconnection requirements, are adequate for providing sufficient levels of reliability to the LUMA grid under any future gird scenario. Because equipment vendors for Tranche 1 and 2 deployment scenarios are still unknown, NREL developed its own EMT models for PV and BESS systems that have controls compliant with LUMA interconnection requirements and also have more advanced controls that can provide additional reliability, stability and resiliency services to the grid, such as GFM and black-start controls. NREL models for utility-scale PV and BESS plants were developed in PSCAD EMT software environment, and include the features shown in Table 36.

[135] In addition to having a fully validated power system model and fully validated model for conventional generators as well.
[136] "Technical Interconnection Requirements," NEPR-MI-209-0009, May 19, 2022

Table 36. Utility-Scale PV and BESS Plants Modeled in PSCAD EMS Software and Their Features

Technology Modeled	Features
Active power controls for PV and BESS in conventional GFL mode	• Following active power setpoints from system operator • Provision of spinning reserves • Participation in automatic generation control (AGC) • Primary frequency response with programmable frequency droop and dead band setting • Fast frequency response (FFR) with programmable settings • Inertia-like response (IBR response proportional to the rate of change of frequency, or ROCOF) with programmable inertia constants
Reactive power controls (in GFL mode)	• Operation in reactive power, voltage, or power factor control modes • Dynamic voltage support at the POI
GFM controls	• Droop-based GFM control with programmable settings to mimic operation of synchronous generators • Current limiting controls
Black-start controls	• Controls to energize and operate loads in the absence of grid during black outs (implemented for GFM BESS) • Soft-start controls allowing gradual increase of voltage during black-starts to avoid inrush current when energizing transformers and transmission lines
Fault ride-through controls (for both GFL and GFM mode)	• Ability to ride through balanced and unbalanced voltage faults (up to 600 ms ride-through during zero-voltage faults at POIs) • Ability to ride through frequency faults • Provision of desired levels of fault current during faults (in GFL mode) with capabilities of given IBRs • Current limiting controls during faults in GFM mode

In addition, NREL developed and implemented EMT models of other stability and reliability enhancing technologies such as synchronous condensers and STATCOMs.

10.5.3 EMT Model of Puerto Rico Power Grid Operated by LUMA

NREL developed an EMT model of LUMA grid in PSCAD in three steps:

1. A base case PSS/E model of LUMA system was converted to PSCAD using Electranix's E-TRAN software.
2. The base case PSCAD model was tuned using field-measured data of various contingency events provided by LUMA.
3. The PSCAD model was configured to represent the Tranche 1 scenario by adjusting loads, dispatched conventional generation and inclusion of PV and BESS plants at designated POIs.

The layer of PSCAD model representing the 230-kV transmission layer is shown in Figure 192. It includes 230-kV transmission lines, substations and generating plants interconnected with 230-kV transmission. The 115-kV layer is shown in Figure 193, including 115-kV transmission lines, substation, conventional generating plants and Tranche 1 PV and BESS plants with all the controls described in previous section. The PSCAD model includes an AGC block developed by NREL that provides active power setpoints sent to participating plants for frequency regulation with a 2-s time-step. The model is flexible and allows changing programmatically many settings for individual system components, such as enabling or disabling saturation models in transformers, activating different control options for IBRs, opening or closing substation circuit breaker, disconnecting generators and creating voltage faults at any location in the system. The model can be easily adapted to future possible transmission upgrades, network topology changes, increase or reduction of loads, variable load characteristics, and future or modified tranche scenarios. If needed, NREL has models of both onshore and offshore wind power plants that can be added to the model of LUMA grid at any POI. Some additional modeling conducted by NREL also includes grid strength studies complimentary to ones conducted by the Oak Ridge National Laboratory (ORNL) team to demonstrate impacts of various contingency conditions on system SCR under Tranche 1 and 2 scenarios.

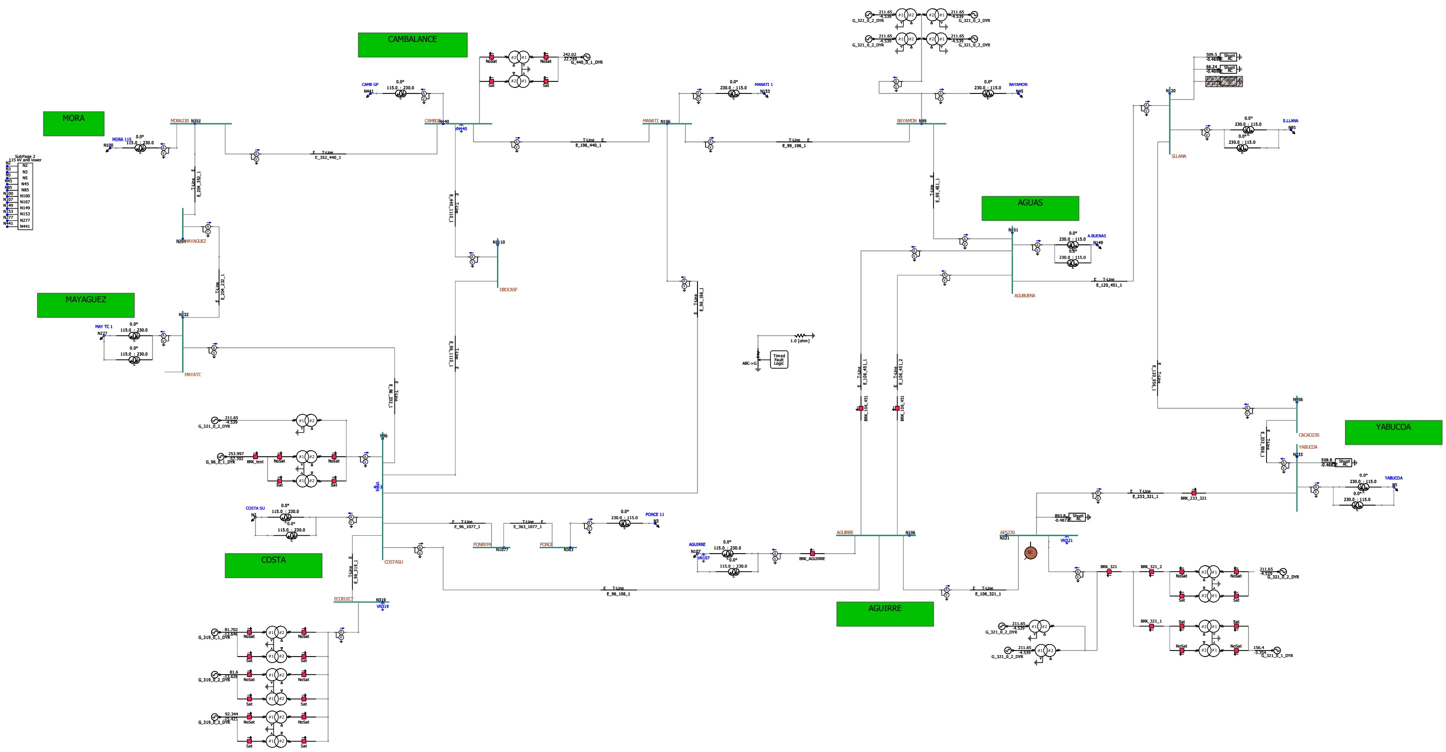


Figure 192. PSCAD model of LUMA grid: 230-kV transmission system

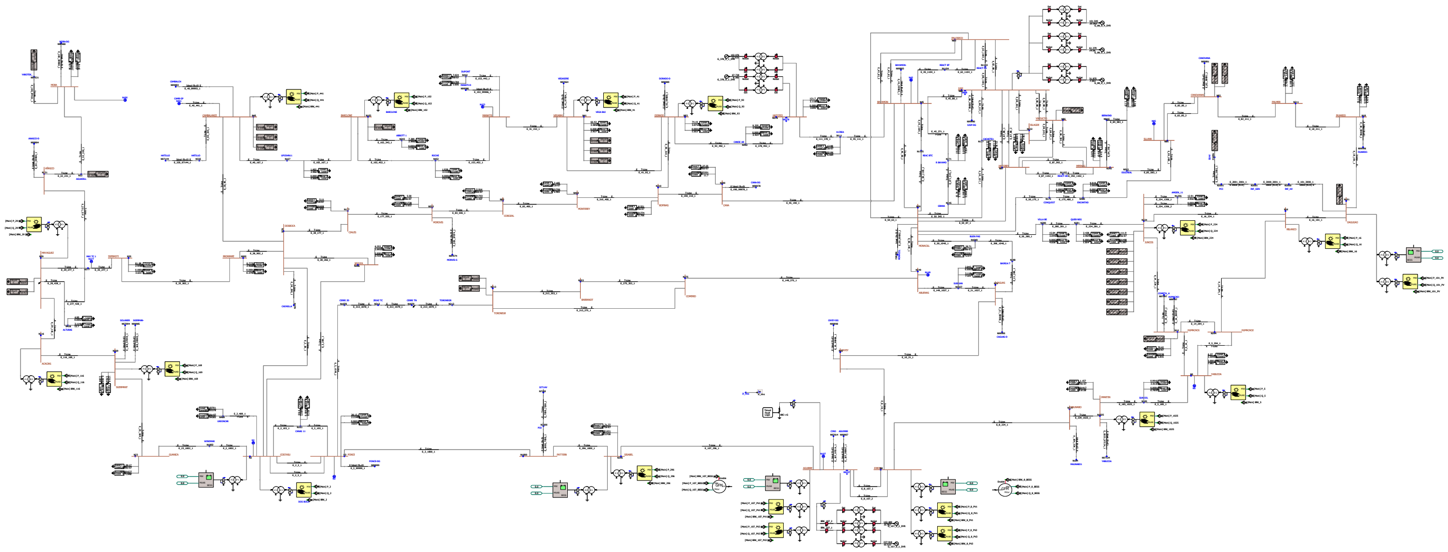


Figure 193. PSCAD model of LUMA grid: 115-kV transmission system layer with interconnected Tranche 1 PV and BESS plants

10.5.4 LUMA System Performance During Voltage Faults

In the event of a short circuit fault (line-to-line or line-to ground) anywhere in the power system and subsequent low voltages, it is important that IBRs not trip off because of low or zero voltage and resume power production after the fault is cleared. In an islanded system, with very high shares of IBRs, like the future LUMA grid, low-voltage ride-through (LVRT) ensures the full range of IBRs (PV, BESS, and wind) are available to operate the post-fault system and avoid cascading failures that may lead to territory-wide blackout; the same is also true for transient events resulting in excessive overvoltage conditions. The ability of IBRs to ride through low-voltage, zero-voltage and high-voltage faults is one of the most important reliability enhancing features the LUMA grid will need under Tranche 1 and 2 scenarios.

Fault ride-through (FRT) is recognized as part of LUMA's interconnection requirements. Attention also needs to be paid to repeated fault events that can happen in quick succession caused by intermittent faults or re-closer actions. If properly designed and controlled, IBRs can ride through repeated and longer low-voltage events. Arguably, IBRs can ride through repeated events better than synchronous generators. Main limitation for IBRs with DC links is that they need to be quickly controlled during repeated faults. In principle, BESS can ride through repeated and long low-voltage faults (Bialek et al. 2021). Wind and PV generation can do the same with adequate design of their DC-bus voltage controls. To aid protection system operation and post-fault voltage recovery, IBRs are normally required to inject reactive currents during LVRT. The magnitude of current injected during faults will depend on physical characteristics of individual IBR. Transient simulations that accurately represent IBRs are important to predict LUMA system behavior during voltage faults under Tranche 1 and 2 IBR deployment scenarios.

NREL has conducted simulations demonstrating LVRT performance of LUMA system under Tranche 1 scenario. Some examples of simulated cases are shown in Figure 194, with 150 ms most severe three-phase zero-impedance voltage faults introduced at the Mayagüez substation (left chart in the figure) and more centrally located Aguas Buenas substation (right chart). In both cases, all Tranche 1 PV and BESS plants operate in GFL mode and have their LVRT controls enabled. All plants are controlled to inject reactive current proportional to the voltage drop measured at plant POI, to assist the system with rapid voltage recovery after faults. In both examples, the system demonstrates robust ride-through performance and rapid voltage restoration to prefault level. Note that the magnitude of voltage drop at a particular location depends on its electrical distance from the faulted bus. However, faults of this type are widely visible by the whole system, which means all IBRs in the system will be exposed to the same fault and need to provide LVRT response.

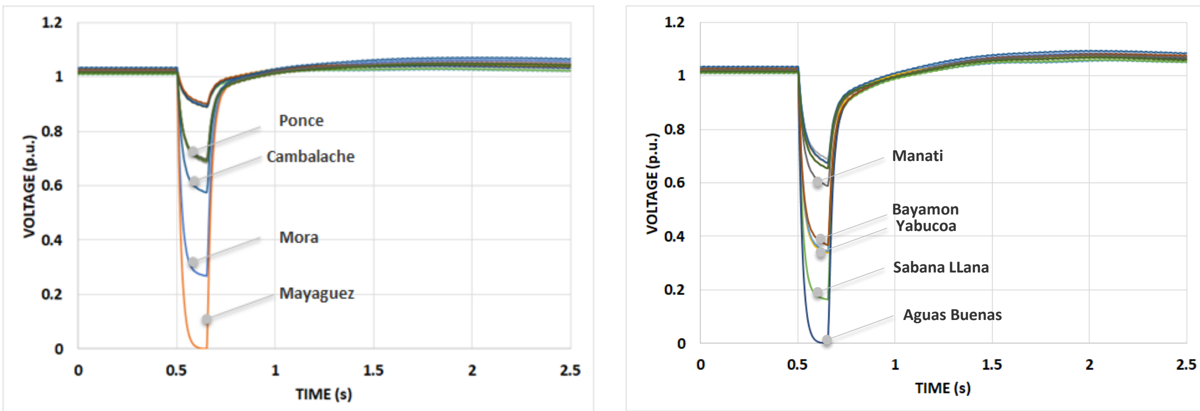


Figure 194. LUMA system response to 150-ms three-phase voltage fault in Mayagüez substation (left) and Aguas Buenas (right) substation

An example of simulated a 100-MW Tranche 1 PV plant LVRT is shown in Figure 195 (page 302). In this case, the PV plant operating in GFL mode is connected to the weaker POI (SCR=3) and is exposed to 100 ms three-phase (left) and single-phase (right) voltage faults at the 115-kV POI, which is some electrical distance away from plant terminals. The fault is initiated at t=5 s. The PV plant operates at about 90% capacity, so it has headroom to inject an extra 10% balanced current during the fault. This increase in instantaneous current amplitude during the fault can be observed in Figure 195 for both cases. Active and reactive contribution by this PV plant differs depending on type of the fault as can be observed in Figure 195. Similar simulated performance is observed by Tranche 1 BESS plants operating in GFL mode.

It is important to note that these simulations are conducted using generic models of PV and BESS inverters; the actual LVRT performance of vendor-specific equipment can differ with these presented cases. Flexible AC transmission systems, or FACTS, devices like synchronous condensers can be used in the system to maintain short circuit current levels for protection adequacy. However, the exact locations and capacities of synchronous condensers need to be studied for each of Tranche 1 and 2 scenarios.

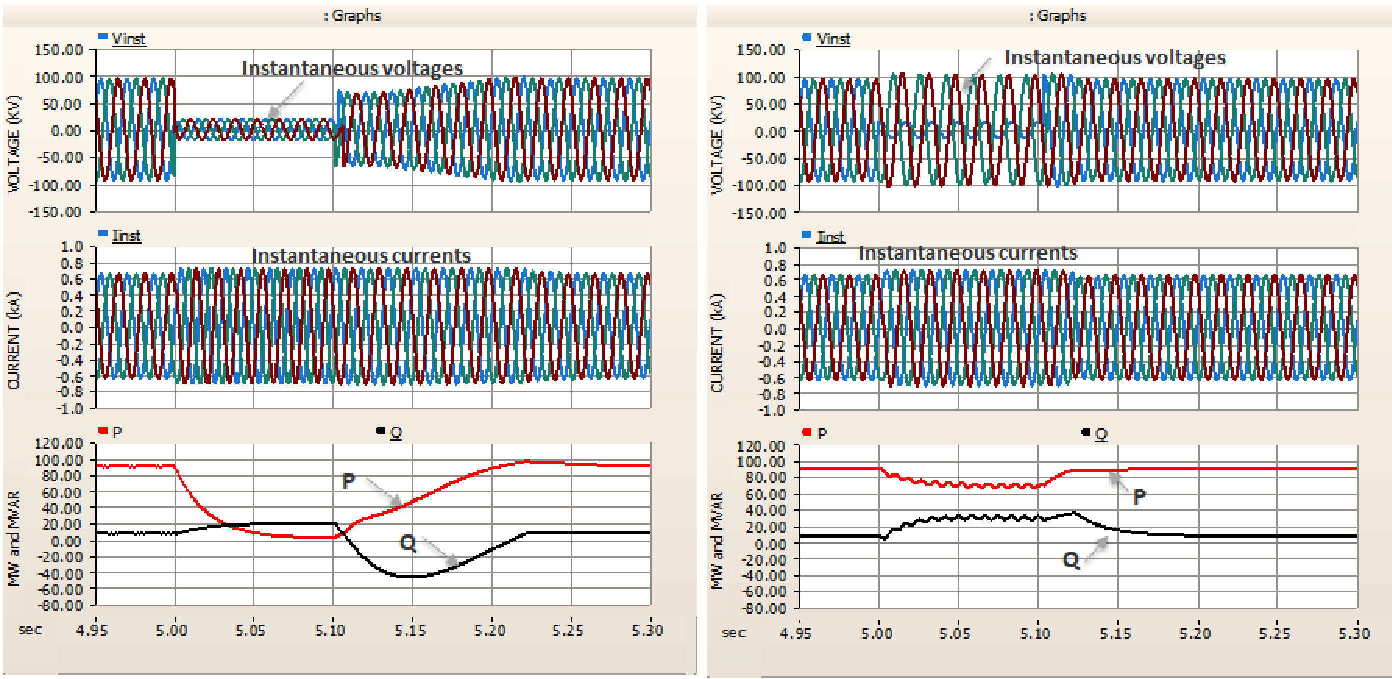


Figure 195. Simulated LVRT performance of 100-MW PV plant for (left) 100 ms three-phase voltage fault and (right) 100 ms single-phase voltage fault at 115-kV POI

10.5.5 Modeling Tranche-1 Frequency Response

At present, LUMA uses two types of services to manage the frequency after a major contingency occurs. First, service is provided by conventional generating plants with their inertial and primary frequency response, which is also called governor droop response. Second, service is the under-frequency load shedding (UFLS) that is used to arrest the frequency decline and restore the frequency if the first action is insufficient during large contingencies and leads to significant loss of infeed. Examples of recoded frequency events caused by trips of large generators in LUMA system are shown in Figure 196.

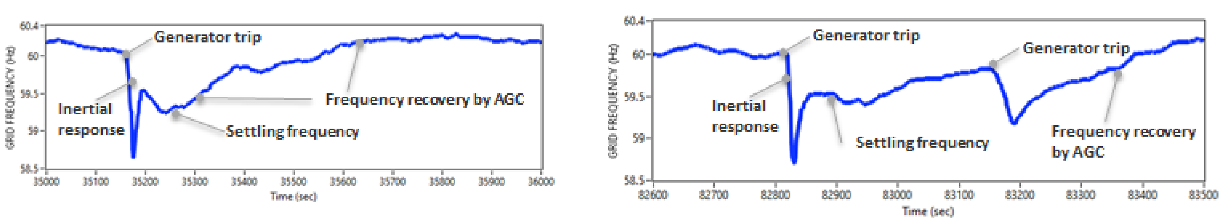
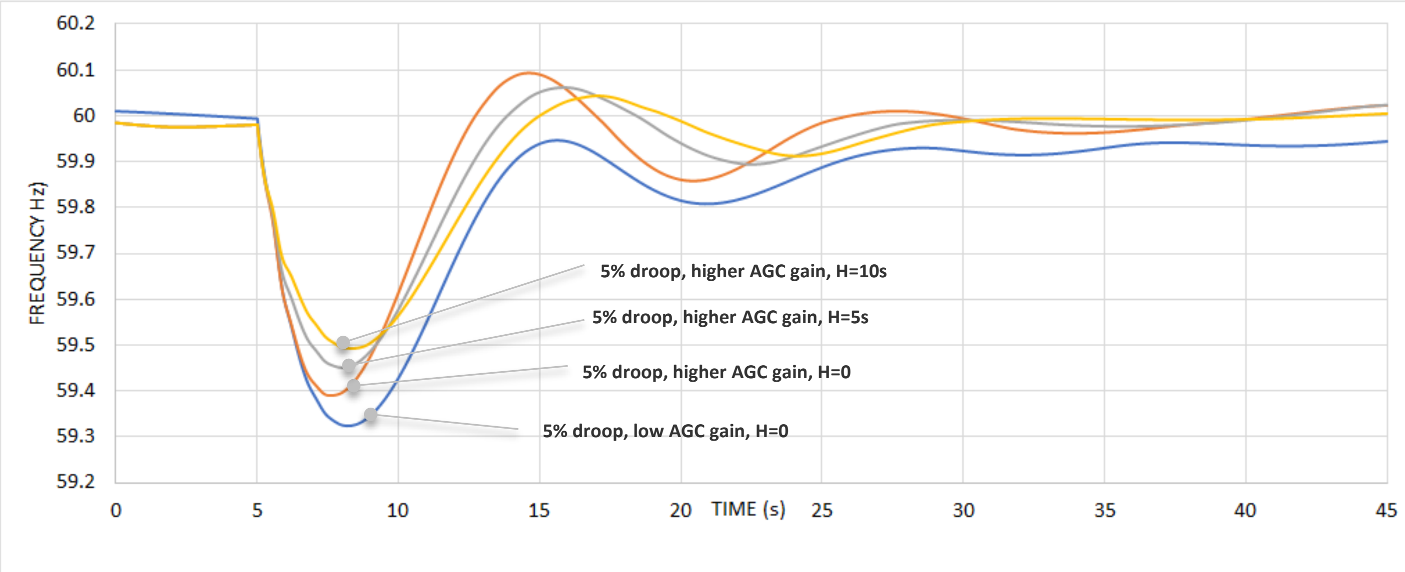


Figure 196. Examples of recorder frequency events on LUMA system

Inertial response, which is a natural response of rotating synchronous machines, provides initial arrest of frequency decline by reducing the ROCOF. Governors of generating plants are activated as frequency continues to decline, and they provide a response proportional to the magnitude of frequency deviation (primary frequency response or droop response). In case of insufficient inertia and droop response, UFLS may be activated. Next, the AGC takes over to gradually restore the balance between load and generation and bring frequency back to the prefault level.

Under the Tranche 1 scenario with 40% IBR penetration, the system frequency response may degrade because many synchronous machines will be retired or not dispatched. To maintain and improve the system frequency response, IBRs need to provide many of the services that conventional generation has traditionally provided. An example of Tranche 1 frequency response is shown in Figure 197, when all central BESS plants deployed under Tranche 1 scenario provide various types of active power controls (PV plants do not provide any service and are operating at the maximum production levels; BESS plants at the beginning of the event are synchronized with the grid but operating at zero active power).

These cases are simulated for a similar level of generation plant trip as in recorded cases shown in Figure 196 (loss of about 250 MW of generation). Simulation results shown in Figure 197 indicate significant improvement in system frequency response compared to the existing system. Activation of 5% frequency droop control in BESS plants combined with BESS plant participation in AGC (high or lower levels of participation corresponding to the high or low AGC gains respectively) and inertia-like response (corresponding to lower or higher emulated inertia constant) facilitates significantly improved frequency response compared to the response of the existing LUMA system. In particular, the best performance is demonstrated when all BESS plants are emulating inertia-like response (inertia constant H=10 s), operating with 5% frequency droop and providing a higher level of AGC participation.



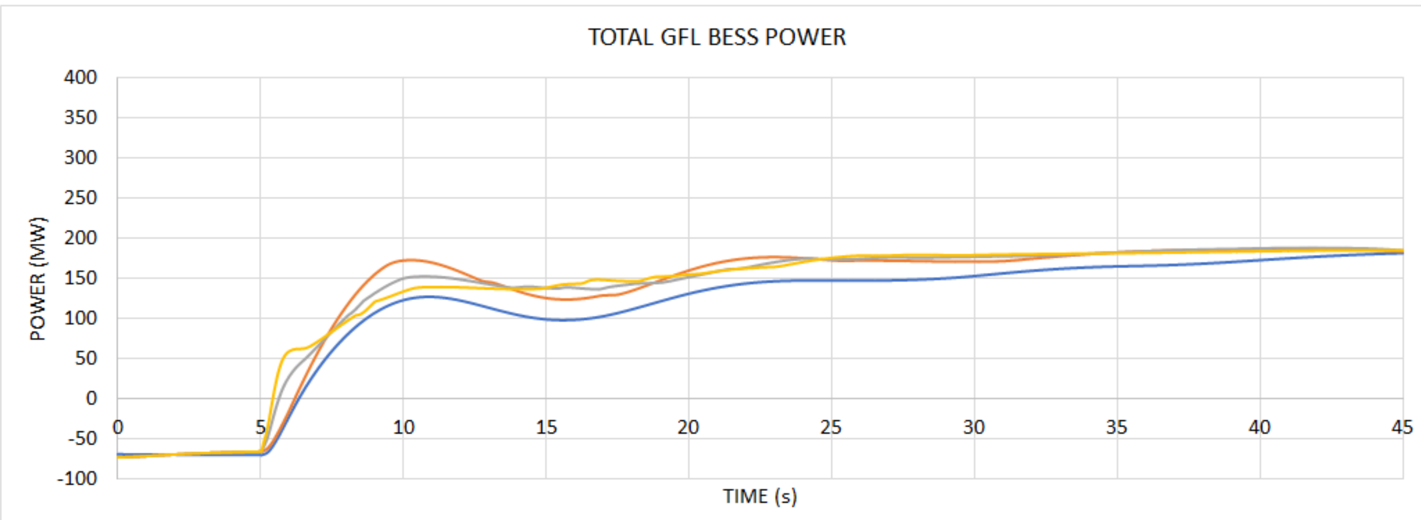


Figure 197. LUMA frequency response (upper graph) and active power of all Tranche 1 BESS (lower plot) operating in GFL mode with different controls

The frequency droop value of 5% is a common droop level used in many power systems. Using more aggressive droops will produce faster and larger responses by participating units but might also create a risk of instability. NREL conducted simulations using a more aggressive (1%) frequency droop levels provided by Tranche 1 BESS plants. For simulated cases, the system demonstrates stable performance as can be observed in Figure 198. For two cases (250-MW and more severe 500-MW generation loss), the system exhibits robust and fast frequency recovery.

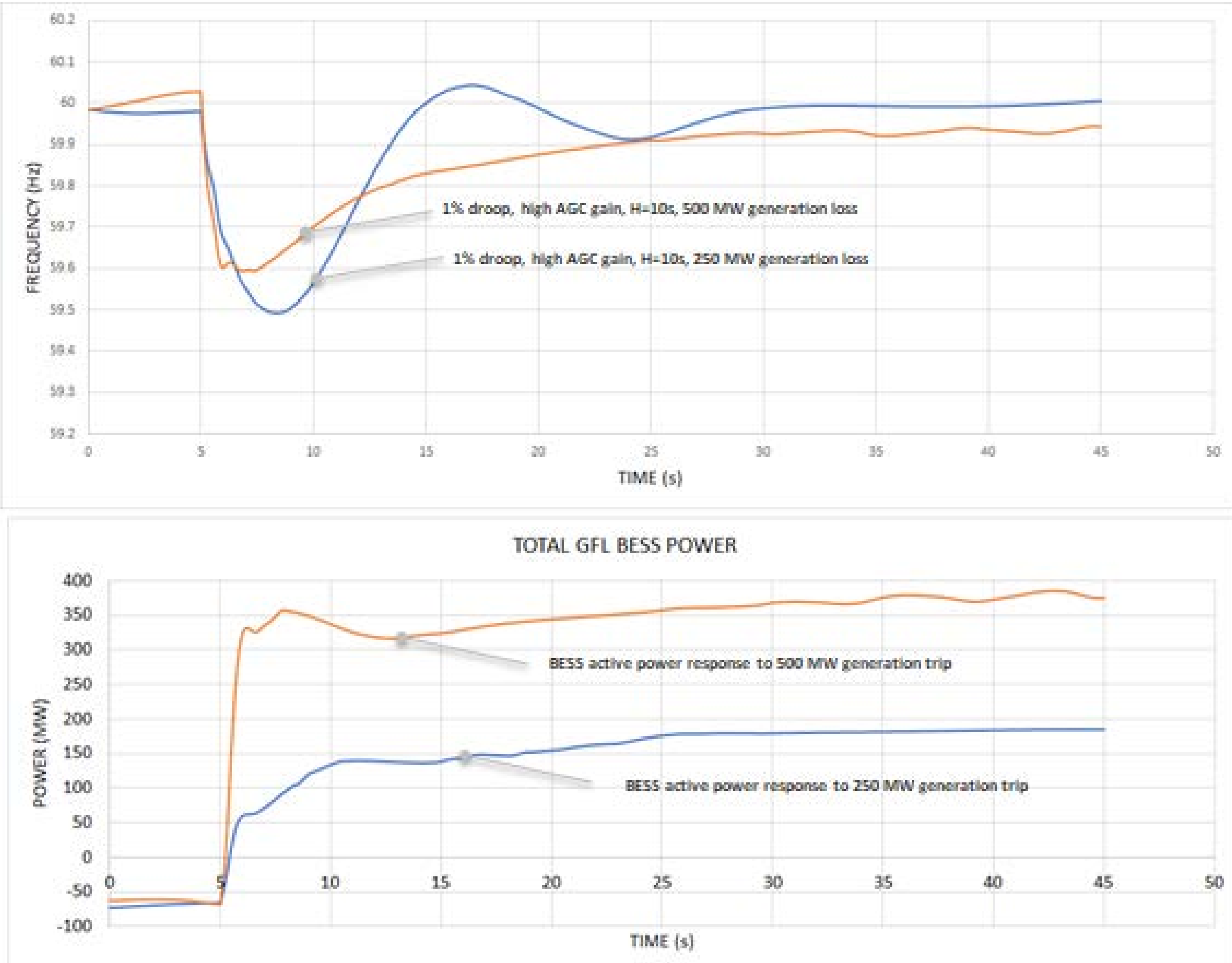


Figure 198. System frequency response during 500-MW generation trip

System frequency is shown in the upper chart. BESS active power is shown in the lower chart.

Similar performance can also be achieved by PV generation if participating PV plants operate in curtailed mode with sufficient headroom available to provide response similar to what BESS plants provides in the above examples. These frequency response examples demonstrate that Tranche 1 IBRs can provide adequate and improved (compared to the current system) frequency response when operating in GFL mode and using controls required by the existing LUMA interconnection requirements.

10.5.6 Considerations

All power grids have natural oscillation modes that can range from subhertz to hundreds of hertz modes. If poorly damped, some of these modes can become unstable as power systems undergo the transition. It is important for LUMA to ensure such modes are adequately damped in Puerto Rico grid and the system stability is maintained in robust and secure way. Apparently, the LUMA grid is secured from subsynchronous resonance by its design because LUMA grid does not have conventional series-compensated transmission lines. However, subsynchronous resonance caused by IBRs in weak grid scenario is still possible. Electromechanical oscillations may present themselves in a system that has a mix of synchronous machines and IBRs. These effects may vanish under the 100% scenario. In the case of large-scale deployment of synchronous condensers, the need for damping of electromechanical oscillations may not disappear completely, even in the 100% case. In addition, low- and high-frequency oscillations can be caused by control interactions between controllers of IBR plants and small signal-stability issues (with similar phenomena observed in the Hawaiian and Australian grids). Such stability issues must be identified, thoroughly investigated, and addressed in the early planning stages using stability assessment tools, such as the NREL's Grid Impedance Scan Tool (GIST) for PSCAD.[137] GIST also allows for identification of sources of oscillations and evaluation of mitigating solutions if such instabilities appear during system operation at any stage of IBRs deployment process.

Damping of supersynchronous oscillation modes is also important in LUMA's future IBR-dominated grid. IBRs control their output voltages and currents through high bandwidth control loops. Such fast controls, interacting with each other, may cause oscillations leading to instabilities at supersynchronous frequencies. Project and vendor-specific valid IBR models are needed to properly simulate and address such potential stability challenges. Using only generic IBR models may produce overly optimistic or pessimistic results and should be avoided for planning and reliability assessment purposes.

10.5.7 Consideration from EMT Modeling for Very-Near-Term Analysis of Tranche 1 Addition

- The existing LUMA system has frequency response and regulation challenges that need to be investigated and addressed for secure implementation of Tranche 1 and Tranche 2.
- Faults anywhere in the 230-kV transmission impact the whole system, and the faulted line or substation needs to be isolated as soon as possible.
- IBR-based grids can have better transient performances than existing grids if they are correctly designed and controlled.
- Active power controls by Tranche 1 GFL BESS improve frequency response compared to the existing LUMA system.
- More aggressive controls improve frequency stability of the system, but they need to be verified with vendor-specific models.

Considerations from the analysis of Tranche 1 include that Puerto Rico:

- For Tranche 1, set up all inverters to operate with voltage and frequency supporting functions even in GFL mode (with existing minimum technical requirements), to ensure the system satisfactory transient performance.
- Make both active and reactive power controls available for GFL BESS. All substation level utility-scale BESS plants need to be integrated into the AGC system. Controls for inertial response, FFR, primary frequency response need to be available. Voltage and reactive power controls need to be available.

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[137] "Grid Modernization: Impedance Measurement," NREL, https://www.nrel.gov/grid/impedance-measurement.html.

- Ensure vendor-specific models are integrated into the electromagnetic transient model of the LUMA system (after vendor selection is completed) for electromagnetic transient (EMT) simulations.
- Use EMT models to help power grid planners gain confidence in simulating scenarios with IBRs like renewables and BESS.

10.6 Stability Analysis for 100% Instantaneous Penetration of Inverters

In this section, we analyze bulk system-level stability at a higher level of granularity, using phasor-based dynamic models in the PSS/E software, which allows for consideration of various effects such as generation and energy storage dynamics, load dynamics and aggregations of DERs, and interactions between load dynamics and DER FRT capability—all of this covering the transmission and subtransmission (230-, 115-, and 38-kV levels) system—as well as advanced GFM inverter controls and traditional GFL inverter controls.

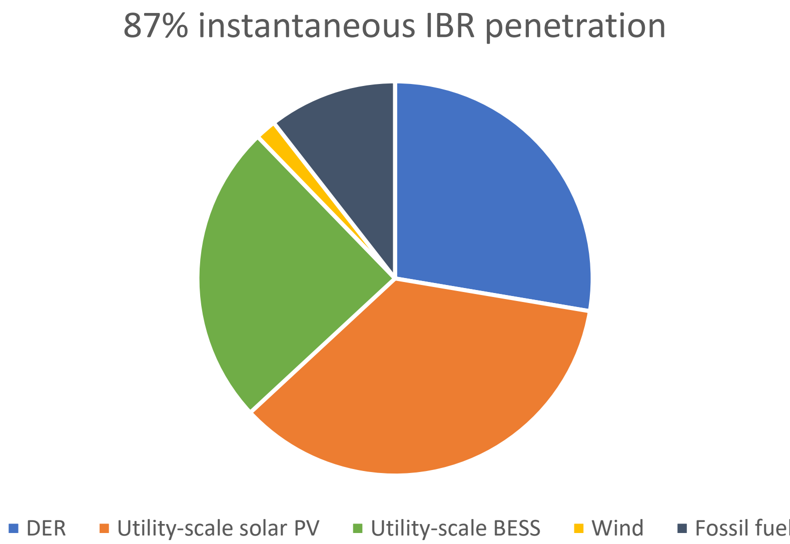
The simulation results in this section show large voltage and frequency deviations for FIDVR, which are caused by motor load stalling and are followed by DERs tripping by low voltage. Results show that 300–830 MW of BESS with GFM functionality and FFR (1% droop) can be effective to mitigate the large frequency deviations when this effect is present.

10.6.1 Background and Scenarios

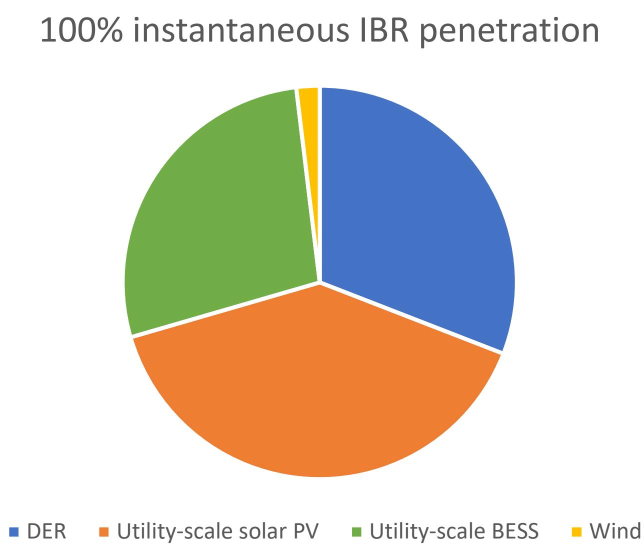
Power systems transient stability analysis evaluates the grid stability and contingency responses using an extensive library of power system dynamic models for individual grid components, such as synchronous machine and IBRs for power generation units, transmission protection equipment and customized configurations, and composite load and emerging aggregation of DERs. As a result, one main focus of such an analysis is to formulate scenarios that (1) achieve 100% instantaneous renewable penetration for some hours in the year and (2) evaluate the grid stability and whether the system can withstand single contingencies during hours at 100% renewables. It is important to note that 100% instantaneous IBR penetration may occur as soon as the objective of 40% annual energy from renewables is reached or sooner.

A group of scenarios and power systems dynamic simulations are summarized as follows:

- 87 % Instantaneous Penetration
    - 1.2 GW of DERs
    - 1.55 GW of PV generation
    - 1.08 GW of BESS
    - 75 MW of wind
    - 463 MW of remaining synchronous generation
- **100% Instantaneous Penetration:** Same as 87% case but with synchronous generations offline



(a)



(b)

Figure 199. Generation power output per technology (DER, utility-scale solar PV, utility-scale BESS, wind, and fossil fuel) for (a) 87% instantaneous IBR penetration case and (b) 100% instantaneous IBR penetration case

10.6.2 Methodology

In this study, the team from the national laboratories for this task (PNNL, NREL, and ORNL) received a grid planning model from LUMA and made extensive efforts to include state-of-the-art dynamic models for renewable energy and BESS; in addition, a systematic approach to ingest grid expansion planning data and export aggregated load and DER representations. The grid models and technical tools adopted in this study are:

- GFM and GFL Control Model for IBRs:
  - Renewable energy generations including solar and wind will connect to the grid through power electronics-based inverters, which present new dynamic behaviors compared to the synchronous machines in existing Puerto Rico generation fleet. In general, there are two kinds of inverter control technologies: GFM and GFL controls.
  - In this study, the Task 8[138] team adopted the PNNL-developed, WECC-approved generic model, REGFM_A1[139] for GFM representation and the WECC-approved generic model modules, REGC, REEC, and REPC,[140] for GFL representation. The corresponding model parameters are following the WECC-approved model specifications (Du et al. 2021) and Puerto Rico utility practices.
- **PNNL's for Automated Generation of Composite Load Model:** We adopted this tool for dynamic model preparation of WECC-approved composite load model, CMLDBLU1,[141] and a group of motor load variations are generated to test the system response. Additional information is provided in Section 10.7.1 (page 314).
- **Aggregated DER Model Preparation for Transmission Network Representation:** We adopted the WECC-approved DER model, DER_A,[142] to properly represent the dynamic behavior of aggregated dynamic behavior of DERs in the system; in addition, such modeling also enables the corresponding DER protection configuration, following IEEE 1547. Details are available in Section 10.7.1.2 (page 315).
- **DER Protection Model Following IEEE 1547-2018:** In the present analysis, the DERs are modeled as per IEEE 1547-2018 by considering the voltage and frequency ride-through requirements. This is important to support the system-level dynamic behavior with sizable DER penetration levels. Additional discussion is provided in Section 10.7.1.2 (page 315).
- **Transmission Protection Equipment and Customized Configuration:** The transmission network is protected by various protection relays and schemes. In this study, we adopted the under-frequency line tripping (UFLT.dll) from LUMA and explored possible extensions to include more relay models. It should be noted that additional protection coordination work is needed to fully evaluate the grid strength and coordinated control throughout the Puerto Rico power grid.

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[138] All PR100 tasks are listed in Figure 2, page 7.
[139] "WECC Approved Dynamic Model Library," Version September 2023, effective date September 27, 2023, https://www.wecc.org/Reliability/Approved Dynamic Models September 2023.pdf.
[140] See Footnote 139.
[141] See Footnote 139.
[142] See Footnote 139.

10.6.3 Data Input into Dynamic Models

The following information was used to create the models utilized in this subsection:

1. **Generation:** LUMA provided a list of power system substations and transmission buses that are compatible for interconnection consideration for both renewable generation and BESS. Such information is connected to PNNL's Electrical Grid Resilience and Assessment System[143] geographic information system to evaluate the locations and nearby infrastructure facilities.
2. **Transmission:** LUMA provided a Puerto Rico power grid planning case (the 2026 LUMA Day-Peak Planning Case) as the modeling basis for future high penetration of renewable energy scenarios. Additional power flow modifications are performed to adjust generation mixture, update POI network parameters, and include composite load model and aggregated DER representations.
3. **Distribution:** The bulk power system modelers of this section adopted the information from Section 9 and used the Distributed Generation Market Demand Model (dGen)[144] projections for DER adoption for a future year and considered the residential and nonresidential rooftop PV. For the results shown in this subsection, the DER projections from 2028 are used. The residential DERs are categorized as one-phase DERs, and nonresidential DERs are categorized as three-phase DERs. Moreover, the municipality level DERs are translated to distribution feeders by Sandia National Laboratories as part of the distribution feeder work; then, these feeder IDs are added to the associated transmission network buses where the aggregated DERs (DER_A models) are connected.
4. **Protection:** Under-frequency line tripping (UFLT) models for Puerto Rico power grid are included, which is from the full simulation package provided by the LUMA energy planning engineering team. UFLT models disconnect a few 38-kV lines when system frequency drops below certain thresholds.

10.6.4 Results

The simulation results based on the power system dynamic models used are evaluated using the Siemens PTI's PSS/E software, which is compatible with the grid operator's modeling practice. In addition, the inclusion of the state-of-the-art GFM control provides insights to new paradigm of Puerto Rico grid stability and dynamics. The key takeaways are:

1. GFM inverters will be key for Puerto Rico to operate with high renewables in the short term.
2. GFM batteries can contribute significantly with primary frequency control.
3. Additional system-level assessment is required for future grid operational dynamics.

Simulation results are provided here, to illustrate the grid stability considering the power system dynamic models used.

[143] "EGRASS," PNNL, https://egrass.pnnl.gov/
[144] "Distributed Generation Market Demand Model," NREL, https://www.nrel.gov/analysis/dgen/

A comparison of active power and frequency ($P \sim f$) droop control parameters is given in Figure 200 and Figure 201, in which a 1% GFM droop configuration shows better system response in face of severe system disturbance. one percent droop corresponds to FFR as stated in IEEE Standard 2800-2022.

In particular, Figure 201 shows simulation results for large frequency deviations caused by a fault in the transmission system that causes motor load stalling driving the voltage down (FIDVR effect), followed by DER tripping by low voltage. The FIDVR effect followed by DER tripping is discussed further in Section 10.7 (page 313). The large frequency deviations in Figure 201 can be a serious reliability concern for the systems. It can be seen in the figure that FFR (1% droop) can help mitigate the frequency deviations.

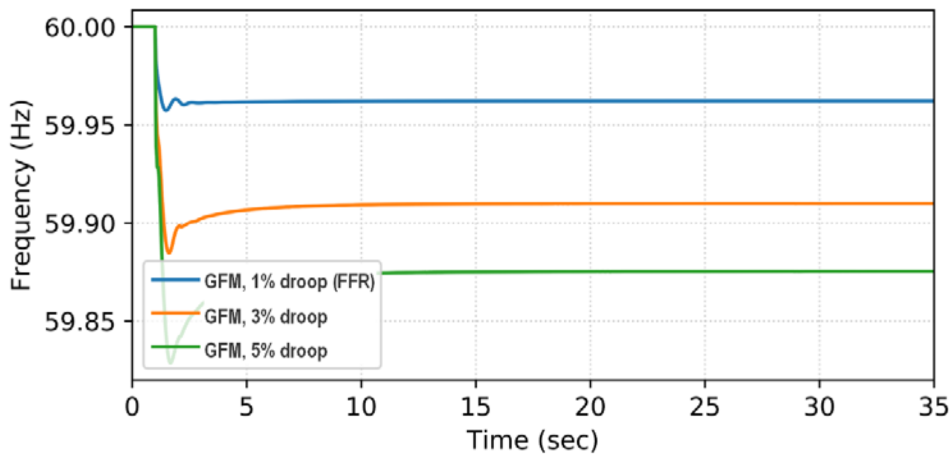

Figure 200. System frequency for single contingency of generation tripping for GFM inverters and droop-based FFR

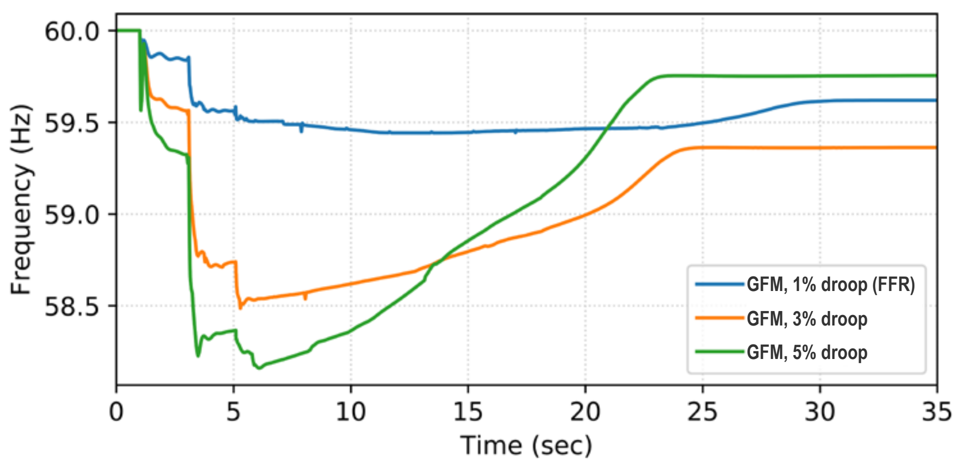

Figure 201. System frequency for severe bus fault contingency for GFM inverters and droop-based FFR

In addition, an example of single generation contingency is evaluated using different renewable energy dynamic models. In Figure 202, the system frequency dynamic response of the system for various control configurations is presented. In one case all PV solar generation was configured with GFM control which has inherent frequency response. In the second simulation in the figure, GFL model with frequency response function was configured for all PV generators. And in the third simulation of Figure 202, GFL model without frequency response was configured for all PV plants. In all cases, BESS plants are modeled as GFM inverters with FFR (1% droop). It is observed that acceptable performance for single generation contingency is achieved with FFR and GFM capabilities in all BESS (800 MW), even when solar plants are not contributing to frequency response. Moreover, national laboratory staff and LUMA staff collaborated in a research paper that shows that 300 MW of GFM BESS will significantly improve frequency response in Puerto Rico grid when after the loss of 500 MW from larger generation plant outage, like those of Aguirre and Costa Sur thermal plants (Nassif et al. 2023).

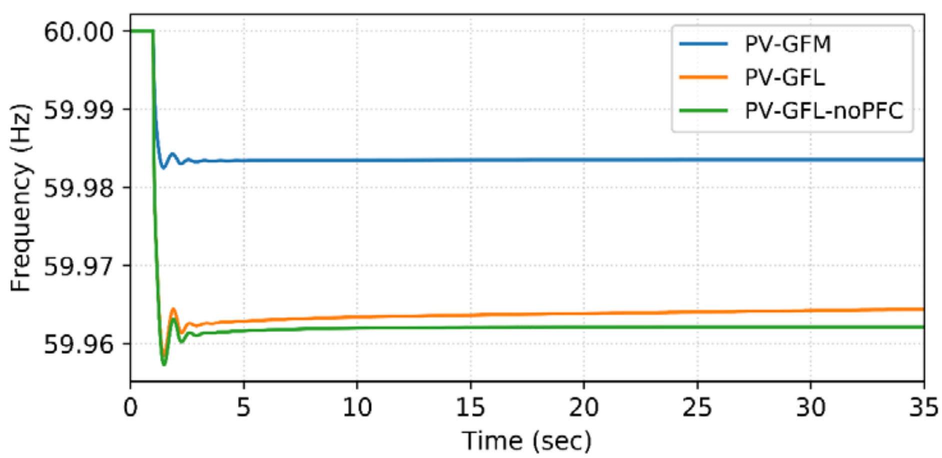

Figure 202. Frequency response to 90-MW outage for 830-MW GFM batteries and GFM and GFL utility-scale PV

In summary, with the continuous growth and deployment of smaller and more distributed utility-scale generation, energy storage, and DERs, it is important to evaluate system stability considering various power electronics-based inverter technologies, especially considering that GFM inverters are not yet widespread in bulk power systems. This also aligns with the needs of Puerto Rico power grid planning and operations to (1) develop detailed technical requirements for GFM inverters, expanding on the latest requirement that LUMA outlined—and more importantly, (2) perform additional studies for droop tuning and sensitivities as the generation mix changes, and (3) if possible, begin installing GFM inverters or work on aggressive pilot projects in the short term for energy storage and solar plants. Such efforts will also enable the grid operator to understand the potential benefits of utility-scale energy storage, get first-hand experience and operational knowledge especially regarding frequency control and evening ramping support.

10.6.5 Considerations

Advanced inverter controls, like grid-forming, voltage, and frequency supporting functions, are key for when the system approaches 100% instantaneous inverter penetration. Instantaneous penetration refers to hours in which the system is operated with all IBRs, without any traditional synchronous generator. Such conditions could start appearing soon when the system reaches 40% annual energy produced from renewables. The 100% instantaneous penetration conditions will become more and more common as the annual energy produced from renewables continues to increase to reach 60% and 100%.

For conditions with 100% instantaneous inverters, considerations include that Puerto Rico:

- Ensure utility-scale renewables and battery storage have robust settings for low- and high-voltage ride-through capabilities to avoid disconnection during low-voltage conditions that could happen during FIDVR and other events. Improved system protection would provide better stability during severe faults.
- Use inverter controls, such as batteries with GFM inverters, to significantly improve system reliability immediately, which are key for when the system approaches moments of 100% instantaneous inverter penetration.
- Install grid-forming and black-start controls on energy storage and grid-supporting controls in all renewable generation with connection to an AGC system in the near term.
- Install advanced control in all resources in the future, including grid-forming, voltage and frequency support, black-start capability, and connection to AGC systems.
- Adopt IEEE 2800 Standard as a base for requirements for IBRs and define specific requirements for inverter operation in Puerto Rico.
- Define requirements for GFM inverters in Puerto Rico as additional requirements on top of the base requirements in IEEE 2800 Standard.

10.7 Modeling of Load Dynamics and DER Dynamics

This section describes load dynamic modeling and aggregated DER representation to study dynamics on the full transmission and subtransmission system with phasor-based dynamics in PSS/E software. Simulations are shown for interactions between low voltage produced by stalling of motor loads and LVRT tripping from DERs. As discussed in the previous subsections, these DERs tripping could lead to large frequency deviations.

From the analysis presented in this section, it can be concluded that two solutions could be implemented to avoid reliability problems from load motor stalling and subsequent DER tripping. First, DER FRT capability should be robust to voltage deviations, with IEEE 1547 Category III FRT settings as proposed by LUMA, to avoid unnecessary disconnections during and after transmission faults. Second, additional studies of current air conditioning load composition will be beneficial to understand the potential for FIDVR to cause reliability concerns currently and in the future. Third, adopting variable frequency drive (VFD) air conditioners could help avoid the motor-stalling effect that potentially causes voltage instability. VFD air conditioners are currently available in Puerto Rico and expected to replace legacy air conditioners in the future; however, the current penetration of legacy equipment and the rate to which they will be replaced is currently unknown. And fourth, installing high-resolution measurements (phasor measurement units) and their associated communication infrastructure could be very beneficial to detect and analyze FIDVR events in the current and future system to study stability events on a regular basis.

This section is organized into two main parts: Section 10.7.1 (page 314) describes modeling and results for aggregated representations of loads and DER at the transmission level, which allows for analysis of full bulk system; Section 10.7.2 (page 324) covers transmission and distribution cosimulation, where a detailed feeder model is cosimulated with the transmission and subtransmission dynamics model to gain additional insights and details on what is happening internally in the distribution feeder. Finally, Section 10.7.3 (page 330) summarizes the key considerations from the load and DER modeling at the bulk power system.

10.7.1 Transmission Simulation with Aggregated Representation of Loads and DER Dynamics

Power system stability is classified into rotor angle stability, voltage stability and frequency stability, along with the newly added classification of resonant stability and converter stability. The load and DERs primarily have significant roles in voltage and frequency stability. As per the definitions and classification of power system stability (Hatziargyriou et al. 2021), voltage and frequency stability is divided into long-term stability and short-term stability.

Another key characteristic of power grids is the increasing presence of DERs, usually in the form of rooftop PV; larger, community/utility-scale PV; and BESS. DERs also have their own dynamic responses and need to be accurately represented to ensure the system response is reasonable and well captured. The DERs interconnection is governed by some standards, such as California Rule 21, Hawaii Rule 14, and the more recent IEEE 1547 (Basso 2014). In the present analysis, DERs are modeled as per IEEE 1547 by considering the voltage and frequency ride-through requirements.

Here, we present the observations of interactions of dynamic models of loads and DERs that are added to the bulk energy system models for a possible high renewable future grid model for Puerto Rico, and we introduce the composite load model. We also present IEEE 1547-2018 ride-through capability along with some sample simulation results and discussion intended to provide more awareness and insights as the Puerto Rico grid transitions to a high renewable resilient and reliable grid in the future.

10.7.1.1 Importance of Dynamic Load Models and Aggregated DER Models

The WECC composite load model is an aggregated load model that is accepted industry-wide and is used to model the dynamics of the lower part of the system. Figure 203 shows the key components of the WECC composite load model. The $3-\phi$ induction motors, which represent small, medium, and large industrial loads, are usually equipped with the undervoltage relays to trip the motor to prevent them from stalling. The $1-\phi$ induction motor typically represents residential air conditioning and compressor loads; the other loads are all static load models. The PV generation that are DERs are also dynamic models and use the DER_A model. Various power system solvers have the composite load model and the DER_A dynamic model implemented in them. In various versions of PSS/E, composite load models and DER_A model are implemented, and these can be modeled separately.

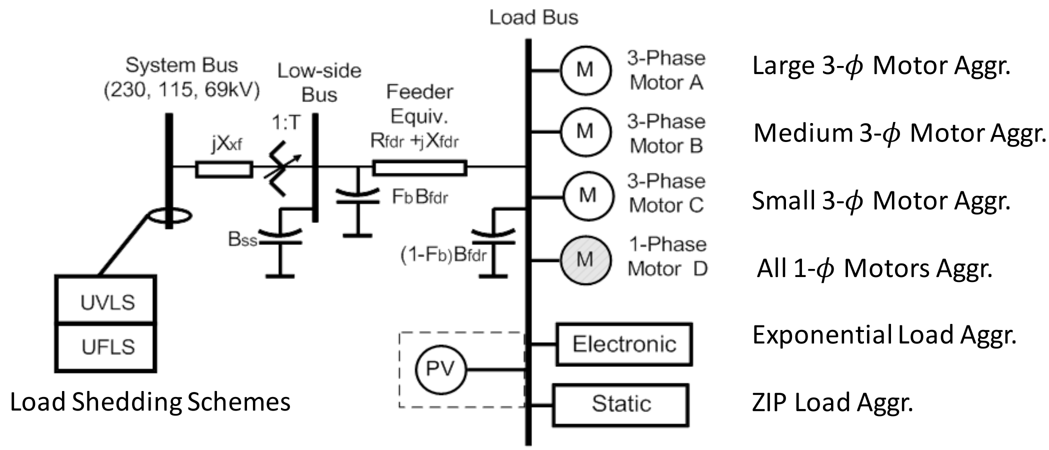

Figure 203. Structure of the composite load model

WECC (2015)

10.7.1.2 Modeling Approach Used for Puerto Rico Grid Models

The Load Modeling Data Tool[145,146] developed by PNNL can augment power grid models with composite loads and aggregated DER models. This tool uses specific inputs about the load buses where the composite loads will be added and parameters along with the location and parameters for the DERs. For PR100, the DERs are added independently and not combined with the latest composite load model to enable inclusion of additional relays to enable modeling the FRT settings for the DERs.

10.7.1.2.1 PSS/E Model Augmentation and Dynamic Simulations

The flow of input data and the steps involved to perform accurate dynamic simulations by including the composite load model, DER_A models, and the FRT relays models is shown in Figure 204. The power flow case is modified to include generators to represent the DERs. In case the power flow models have net load modeled at the load bus, the loads need to be updated to represent only the native load, so the DERs can be modeled as generators to enable inclusion of FRT relays.

10.7.1.2.2 Adding IEEE 1547 FRT Relays Models Along With the Dynamic Models for DERs

IEEE 1547 is a DER interconnection standard that recommends desired operation and response of DERs to enable DERs providing certain grid services. A critical part of the DER response is the inclusion of the DER ride-through relays models to capture inverter's ride-through capability. The DERs are all modeled as machines with DERs. A model and the FRT relays are added, and the detailed configuration information is given in Figure 205 and Figure 206.

[145] "Load Model Data Tool: Open Source, PNNL," https://www.pnnl.gov/copyright/load-model-data-tool-open-source.

[146] "Open-Source High-Fidelity Aggregate Composite Load Models of Emerging Load Behaviors for Large-Scale Analysis," https://www.pnnl.gov/projects/open-source-high-fidelity-aggregate-composite-load-models-emerging-load-behaviors-large.

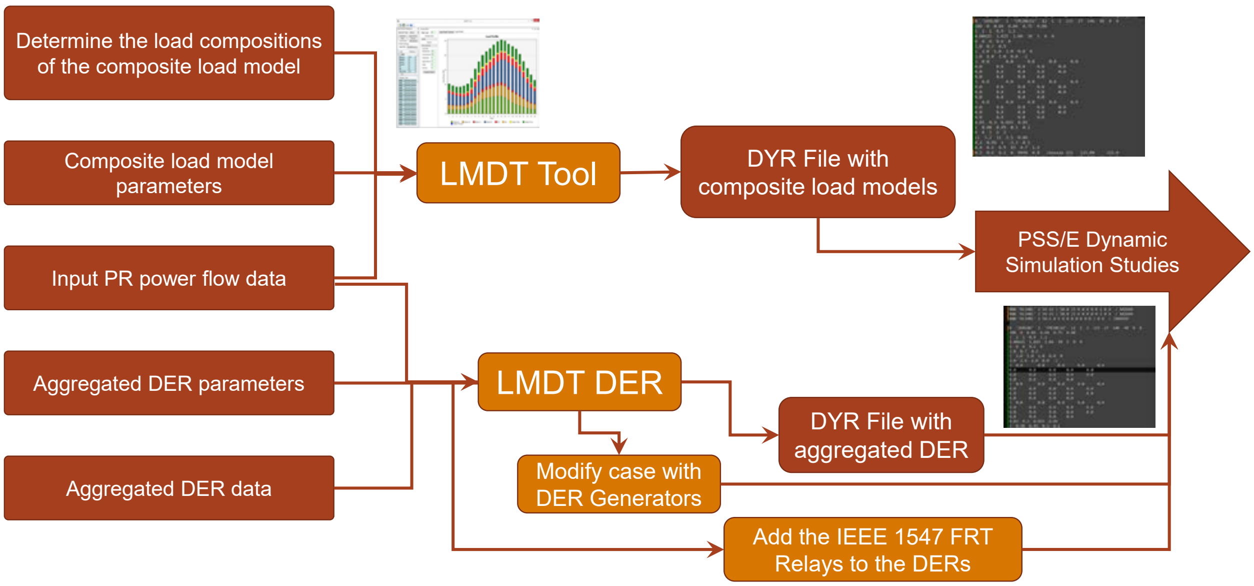

Figure 204. PSS/E model augmentation to include dynamic models for loads, DERs and FRT relays to capture inverter's FRT capability

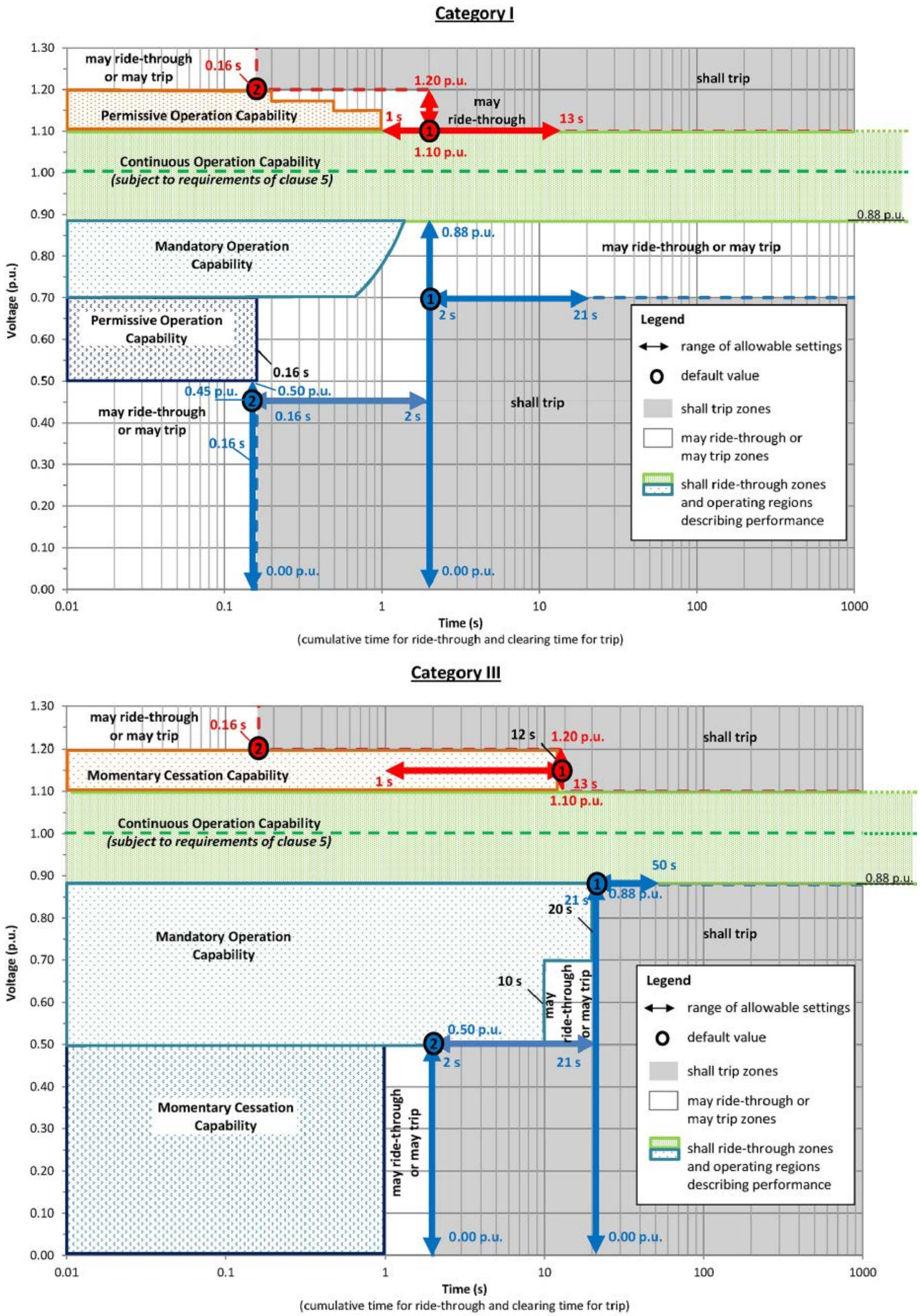

Figure 205. IEEE 1547 Category I and Category III voltage ride-through settings for DERs

IEEE (2018a)

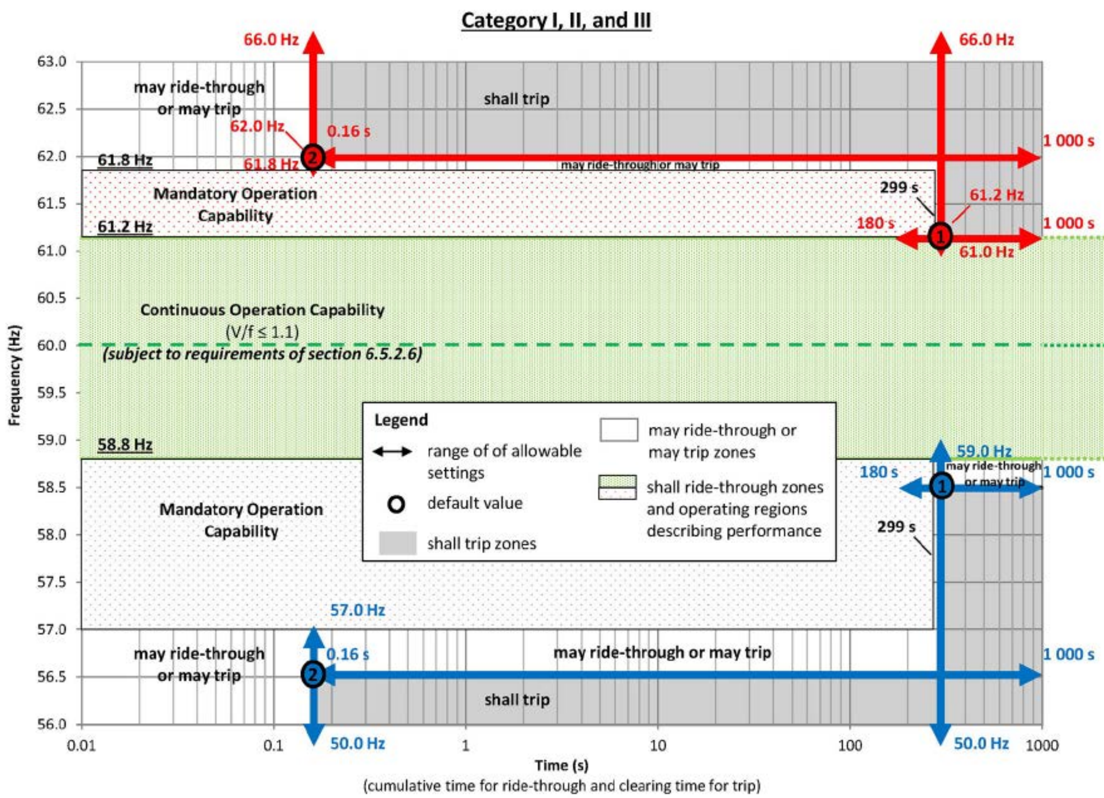

Figure 206. IEEE 1547 Category I, II, and III frequency ride-through settings for DERs

IEEE (2018a)

10.7.1.2.3 Importance of Modeling Load Dynamics

Load dynamics in the system are predominantly in the form of induction motor dynamic models that are included in the composite load model. For this study, 10% each of Motor A, Motor B, and Motor C are considered. And varying proportions of Motor D and static loads are studied to demonstrate the importance of considering the load composition accurately.

Voltage stability is defined as the ability of the system to maintain steady voltages at all buses in the system following a disturbance. Short-term voltage instability is primarily caused by large disturbances, such as faults, in the system. A classic case of short-term voltage instability is observed in the FIDVR, which has been reported by many utilities with a significant presence of induction motor load (Matavalam and Ajjarapu 2019; Robles 2015; WECC n.d.)

10.7.1.2.4 Simulation Setup and Study

A large disturbance in the system can be a short circuit fault, and default fault parameters are used to simulate a bus fault for 50 ms and cleared after it. The system models are updated with composite load models for all load buses with loads more than 5 MW of load and a voltage of at least 0.95 pu. A total of 168 composite load models are added in the system under study here.

The DERs are added in the system with the projections for a near future scenario. The total generation mix is a 100% inverter-based generation (100% instantaneous renewable penetration) with all energy storage generation being modeled with GFM inverter models and the PV generation being modeled with GFL generators. A total of 1,212 MW of DERs is added in the system. The 100% inverter case is also discussed in Section 10.6.1 (page 307) and the generation outputs for that case is shown in Figure 199, also in Section 10.6.1.

10.7.1.3 Results of Load and DER Stability Modeling

10.7.1.3.1 Fault-Induced Delayed Voltage Recovery

The system model is augmented with the dynamics of the loads and generation including DERs. A bus fault is simulated at t=1 s that lasts for 50 ms. The voltage response of the system is shown in Figure 207 for one bus in the vicinity of the fault location. An FIDVR event can last from 10 s to 35 s depending on the severity of the fault, load composition, and other factors.

Figure 207 also identifies the key parts of the voltage response in an FIDVR event. The time and the parts of the response also indicate the evolution of the load dynamics that cause the FIDVR event.

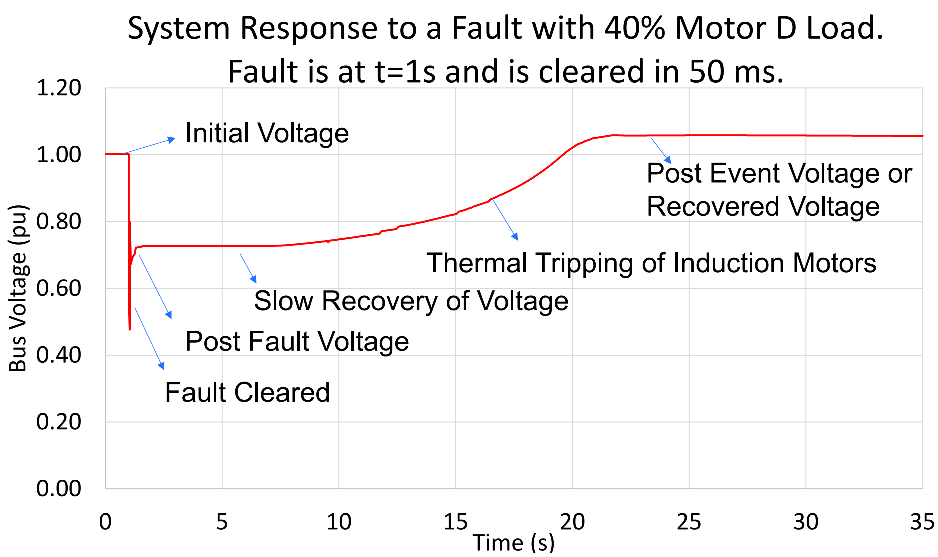

Figure 207. A FIDVR event for a bus fault with 40% $1-\phi$ induction motor load modeled through composite load models

The primary cause for FIDVR is stalling of induction motors in the system during and after a fault in the system. The induction motor stalling draws a large amount of real and reactive power in the system (3×–5× the nominal real and reactive power). Figure 208 shows how the motor power changes form the running condition to the stalled condition. The motor stalls if the voltage goes below 0.6 pu and remains stalled even if the voltage returns.

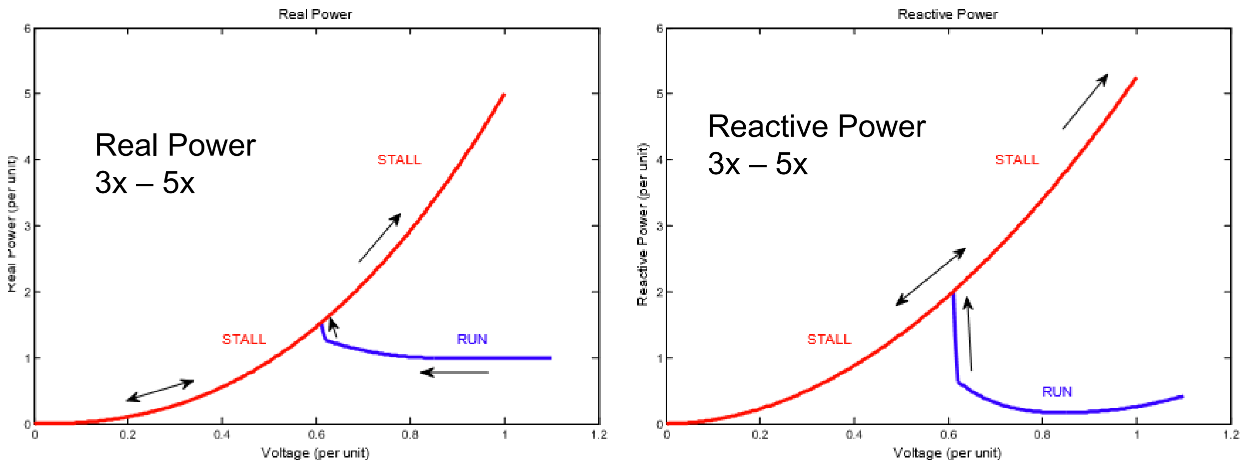

Figure 208. Active power (left) and reactive power (right) versus the voltage for the normal and stalled operation for the 1-ϕ induction motor

During a fault, the bus voltage for buses close to the fault goes below 0.6 pu, which stalls the induction motors. When the fault is cleared, the voltage tries to return to the prefault voltage, but as the motors have already stalled, the load in the system significantly increases. This phenomenon prevents the voltage from recovering quickly. The thermal relays of the induction motors kick in as the power drawn is 3×–5× the nominal real and reactive power. The thermal relays slowly start tripping the stalled induction motors, disconnecting the increased load in the system, which allows the voltage to start recovering. The thermal relays have some delay associated and so the tripping of the induction motors is not immediate. The recovered voltage is slightly higher than the prefault/initial voltage as post FIDVR, the load in the system is less due to the tripped induction motors.

Accurate voltage response to faults in the system can be captured only by modeling the dynamics of the lower voltage parts of the system accurately (load and DER dynamics).

10.7.1.3.2 Impact of Load Composition on FIDVR

Based on the above analysis of an FIDVR event, increasing the amount of Motor D ($1 - \phi$ induction motor) load in the system can aggravate FIDVR, and an illustration of this is given in Figure 209. In context of grid models for Puerto Rico, with its concentration of large amounts of air conditioners and simulations for operating scenarios corresponding to hot days, the system will benefit significantly in terms of accurate system responses by considering the dynamic models for loads and DERs. Therefore, modeling the load and DER dynamics accurately is important to capture realistic system responses so the system can be planned to account for such operating conditions.

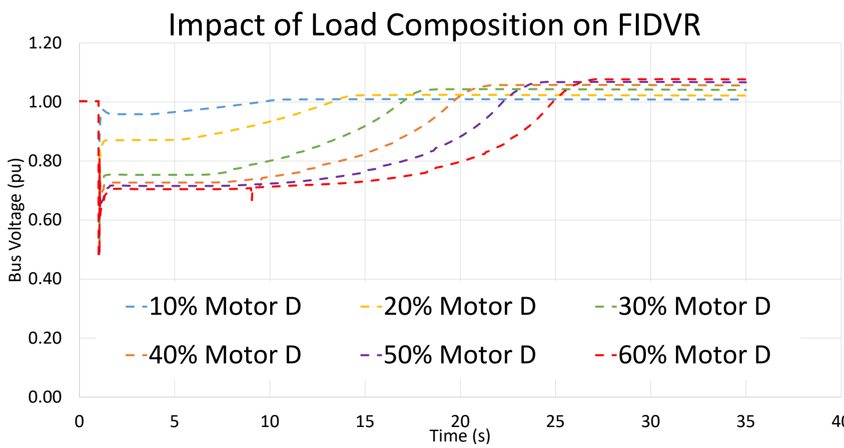

Figure 209. Impact of percentage of Motor D on FIDVR

10.7.1.3.3 Interactions Between Load and DER Dynamics with Inverter's IEEE 1547 FRT Capability

As discussed earlier, the system models are augmented with the dynamic responses of DERs along with the FRT relay models. The FRT relays are evaluated for both Category I (Cat 1) and Category III (Cat 3).

From Figure 210, it is clear that the DER FRT requirements and the FIDVR response of the system will interact, so modeling them together is important to realize the impact on the overall system response. The FRT relay models are added to the $1-\phi$ DER and all the DERs.

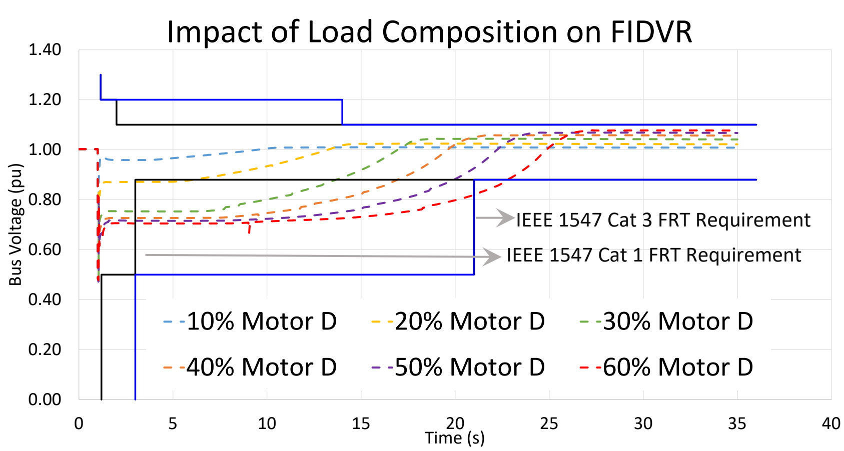

Figure 210. Overlap of IEEE 1547 FRT requirements and the FIDVR system response

For the same case of 40% Motor D in the system, Figure 211 and Figure 212 show how the DERs tend to trip during the FIDVR event, which further aggravates the voltage recovery in the system. Figure 212 provides the impact of Cat 1 FRT capability. The Cat 1 FRT settings are conservative settings that do not allow the DERs to remain connected and ride-through the fault. However, for bulk system support and allowing the DERs to ride-through the fault, Cat 3 capability settings will be very helpful. Figure 212 compares system responses with Cat 1 and Cat 3 of the FRT capability. With Cat 3 capability for 40% Motor D, no DER trip occurs during the FIDVR event and the DERs continue to provide full support to the system.

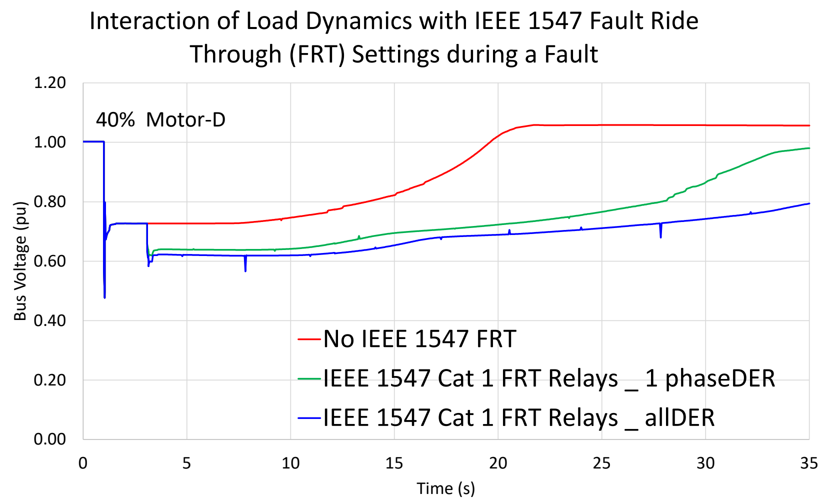

Figure 211. Interaction of load and DER dynamics with FRT capability

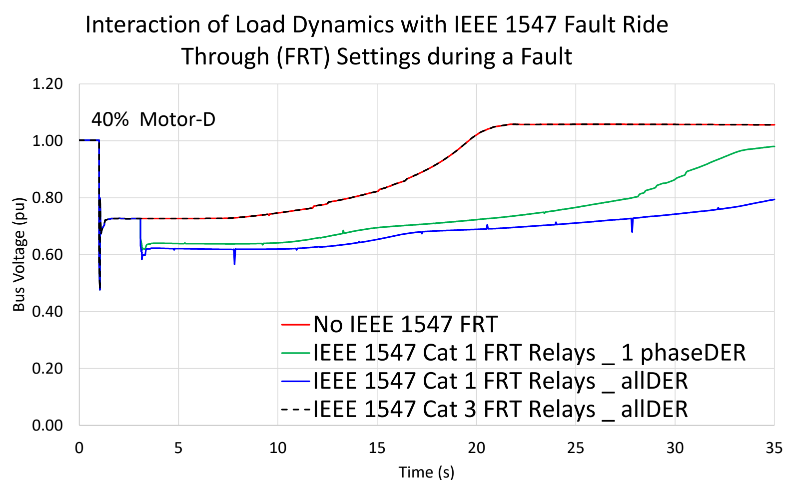

Figure 212. Interactions of load dynamics and DER IEEE 1547 FRT capability for Cat 1 and Cat 3

Cat 3 overlaps with curve for "no IEEE 1547 FRT" modeled.

10.7.1.3.4 Impact of Varying Load Compositions and DER's FRT Capability

This study deals with understanding the load composition variation and the IEEE 1547 FRT settings impacts on the overall system responses. Figure 213 shows the results for the varying percentage of Motor D present in the system along with different FRT relays models added to the dynamic DER models to capture inverter's FRT capabilities.

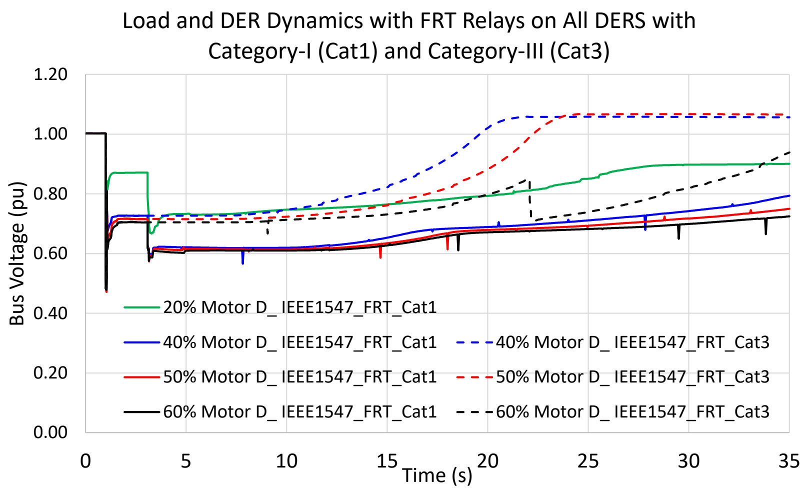

Figure 213. Impact of DER inverter's IEEE 1547 FRT capability for Cat 1 and Cat 3 with varying load compositions

From Figure 213, it can be seen that, for Cat 1 IEEE 1547 FRT capability (full lines in the figure), DERs trip, at about 3 seconds for all of the percentages of Motor D modeled, including the lowest of 20%. On the other hand, for Cat 3 IEEE 1547 FRT capability (dashed lines in the figure), DERs trip only for the highest percentage of Motor D (60%) studied, at about 22 seconds. The following observation are made:

- With IEEE 1547 Cat 1 capability, the DERs tripped during this FIDVR event for 20%, 40%, 50%, and 60% Motor D.
- With IEEE 1547 Cat 3 capability, the DERs did not trip during this FIDVR event for the 20%, 40%, and 50% Motor D. However, DERs trip for 60% Motor D.
- Cat 3 FRT settings allow the DERs to remain connected during a stressed condition and can help provide support to the system.
- For the highest percentage of Motor D studied, in this case 60%, Motor D caused the voltage to remain low for longer, causing the DERs to trip even with more robust Cat 3 FRT capability settings. This represents an extreme system condition for which the more robust Cat 3 capability settings are not sufficient to avoid aggravated situation in the system.

10.7.1.4 Considerations

Derived from the analysis using aggregated representation of motor loads and their interactions with DER, considerations for this section include that Puerto Rico:

- Consider accurate load compositions to model the load and DER dynamics to capture accurate system responses. Capturing the load and DER parameters will be important to make the system models accurate for planning and operational studies.
- Account for the protection models for all components of the grid. This study has shown the importance of considering IEEE 1547 FRT capability and modeling it along with the DER dynamics to capture the interactions among dynamic components in the system and thereby ensure a more accurate system response.
- Use Cat 3 FRT requirements for future DERs that are interconnecting to the Puerto Rico grid, which can be beneficial to the system. In the move toward inverter-driven loads like inverter-based air conditioners, variable frequency drive-based loads will help the system keep

FIDVR-related risk under control, as these kinds of loads do not allow for the induction motor to stall.

10.7.2 Transmission and Distribution Cosimulation: Assessment of IEEE 1547 DER FRT Settings With More Distribution Feeder Granularity

Solar, load management, electric vehicle, battery storage, and fuel-based DERs are expected to grow rapidly in Puerto Rico. This section focuses on the interactions of DERs and transmission networks, how DERs with IEEE 1547 passive controls may improve or exacerbate system recovery following a fault, and finally on the application of transmission and distribution (T&D) cosimulations to capture these interactions.

Standards are being updated to make DERs more grid friendly in many jurisdictions. In the United States and its territories, IEEE 1547 governs the behavior of most DERs during abnormal grid conditions. A version of IEEE 1547 created in 2003 (i.e., IEEE 1547-2003) requires DERs to trip immediately or closely following detection of voltage and frequency anomalies. IEEE 1547-2003 was appropriate when written and avoided the possibility of small quantities of DERs energizing lines and endangering linemen during outages. However, as DER penetrations increased, IEEE 1547-2018 was advanced, in part, to prevent wide-scale tripping of DERs during abnormal conditions. IEEE-1547-2018 has detailed requirements for abnormal voltage and frequency conditions and a range of implementation options. LUMA is in the process of adopting IEEE 1547-2018 Cat 3.

Several recent examples in the United States demonstrate the importance of adopting IEEE 1547-2018. In 2019, PJM identified prolonged voltage sag cases in north New Jersey that could trip approximately 1,000 MW of solar. DERs without ride-through (e.g., those following IEEE 1547-2003) negatively impacted all the voltage sag cases. The solution was to implement ride-through in solar smart inverters that follow IEEE-1547-2018. Similarly, in 2020, the Los Angeles Department of Water and Power speculated that solar DERs tripped and exacerbated FIDVR, as they observed that the recorded FIDVR behavior was inconsistent with transmission modeling (Wells 2021). And IBR tripping events occurred in Odessa, Texas on May 9, 2021, June 26, 2021, and June 4, 2022. Also, NERC key findings for the bulk grid are relevant to DER IBRs:

> "The risk profile for inverter-based resource performance issues needs to be elevated."
>
> "A comprehensive model quality review should take place."
>
> "Industry Not Sufficiently Implementing Recommendations from NERC Reliability Guidelines" (NERC and Texas RE 2021; 2022)

The remainder of this section describes (1) the motivation for using T&D cosimulations to study FIDVR events, (2) the modeling approach used by PR100 modeling team, (3) Puerto Rico cosimulations contrasting FIDVR recovery times for DERs with IEEE 15447-2003 and IEEE-1547-2018, and (4) future work.

10.7.2.1 T&D Cosimulation Motivation

Power system engineers need appropriate models to predict and mitigate system disturbances. A growing body of research suggests T&D cosimulations could be an important modeling tool for predicting DER impacts on abnormal transmission conditions (Kenyon and Mather 2020; NERC 2022; Rezvani et al. 2022). In short, T&D cosimulations may be needed because transmission models use aggregate, simplified representations of distribution networks, loads, and DERs.

Distribution networks have a great deal voltage diversity (i.e., variation in voltages throughout the network) caused by control equipment (e.g., capacitors and load tap changers), and varying conductor impedances, especially on secondary circuits where DERs and motor loads are located. Transmission models represent distribution networks using *composite* load models with a single impedance. Figure 214 (left) shows the voltage profile for a realistic distribution network model compared to the transmission composite load model representation. Furthermore, LUMA currently uses a utility-scale, or U-DER_A model that assumes DERs are placed near the substation. These U-DER_A models do not have any voltage diversity. The DER_A (i.e., aggregate DER) model released in 2019 (EPRI 2019) is also a simplification of IEEE 1547-2018. An illustration of key differences between IEEE 1547-2018 and the DER_A model is shown in Figure 214 (right). It displays the low-voltage and high-voltage ride-through regions of IEEE 1547-2018 Cat 1 in detail. The purple region shows an approximation of how IEEE 1547-2018 Cat 1 DERs are represented in the DER_A model. In short, the application of DER_A models on LUMA's transmission models might not accurately capture the response of DERs to transmission faults because the DERs will see different voltages and will follow different rules than the DER_A model.

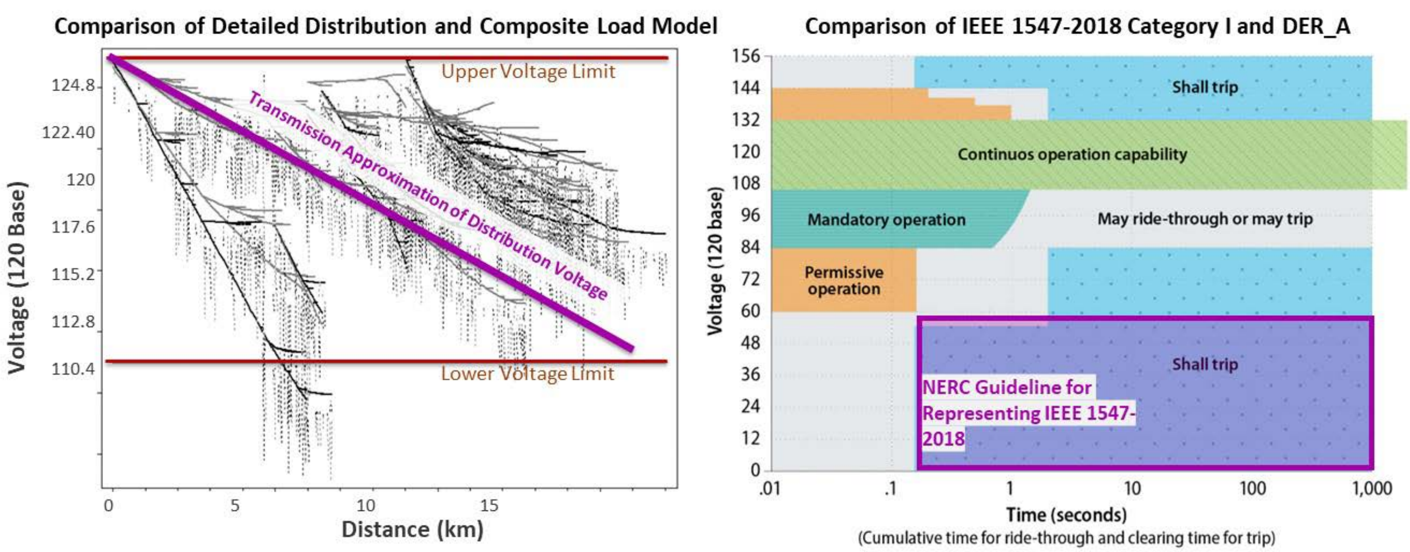

Figure 214. Comparison of aggregate and detailed models used for distribution networks and DERs

10.7.2.2 PR100 T&D Cosimulation Modeling Approach

Figure 215 describes how T&D Dynamic cosimulations are used to model system disturbances. First, a fault occurs on the transmission bus, which causes the voltage to sag. PSS/E, the transmission simulator, publishes the voltage and the distribution model subscribes to the voltage. Then, PyDSS, the distribution simulator, runs a three-phase unbalanced power flow to determine the voltage throughout the distribution network. These higher fidelity voltage calculations allow better estimates of how the distribution network's power consumption changes, particularly from DERs and motor loads, which are very sensitive to voltage. Finally, PyDSS exports the substation power consumption to PSS/E.

To reduce validation efforts, only DERs and load models are ported to the distribution model because they are highly dependent on voltage diversity. The Motor D air conditioning loads, as referenced in Figure 215, are ported to the distribution side because motor stalling is highly dependent on voltage. Furthermore, stalling causes a large amount of reactive power consumption, which can affect transmission system dynamics. In the T&D cosimulation, a voltage-dependent motor model is used (W. Wang et al. 2018) with the stall voltage set to 66 volts (120 volt base) and disconnect times that range from 10 s to 20 s.

Likewise, the DER voltage ride-through model highly depends on voltage diversity, as shown in Figure 214 (right). Detailed 1547-2018 DER models are used in the T&D cosimulation.

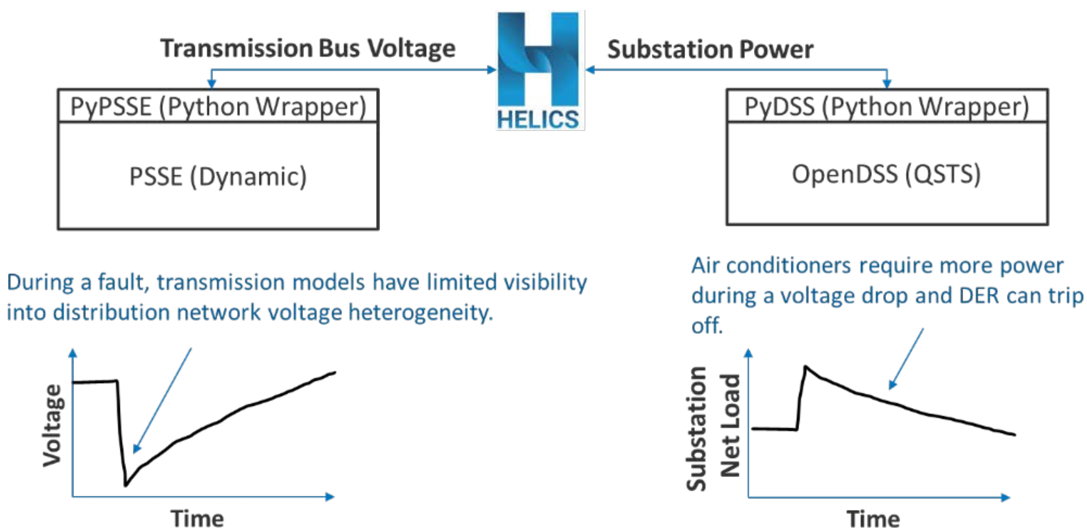

Figure 215. Key steps in T&D cosimulation

Source: Keen et al. (2022)
QSTS is quasi-static time-series.

The cosimulation process described in Figure 215 can yield erroneous results if the loads and DERs are not carefully calibrated to be consistent with the equivalent transmission models. For example, if the total load and load power factor on the distribution model is inconsistent with the transmission model, differences between the cosimulation and "transmission-only" results will reflect the inconsistency. And the model will not accurately capture the effects of including the full voltage diversity of distribution networks.

Figure 216 provides details on how we set up the cosimulations and ensure consistency between the T&D models. First, one time-step of a dynamic cosimulations is run to initialize the model. Static real and reactive power, bus impedance, dynamic load model parameters, and DER parameters are extracted. Next, the transmission bus is split into two buses. The first bus keeps all parameters that will *not* be ported to the distribution model, and the second bus keeps all parameters that *will* be ported to the distribution model. Combined, the two buses are equivalent to the transmission bus before the split. During a cosimulation, the load and DER models in the second transmission bus are disabled because they will be represented more accurately by the distribution network. The disabled transmission bus subscribes to power from the distribution simulator and uses a "constant power" load model to ensure the power is not further affected by voltage.

Additionally, some calibration steps are needed to ensure the distribution model is equivalent to the Transmission Bus 2. First, the transmission bus impedance from the DER_A model is used for the source impedance in the distribution network. Second, an optimization routine is run that adjusts the distribution real and reactive power loads until the distribution source power factor is the same as the transmission bus power factor. Third, DERs on the distribution network are revised to match the transmission network. Fourth, scaling factors are calculated that scales the distribution real and reactive power published by PyDSS to match transmission loads. This last step is typically needed because distribution models do not exist for every transmission load bus.

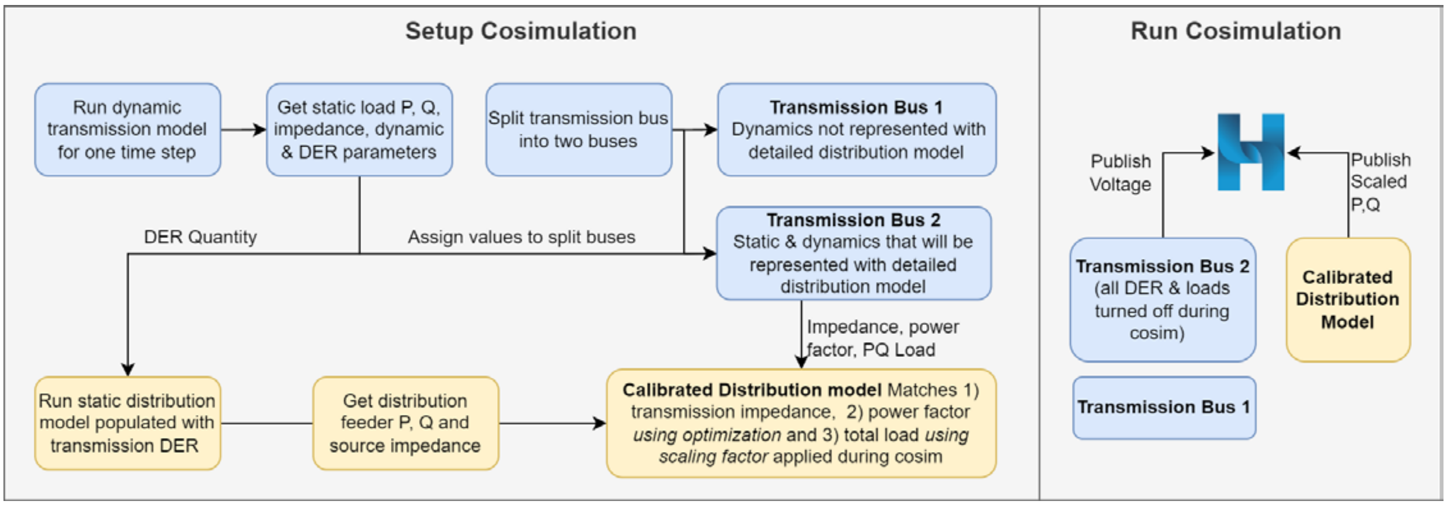

Figure 216. T&D cosimulation setup

10.7.2.3 PR100 T&D Cosimulation Results

Figure 217, Figure 218, and Figure 219 show the results for a cosimulation between the Puerto Rico transmission network and a representative Puerto Rico distribution network. The transmission network for the 1LMNet scenario is used. Faults ranging from 10 ohms to 20 ohms are applied at Transmission Bus 96. The distribution network model (number 7601) is from the Camuy municipality. The transmission network is cosimulated with the Camuy distribution network model at buses 89, 90, 91, 92, 104, and 105. These locations were chosen because they are close to the fault bus, have composite load models, and have aggregate DER models. When interpreting the results in this section, it is important to note that the cosimulation includes both aggregate load and DER models, and detailed distribution models. Future work may include cosimulations with different distribution models and cosimulations at more transmission buses to fully show the impact of T&D cosimulations.

Figure 217 compares FIDVR response for DERs with IEEE 1547-2018 and IEEE 1547-2003. After 35 s, the mean voltage on distribution networks with IEEE 1547-2018 is 106 volts (120 base), and the mean voltage on distribution networks with IEEE 1547-2003 is 92 volts (120 base). This difference is not negligible. Voltages below 100 volts are likely to damage customer equipment and appliances.

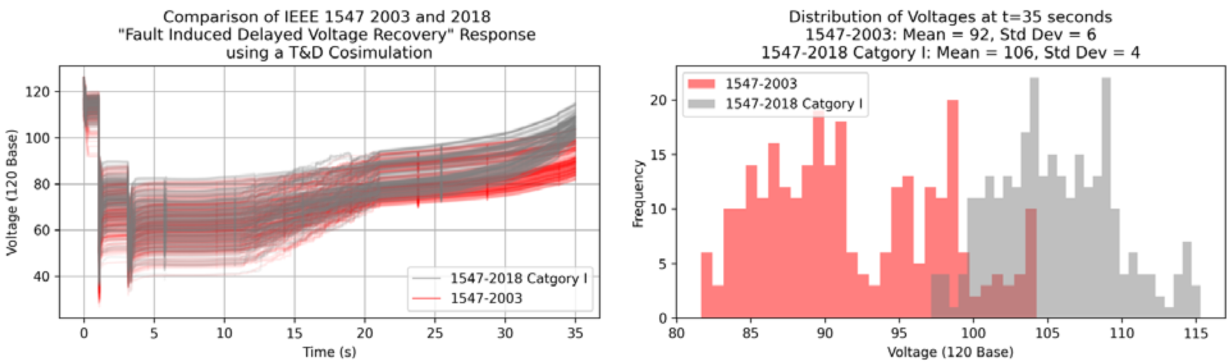

Figure 217. Comparison of IEEE 1547-2003 and IEEE 1547-2018 FIDVR using T&D cosimulation

Figure 218 compares FIDVR responses using the transmission model and the T&D cosimulation. The left chart of the figure shows a FIDVR response with a 10-ohm fault. The response for the transmission simulation and T&D cosimulations are similar; the primary difference is that the T&D cosimulation better reflects realistic levels of voltage diversity (i.e., variation in voltages on the distribution network). However, the right chart, where a 20-ohm fault is applied, shows that a single parameter change (i.e., the fault impedance) can lead to dramatic changes in the conclusion for the transmission simulation. In this case, the transmission simulation voltage does not go low enough to trigger motor stall behavior and does not predict a FIDVR event. In contrast, some of the T&D cosimulation voltages do go low enough to trigger motor stall behavior and cause a FIDVR event. These results do not imply T&D cosimulations must be used to mitigate against FIDVR events, but rather they show the value of T&D cosimulations for improving the parameterization and robustness of transmission models.

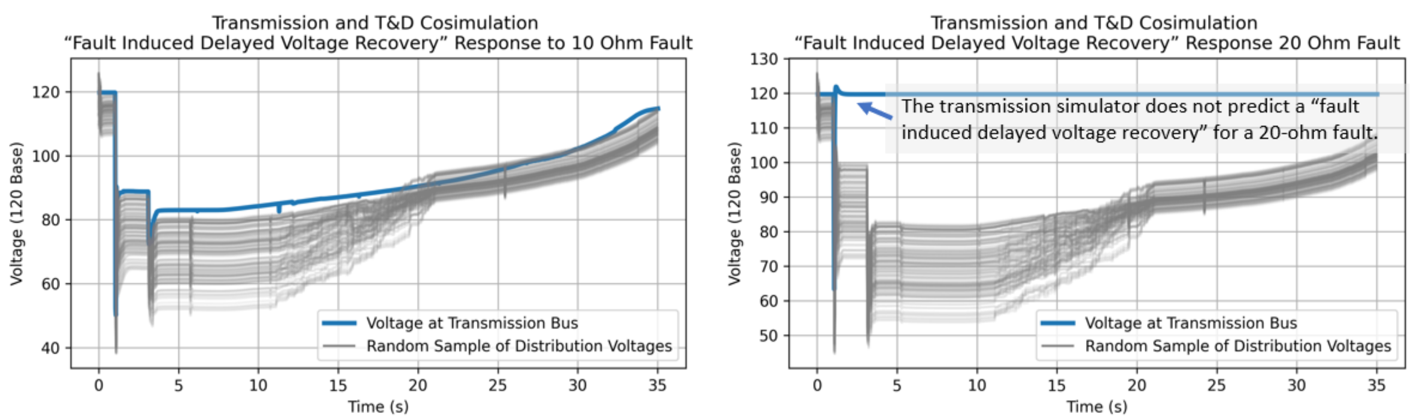

Figure 218. Comparison of FIDVR using only a transmission simulation and using T&D cosimulation

Figure 219 shows the detailed DER (left) and motor (right) models used in the T&D cosimulations. The fault occurs at 1 s. This causes most DERs to enter momentary cessation and most motors to stall. After 0.4 s, the DERs recover but eventually disconnect because the voltage remains low. The motors continue stalling and begin disconnecting between 12 s and 22 s.

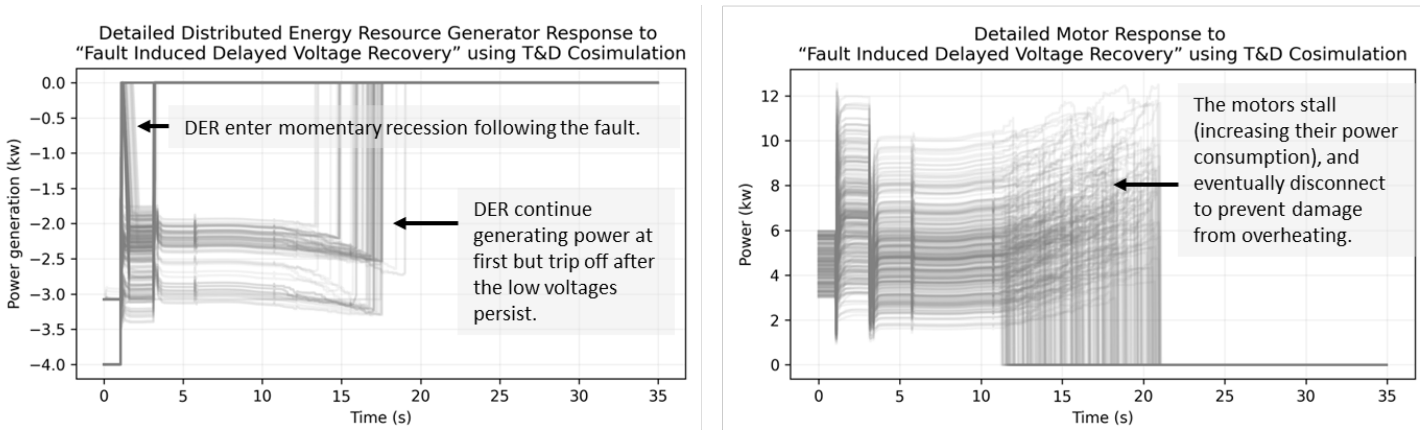

Figure 219. DER generator and motor response to FIDVR

10.7.2.4 Considerations

Considerations from T&D cosimulation to analyze loads and DER stability impacts include that:

- Pursuing several opportunities can improve the reliability of Puerto Rico transmission networks. Most importantly, adopting IEEE 1547-2018 would help the transmission network recover from a range of disturbances. This is partially shown in Figure 217, where DERs with IEEE 1547-2018 help improve the FIDVR recovery time. Irrespective of FIDVR events, DERs following IEEE 1547-2003 typically begin tripping for voltages as high as 106 volts. This behavior, alone, could cause reliability issues if Puerto Rico had high penetrations of DERs. Refining models offers another opportunity to improve the reliability of Puerto Rico's transmission network, as several potential modeling improvements could be made.
    - First, the composite load models used in the transmission models may not reflect customer loads. In PR100, a 40% Motor D (i.e., air conditioning load) penetration is assumed. This motor penetration is conservative and may lead to more severe FIDVR events than would actually occur.
    - Second, utility-scale aggregate DER models are used, which assumes DERs are directly connected at the substation. This utility-scale DER assumption could result in models that underestimate the impact of DERs tripping. "Residential" aggregate DER models are now available that capture some of the voltage drop that occurs on distribution networks.
    - Third, aggregate DER and load models all make simplifications, and it is not well understood how these simplifications affect the accuracy of modeling results in high-DER-penetration scenarios. T&D cosimulations can be used to study the impact of aggregate DER simplifications and to suggest improved implementations of the aggregate DER models.
    - T&D cosimulations can also be used to study the impacts of several 1547-2018 features, including primary frequency response, dynamic voltage response, and the use of volt/var and volt/watt settings.

10.7.3 Considerations

Considerations for system stability with load and DER dynamic modeling include that Puerto Rico:

- Perform additional studies of current air conditioning load composition, which will be beneficial to understand the potential for FIDVR to cause reliability concerns currently and in the future.
- Adopt VFD air conditioners that could help avoid the motor-stalling effect that potentially causes voltage instability. VFD are a current industry trend including for new air conditioning systems in Puerto Rico, but there can still be legacy air conditioning equipment in Puerto Rico.
- Ensure DERs robustness to voltage deviations will benefit system reliability. The IEEE Standard 1547 (IEEE 1547) (IEEE 2018b) Category III FRT settings proposed by LUMA should be followed to avoid unnecessary disconnections during and after transmission faults.
- Use robust settings for low- and high-voltage ride-through capabilities in utility-scale renewables and battery storage that will benefit reliability by avoiding unnecessary disconnection of generation.
- Implement real-time high-resolution grid measurement systems (phasor measurement units) and associated communication infrastructure to facilitate various reliability and stability enhancement activities, like generation and storage model validation, contingency event investigation, including FIDVR, DER tripping, oscillations and resonance, as well as real-time situational awareness.

10.8 System Black-Start Using Grid-Forming BESS

Modern BESS inverters, available from many vendors, can be procured with an option of having GFM controls combined with black-start capability. Many wind turbine and PV inverter manufacturers are working on similar controls as well. NREL conducted simulations to demonstrate how central BESS plants can energize LUMA 230-kV and 115-kV transmission systems, establishing the voltage and frequency for the whole grid in Puerto Rico, allowing IBR-based generation to synchronize with the grid and participate in system restoration process after hypothetical territory-wide blackout. These simulations were conducted on a tuned-up model of LUMA grid using generic GFM inverter models.

Soft-start control for GFM inverters is a useful option that allows avoidance of large inrush currents when energizing transformers, segments of transmission lines, and large motor loads (i.e., oversizing inverters for black-starts is not needed). This feature, which is commercially available from different inverter vendors, allows ramping of voltage from zero to a rated level, thus eliminating inrush currents. Soft-start controls have been tested by NREL using utility-scale GFM BESS at the NREL Flatirons Campus. Validated soft-start model is used PR100 to simulate different strategies for energizing different segments or entire transmission system by a large central GFM BESS plant. Strategies, considered in this study, include:

- **Strategy 1:** A large central GFM BESS provides consecutive energization of segments of transmission system, thus allowing designated PV plants to start and provide power to loads.

- **Strategy 2:** A large central GFM BESS energizes the whole transmission system, with all loads and generators being disconnected, thus allowing system operator to start coordinated system-wide restoration process.

10.8.1 Strategy 1 Example

In this example, a 250-MVA GFM BESS plant connected to the Aguirre substation bus energizes segments of transmission grid, allowing the connection of loads with simultaneous start of designated PV plants (Figure 221). Results of simulations for this example are shown in Figure 220.

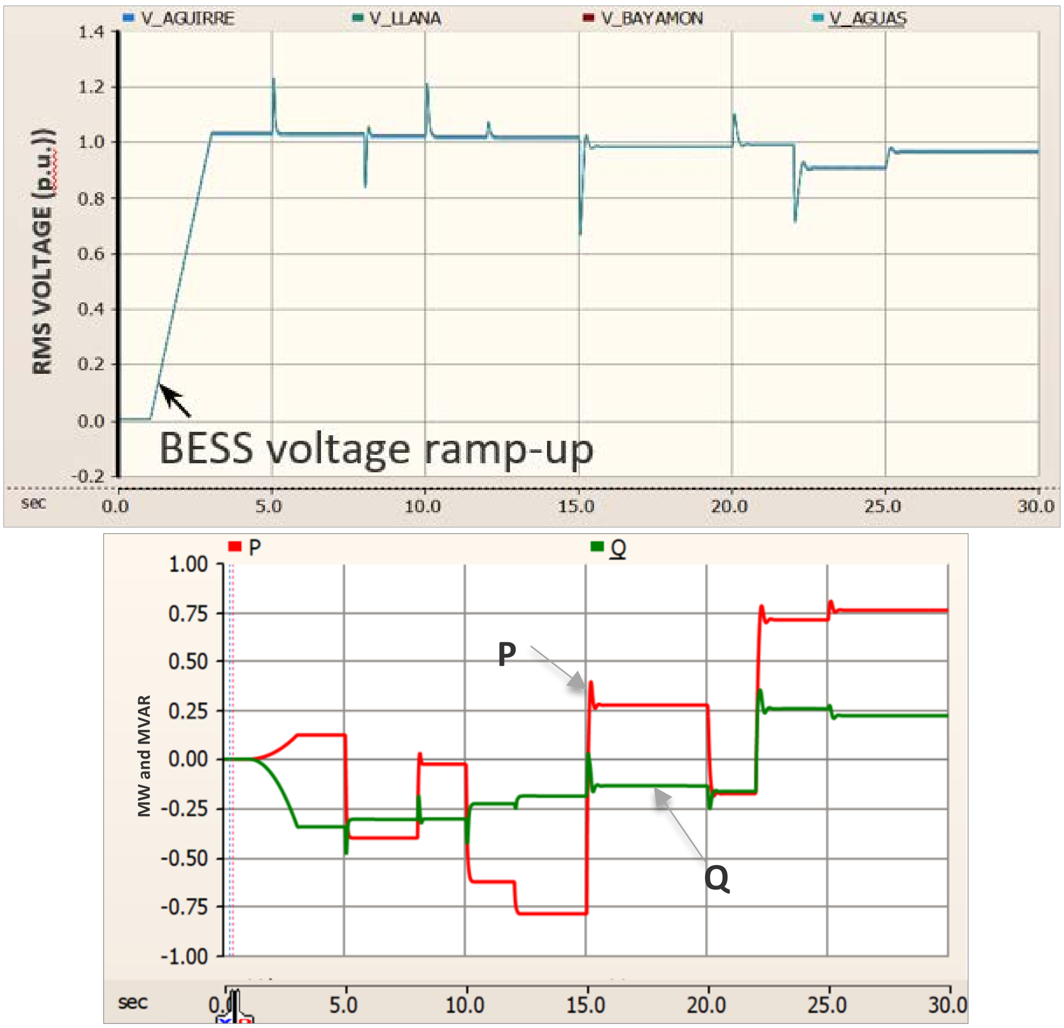

Figure 220. Simulation of black-start energization of 230-kV transmission segments from single BESS

Voltage at various 230-kV buses, active (P) and reactive power (Q) at BESS.

Short time intervals between each action are used to reduce simulation time:

1. A 250-MVA GFM BESS energizes transmission grid in the areas shown in Figure 221.
2. At T=1 s, soft-start control is activated, BESS voltage ramps up to the rated level energizing designated substations and transmission lines.

3. At T=5 s, PV Plants 1 and 2 start producing power and charging BESS, and at T=8 s, breakers are closed to energize designated loads in the area.
4. At T=10 s and T=12 s, PV Plants 3 and 4 start producing power and charging BESS
5. A 200-MW load is energized in the San Juan area.
6. At T=20 s, PV Plants 5 and 6 start producing power.
7. At T=22 s, another 200-MW load is energized in the San Juan area. At this time, voltage sag is observed in the system that is eliminated by changing the BESS voltage set point at T=25 s.

GFM BESS and substation voltages, BESS active and reactive power during the whole process are shown in Figure 221.

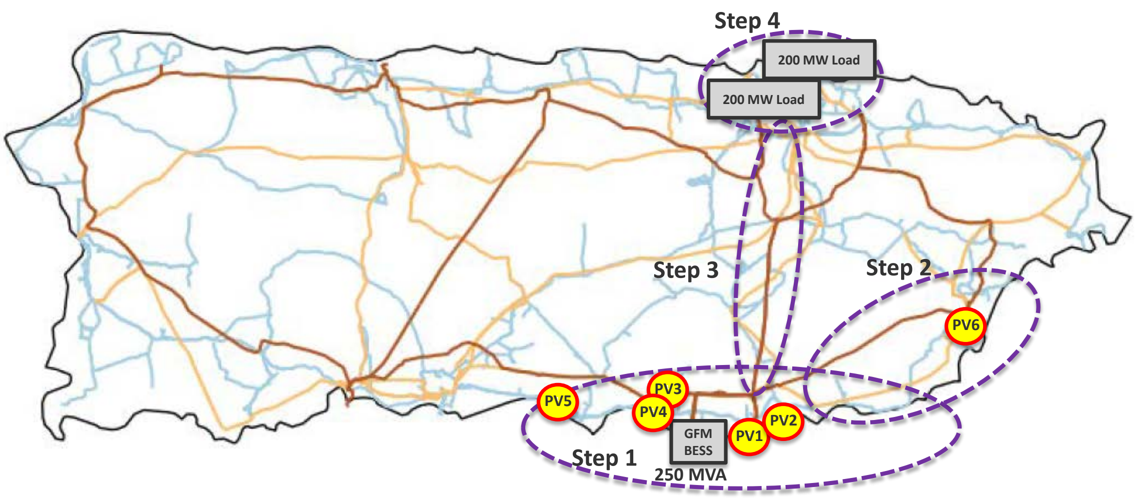

Figure 221. Black-start with consecutive energization steps

Dashed lines indicate areas included in the black-start process.

10.8.2 Strategy 2 Example

In this example:

1. A 250 MVA GFM BESS with soft-start control is used to energize the entire transmission grid with only substation loads. All network loads and generator are disconnected.
2. Transmission line capacitance generates some level of reactive power that is absorbed by GFM BESS to prevent excessive voltages in the system.

Simulation results for Strategy 2 case are shown in Figure 222 and Figure 223 (page 334). Stable voltage and frequency are established in the entire transmission network, allowing the system operator to start a coordinated energizing procedure for generating plants and most critical loads.

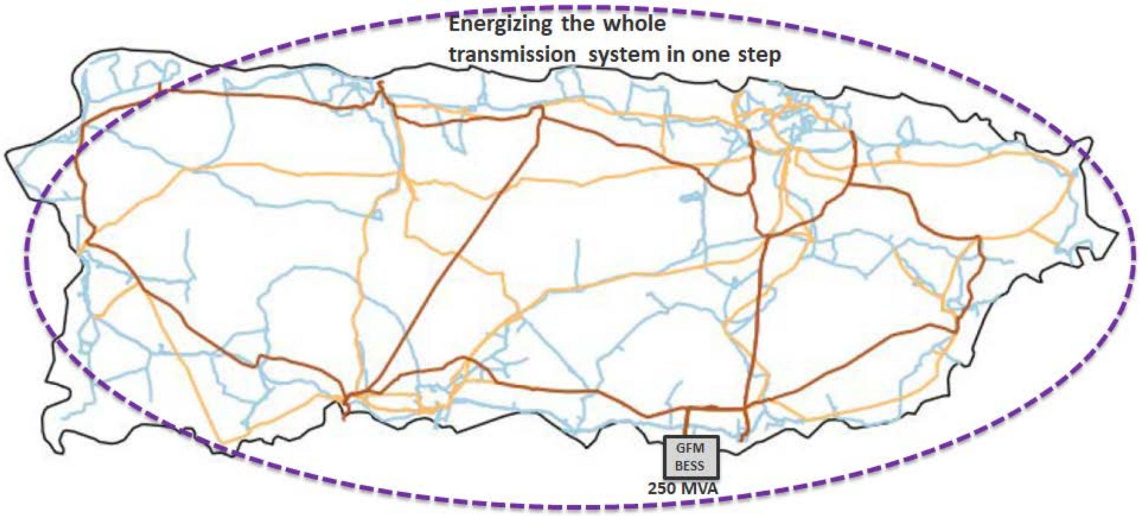

Figure 222. Energizing the entire transmission network by one step with all loads disconnected

Other black-start strategies are possible, too. The above examples demonstrate how large GFM BESS plants can be used to restore the system after a territory-wide blackout or after a system separation caused by a natural disaster or other event. With proper black-start procedures for each of the tranche scenarios, the system can be restored in a quick and robust manner, thus increasing the resiliency of Puerto Rico grid.

10.8.3 Considerations

Considerations about black-start of GFM BESS include that Puerto Rico:

- Ensure technology and controls for BESS to participate in black-starts are available in Puerto Rico.
- Implement pilot projects for utilizing black-start and grid-forming control from BESS in the near term.
- Develop and research solar and wind power generation participation in black-start process and implement pilot projects.

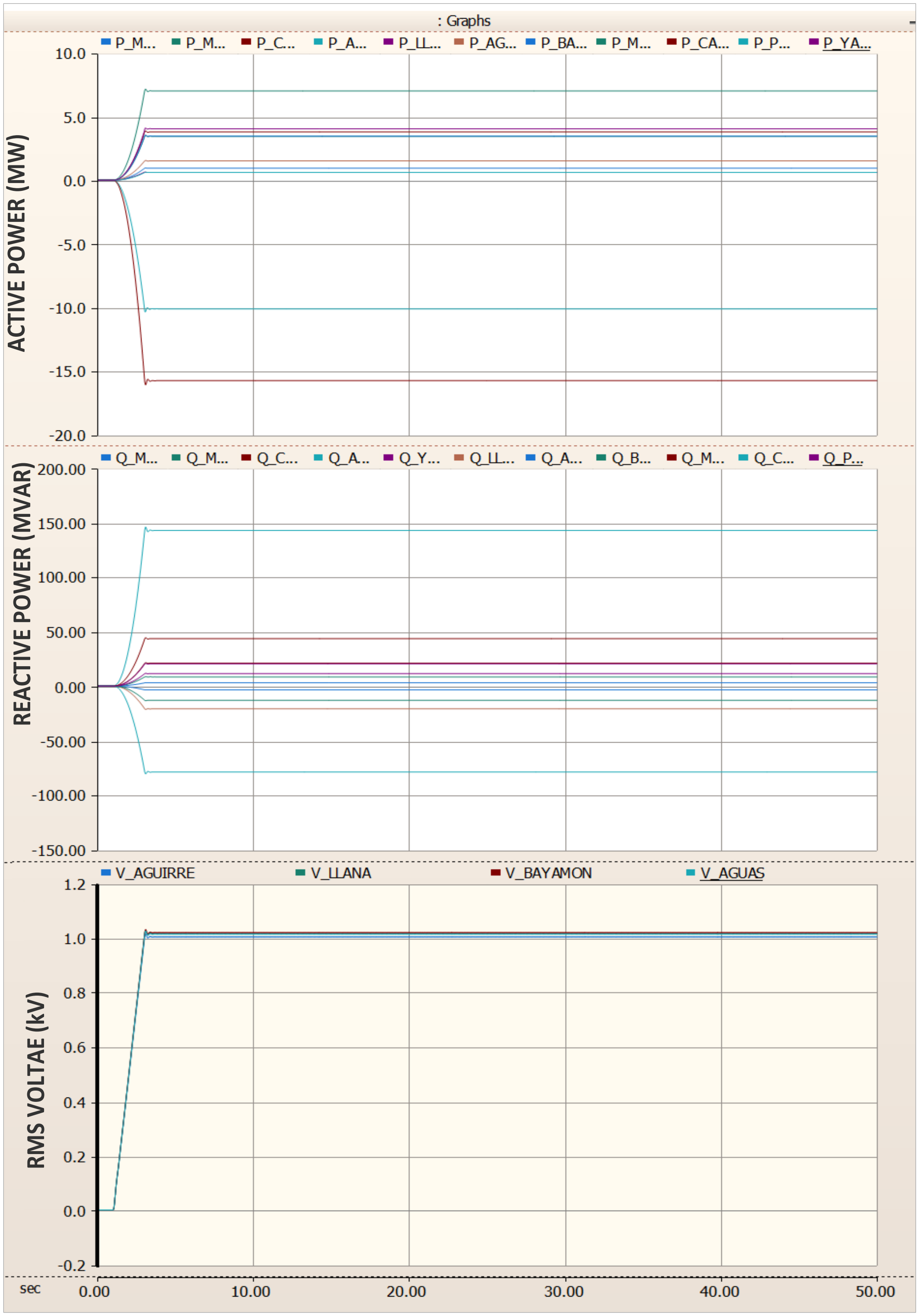

Figure 223. Energizing the entire transmission system with GFM BESS: Active (upper graph) and reactive (middle graph) power, system voltages (lower graph)

10.9 Resilience Analysis

This subsection covers two types of resilience analysis, probability of failure of infrastructure caused by high wind hazard and grid recovery modeling after severe damage. Both modeling activities center in planning aspects.

It is important to note that there has been limited validation activities of the models used in this section, and PNNL continues to incorporate more data and improvements into the models. The probability of failure from transmission assets from Hurricane Maria data is reported in reference (Bereta dos Reis et al., 2022), and there is ongoing validation work of probability of failure of distribution networks. Additional model improvements are ongoing at the time of publication of this report, using analysis of new data from Hurricane Fiona. Additionally, the model incorporates data from infrastructure design and construction in consultation with engineers from Puerto Rico. The models used in this section should continue to be improved and validated as more data becomes available from more events and from system upgrades.

10.9.1 Modeling Hurricane-Related Probability of Damage to T&D and Solar Generation Infrastructure

Models to capture the probability of damage to electric infrastructure are incorporated in PNNL's Electrical Grid Resilience and Assessment System (EGRASS). These models are used to generate sequences of infrastructure failure that are then used in grid simulation tools to analyze the impact to the power grid from hurricanes. EGRASS was also used to analyze probability of failure from utility-scale PV and rooftop solar PV.

The main findings of the damage simulations are as follows:

- T&D infrastructure is still prone to damage from hurricanes.
- Utility and rooftop PV would suffer minor damage when new installation standards are used.
- Two utility-scale PV plants were damaged with Hurricane Maria, but one plant designed for high wind (160 mph) and elevated for flooding (2–4 m) was not damaged.
- Stakeholders interviewed indicated that minor damage was observed in rooftop PV systems.
- EGRASS simulations for 30,000 systems with 140 mph and 180 mph new standards confirm that damage in less than 1.2% of the systems is expected from high wind, and that damage can be concentrated in areas where hurricane makes landfall.
- Since Hurricane Maria, Puerto Rico has adopted new standards for T&D infrastructure to design for 160 mph wind. However, there is still legacy T&D infrastructure designed for lower wind speed. EGRASS simulations estimate failure of this legacy infrastructure that then are used to study grid recovery with PNNL's Recovery Simulator and Analysis (RSA) tool. Preparation and planning should continue to manage legacy T&D infrastructure as it gets rebuilt to the new standards.

10.9.1.1 Electrical Grid Resilience and Assessment System

PNNL's EGRASS is a mature enterprise grade computational framework, built using Amazon Web Services-specific cloud first principles and deployed in a production caliber environment that provides an outward-facing intuitive interface for stakeholders and sponsors for accessing analytics from domain experts. Development began in 2018, following Hurricane Maria, and has evolved over the last five years with increasing capabilities and application to emergency preparedness and disaster response planning. This capability has vastly improved efficiencies in collaborating within the national laboratory and with and between the national laboratory and collaborators. EGRASS is accessible via a web-based interface as a tangible dynamic product which can be customized and calibrated with specific scenarios and natural hazard events.

Moving from on premise to cloud in 2018, the EGRASS framework was designed embracing Amazon Web Services (AWS) platform as a service, or PaaS, and serverless to the extent possible, largely bypassing "lift and shift" migration. This led to significant improvements in scalability and redundancy. Throughout the evolution of EGRASS and various instances, the team developed infrastructure as code, dramatically improving our time to deployment and instantiation.

EGRASS primary requirements and development objectives have been guided by LUMA, serving as the principal product owner. The power and efficiency of the framework lies in systematically streamlining complex data processing functions, integrating, and hosting these capabilities as stand-alone APIs in AWS. In EGRASS, this process involves simulating historic and predicted hurricane wind intensities and quantifying the impact on electric grid assets, such as towers, substations, and solar panels. At present, this capability is being expanded to include other natural hazards such as floods, heavy rainfall, and landslides. After assessing the impact on electric grid assets by natural hazard events, EGRASS auto generates input files for PSS/E models and other tools used in conjunction with risk assessment.

EGRASS has a rich database layer and abstractable data modeling component that accounts for diversity of data types and is extended to include geospatial datatypes and complex geospatial analytics. A significant amount of data preprocessing was necessary to develop spatial referential integrity and reconcile knowledge gaps with respect to grid topology (Royer et al., 2022; Li et al. 2023).

10.9.1.2 Probability of Damage of PV Generation and T&D Infrastructure

A central tenant of EGRASS is developing and deploying dynamic event-based probabilistic models and fragility curves and integrating this logic into a seamless end-to-end workflow (Elizondo et al., 2020; Barrett et al., 2022; F. Bereta dos Reis et al., 2022). EGRASS has integrated this for Hurricanes Maria 2017, Irma 2017, Grace 2021, and Fred 2021. EGRASS has also characterized failure probability for future scenarios, accounting for increases in radiative forcing, working with PNNL RAFT team (K. Balaguru 2021). EGRASS uses hurricane best track data from National Hurricane Center as a geographic reference point and to extract observed windspeed along hurricane path. Windspeed is used to dynamically generate a wind field layer to the extent of wind swath from which maximum windspeed is calculated at each asset. Using the maximum observed windspeed, fragility curves are estimated for various electric grid assets, including towers and solar panels (Figure 224 and Figure 225). T&D infrastructure damage is simulated in EGRASS and used in the recovery simulations of Section 10.9.2 (page 339).

A comprehensive set of data sheets were reviewed from different solar/PV manufacturers and installers to understand the build standards that these installations are designed for specifically for rated wind gust speeds that the installations can bear. The important finding is that most manufacturers and installers use the standards laid out in the "Minimum Design Loads for

Buildings and Other Structures” by American Society of Civil Engineers 7-10 (ASCE/SEI 7-10) [ASCE, 2013] and shown in green in the Figure E2, in addition to two lower standard older designs (Goodman 2015; Watson 2020) also shown in the figure. For Puerto Rico the requirements were upgraded to be able to withstand 180 mph (shown in red in Figure 2) after Hurricane Maria. Figure E4 shows the failure probabilities of all solar installations (rooftop as well as utility-scale PV) in Puerto Rico for the Hurricane Maria simulation using the fragilities shown in Figure E2 and the maximum wind speeds an illustration of which is shown in Figure E3 for transmission towers in Puerto Rico. Notice that the solar installation right where Hurricane Maria made landfall (which is the south-eastern corner of the main island) has the highest failure probabilities (between 10% to 35% shown in shades of red in Figure E4) and they start approaching zero as we move further inland. It is important to mention that overall, less than 1.2% of 30,000 PV systems simulated in EGRASS are expected to suffer damage.

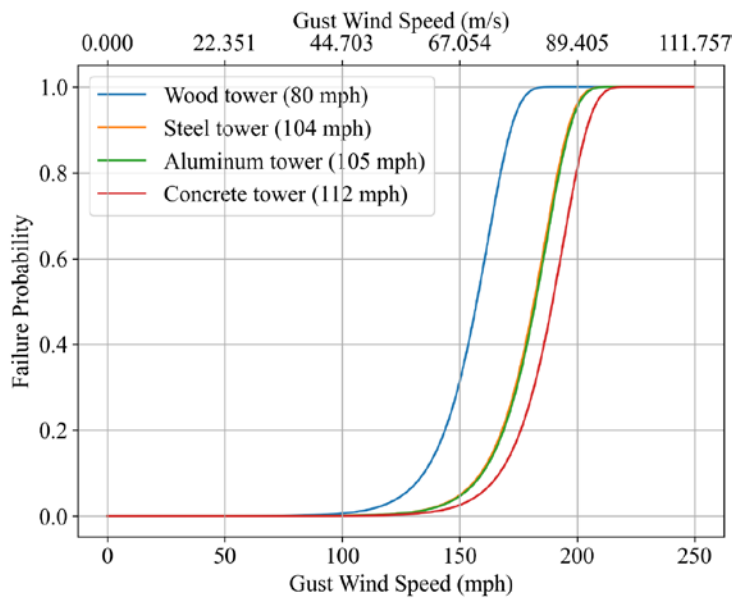

Figure 224. Fragility curves for electrical towers

Bereta dos Reis et al. (2022)

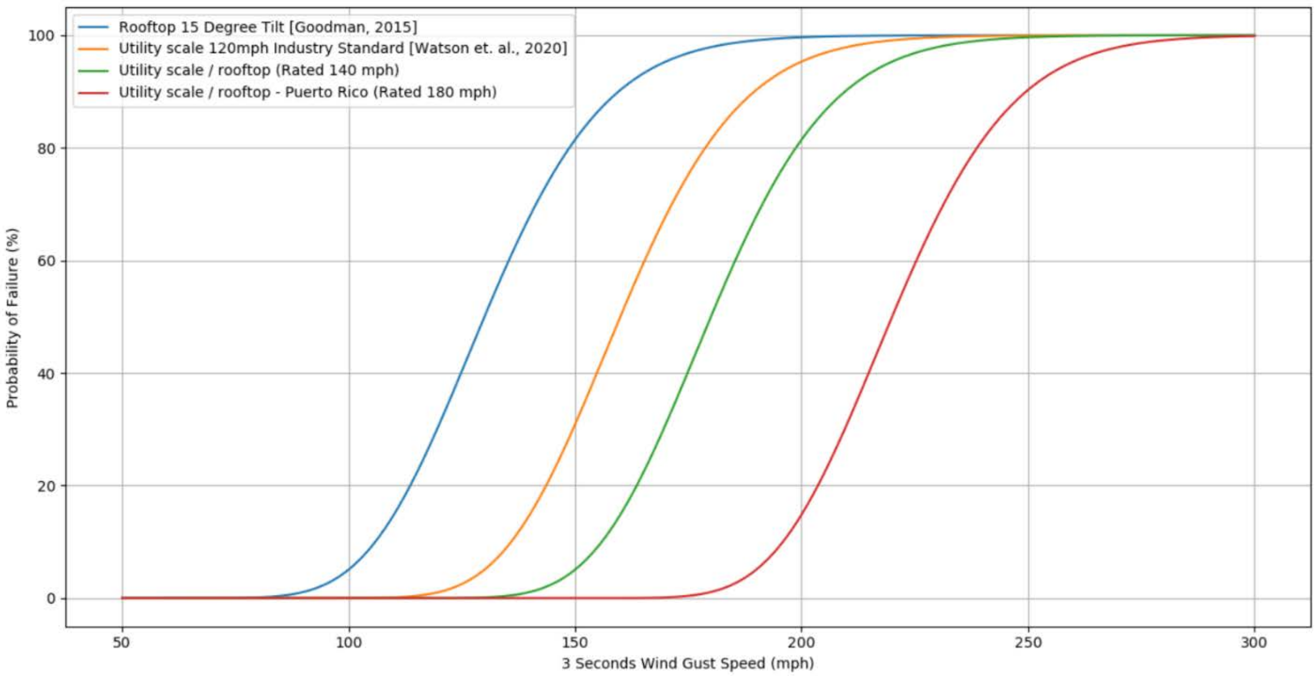

Figure 225. Fragility curves for rooftop and utility solar

Figure 226. Maximum wind gust speeds subject to transmission towers across the main island

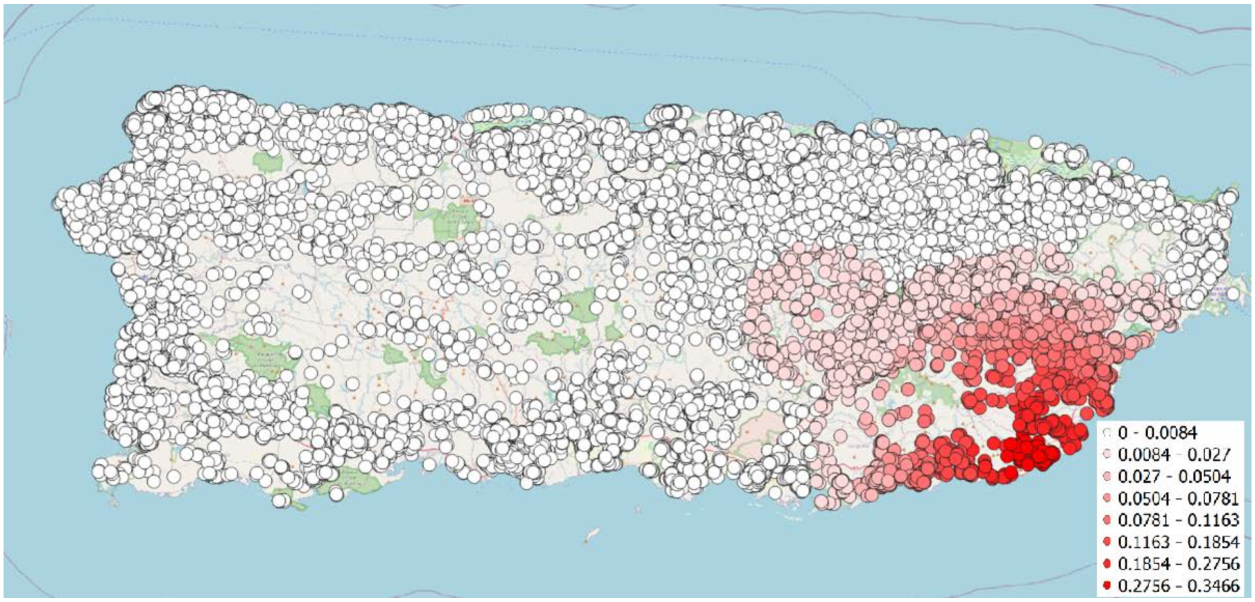

Figure 227. Probability of failure for solar installations (rooftop and utility-scale) for Hurricane Maria simulation

10.9.2 Simulations of Grid Recovery From Hurricane-Related Severe Damage

This section presents a transmission and subtransmission resilience analysis based on estimation of severe damage to infrastructure and power system recovery simulations for 100 hurricanes. The analysis aims at using recovery simulations as a planning application to evaluate future configurations of Puerto Rico's grid. The evaluation focuses on how, in certain system configurations, it could be easier or harder to recover the grid after severe damage. The analysis uses PNNL's EGRASS and RSA tools. EGRASS estimates infrastructure damage based on extreme weather stressor inputs and probability of damage to the infrastructure, and RSA estimates the level of time and effort to recover and fix the electric infrastructure after severe damage.

The results of this analysis highlight that, generally, recovery after hurricanes can potentially be better for cases with more DERs if all resources participate in recovery process. A change of paradigm is required for renewables (DER and utility-scale) and BESS to participate in recovery (which implies GFM and black-start capability is required).

The results also indicate transmission, subtransmission, and distribution recovery to supply 90% of the load is similar for the 2028 case with maximum and economic DER adoption (3LS scenario) and the 2028 case with economic DER adoption (1LS scenario). Further study and optimization of location and sizing of utility-scale solar and wind generation as well as location and sizing of energy storage could improve the resilience analysis results.

The results also show that the profile of the last 10% of load to be recovered is better for the 2028 case with maximum DERs (3LS scenario) than with the case with economic DER adoption (1LS scenario). Also, the initial unserved load, at the beginning of the recovery simulations, is lower for the case with maximum DERs.

10.9.2.1 Methodology for Recovery Simulations After Severe Damage

The purpose of PNNL's RSA tool (P. Maloney et al. 2023) is to simulate the order of asset recovery that most rapidly reduces unserved load on the electric power grid following a disaster such as Hurricane Maria. To simulate the recovery of the electric power grid following a hurricane, RSA uses the status of "outaged" assets provided by EGRASS to determine the initial state of the grid. The RSA simulation is then broken up into discrete steps, each of which has a budget corresponding to the number of transmission lines that can be recovered or the amount of labor that can be expended in that time-step. To measure recovery time and effort, units of work crew days are used, which correspond to the days it would take a fully equipped work crew to recover an asset. The optimization then determines the combination transmission, subtransmission, and feeders, which is subject to the budget constraints and physics of DC power flow, which minimizes underserved load in every time-step.

A flow chart of the recovery inputs and procedures is given in Figure 228. As can be seen in the figure, RSA uses as inputs simulations of hurricane-related damage estimations to transmission, subtransmission, and distribution infrastructures from EGRASS. EGRASS estimates damage in infrastructure using extreme weather stressors from hurricanes, such as high wind, and models of the probability of failure of infrastructure to weather stressors (Royer, Du, and Schneider 2022; Elizondo et al. 2020).

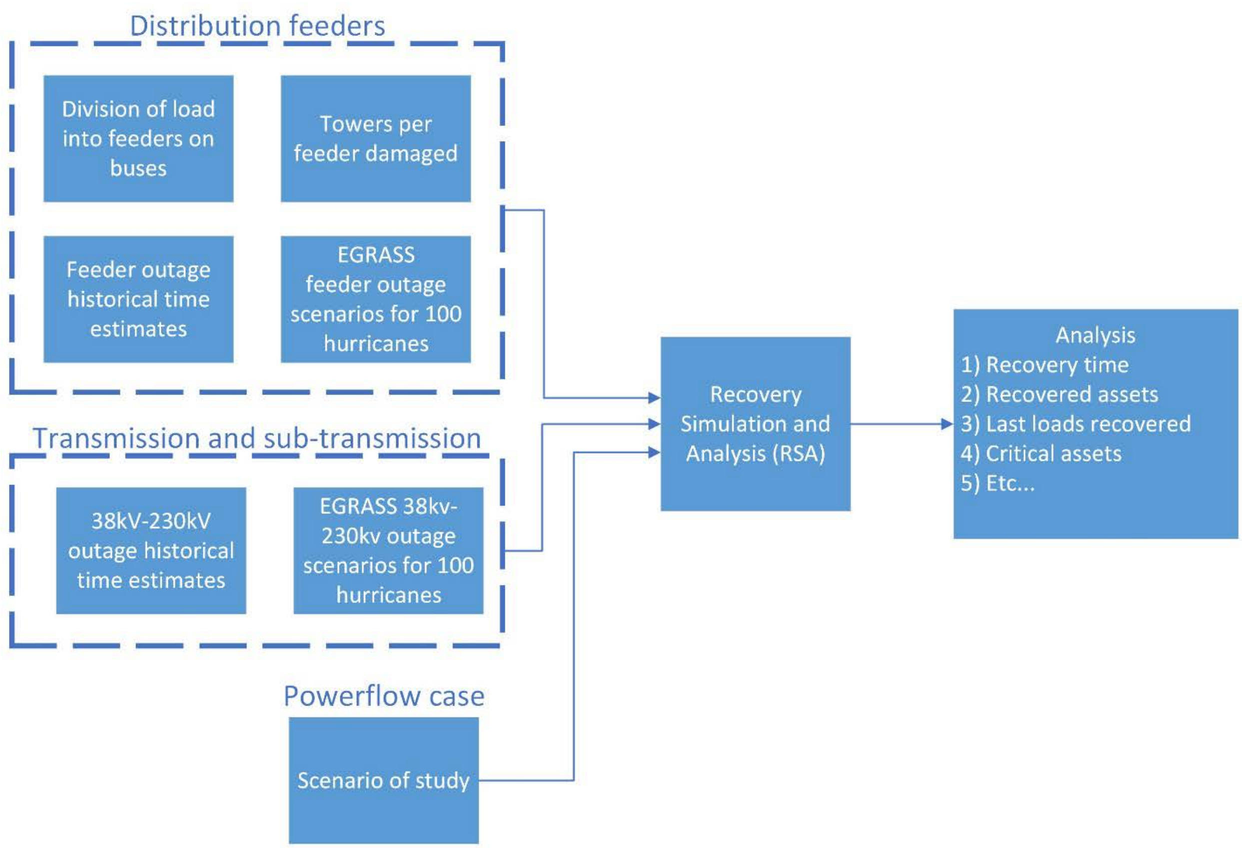

Figure 228. Flow chart of PNNL's RSA tool inputs and outputs

The main outputs of RSA for each hurricane scenario include:

- Cumulative recovery times in work crew days (Work crew days divided by the number of work crews working in parallel gives the expected recovery time days.)
- The transmission, subtransmission and feeders recovered in each time-step
- The location and amount of served and unserved load.

All power flow data can also be extracted from RSA, but typically the above outputs are used in the bulk of the output analysis.

10.9.2.2 Results of Resilience Analysis Based on Recovery Simulations

The results shown in Figure 229, Figure 230, Figure 231, and Table 37 synthesize the simulated recoveries across 100 scenarios for two separate capacity expansion planning buildouts in the year 2028.

- The 3LS scenario corresponds to a higher DER build-out (≈3 GW) and higher forecasted load (≈25,220 MW afternoon peak).
- The 1LM scenario corresponds to a lower DER build-out (≈1 GW) and lower forecasted load (≈2,820 MW afternoon peak).

Currently RSA is designed to simulate recovery around a peak loading condition which is selected as 8/7/2028 at 4 p.m. While this is not the actual peak load, it represents a high loading condition during the day when solar can still contribute to the recovery. In both cases all scenarios limit renewable generation output to production costing models simulated dispatch. Thermal plants, however, are free to dispatch up to their maximum capacity.

It is important to note that RSA model considers that utility-scale and distributed solar generation and energy storage contribute to the system recovery. And particularly, RSA assumes that DER (rooftop PV and storage) remains connected and help during recovery process, which include black-start. This assumption implies a change in paradigm in technology for these resources to participate in grid recovery, because currently, it is not standard for utility-scale renewables and DER to participate in grid recovery. The technology is mature for utility-scale BESS to participate in black-start and recovery as well as for renewables and BESS to form microgrids; on the other hand, there are currently research and development projects on the use of DER and utility-scale renewables to participate in grid recovery and black-start. Therefore, the assumption in RSA represents an advanced state of the technology application and standardization.

The next subsection (Section 10.9.2.3, page 343) highlights result for grid recovery simulations for scenarios with more DER (3LS) and less DER (1LM), and with different deployments of utility-scale resources. The different location and deployment of generation and DER affect the recovery process as the optimization procedure in RSA[147] would make different decisions in the order of system fixes for recovery. In general, having generation and storage resources in more locations benefits the system recovery process.

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[147] See Section 12.8.2.1 for a high-level description of RSA and references (P. R. Maloney et al. Submitted; Meng Zhao et al. 2023) for details on how RSA implements optimization

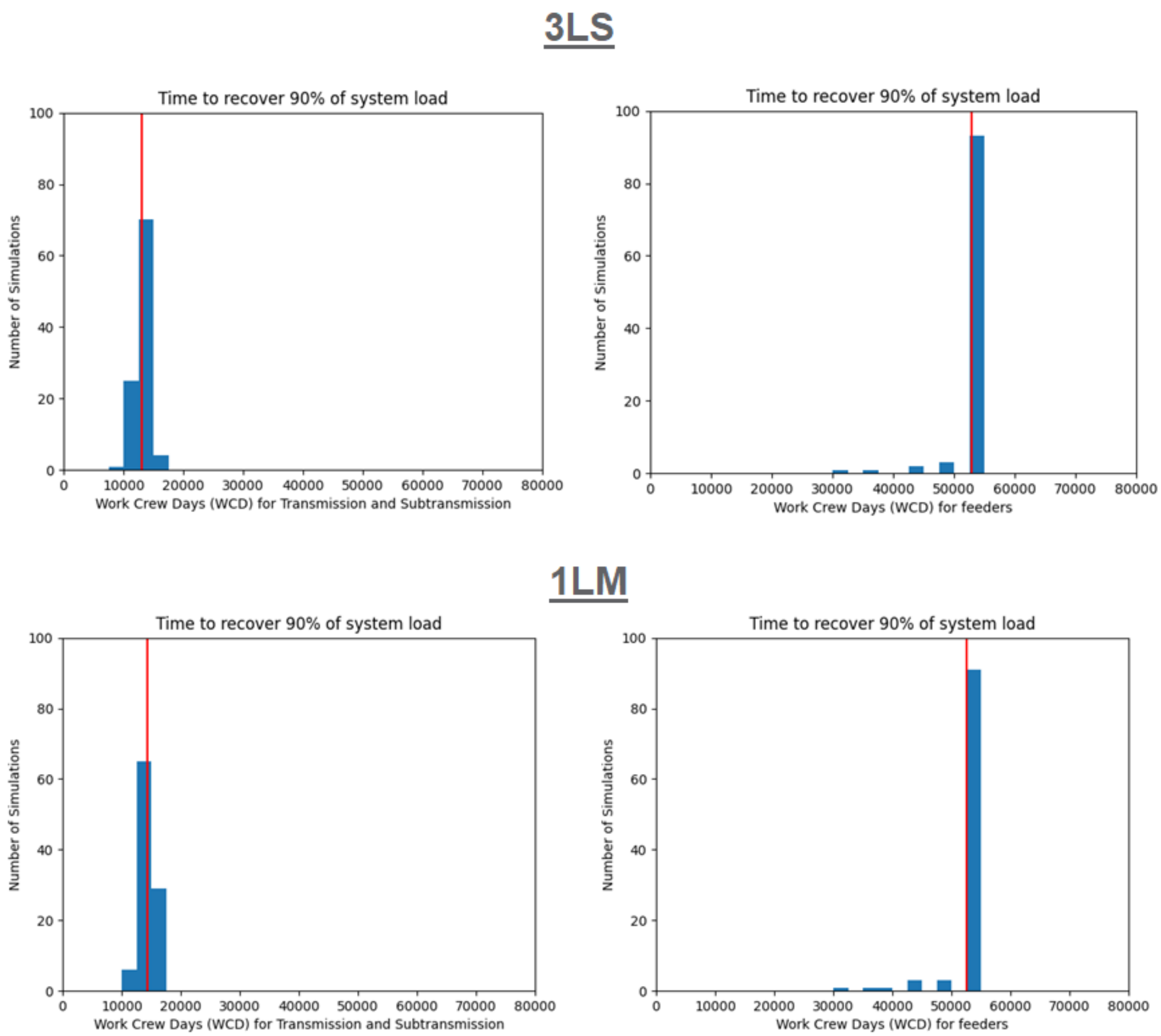

Figure 229. Time in work crew days to recover 90% of system load in 3LS (top) and 1LM (bottom)

Red line indicates average.

Table 37. Tabulated Average Recovery Times (work crew days) from Figure 229

Asset	**3LS**	**1LM**
Transmission and subtransmission	13,082	14,291
Feeder	52,827	52,604
Cumulative	**65,909**	**66,896**

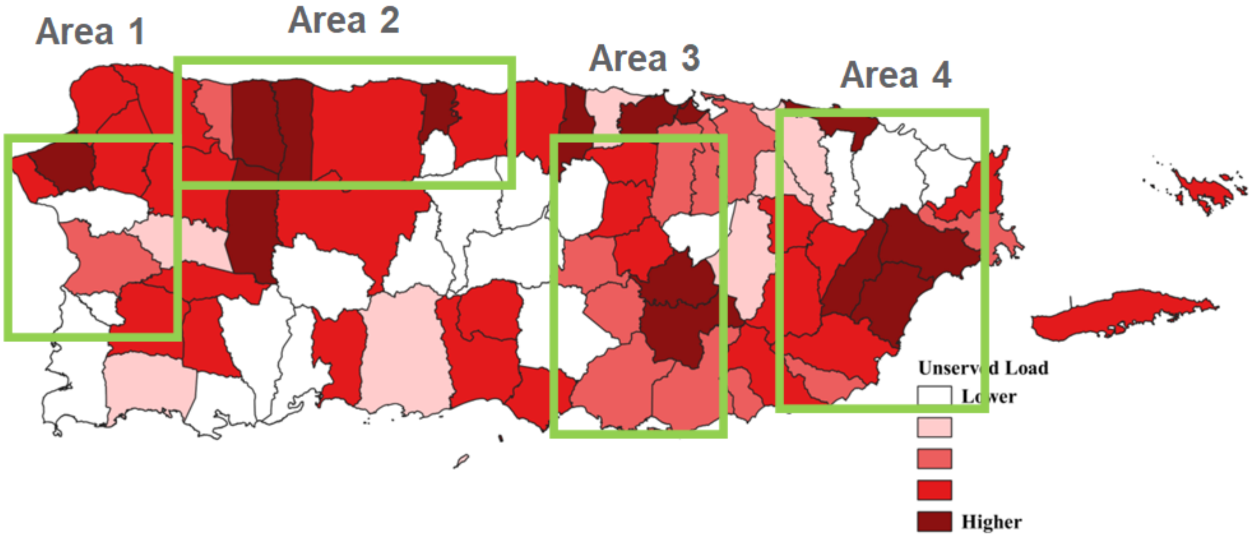

Figure 230. 3LS locations of last 10% of unserved load as a percentage of load in each region

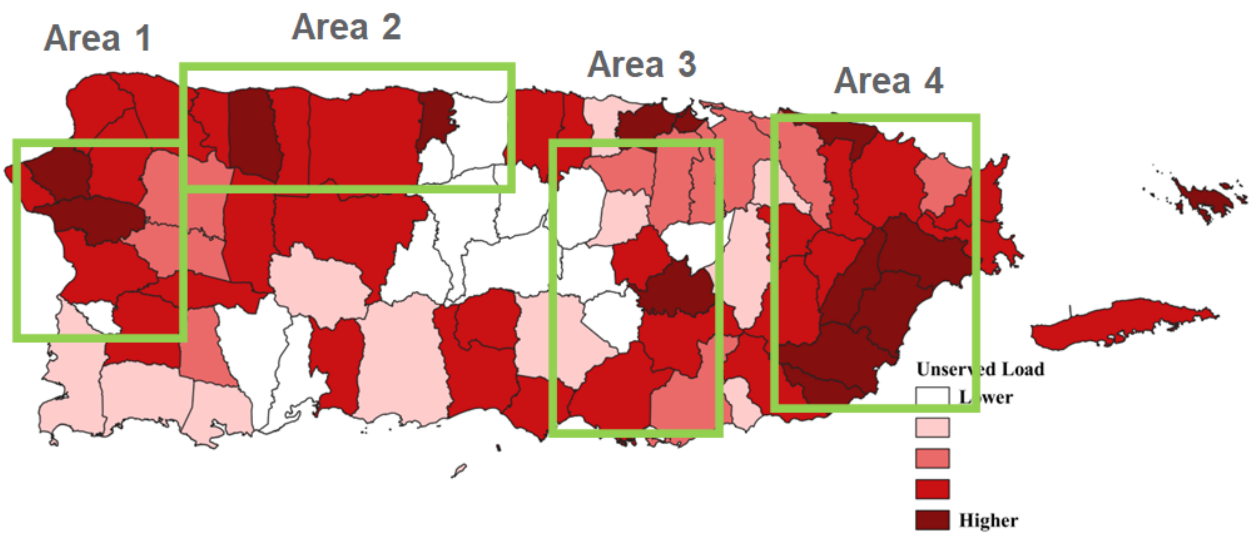

Figure 231. 1LM locations of last 10% of unserved load as a percentage of load in each region

10.9.2.3 Summary of System Recovery Simulations

While the 3LS and 1LM scenarios have similar recoveries in terms of recovery time, and Table 37 Figure 229 shows that 3LS tends to recover faster than 1LM across the 100 scenarios by ≈1,000 work crew days. Prior results have tended to show that more distributed renewable buildouts tend to result in faster recovery times.[148] This is likely because load can be served almost immediately without needing to recover transmission to connect to centralized power stations. However, as Figure 232 and Figure 233 show, generation sites for 3LS and 1LM for wind, solar, hydropower, and batteries are almost at identical locations between the two scenarios in 2028 with the main difference being the size of these units. As shown, with the

[148] "Research Team Creates New Resilience Analysis Tool for Grid Recovery," Courtney Stenson, PNNL, November 7, 2023, https://www.pnnl.gov/publications/research-team-creates-new-resilience-analysis-tool-grid-recovery.

exception of a single location, the green 3LS units tend to be larger, despite being at the same location. The cumulative capacity of dispatchable renewable and storage generation in 3LS and 1LM is approximately 2,494 MW and 2,023 MW respectively.

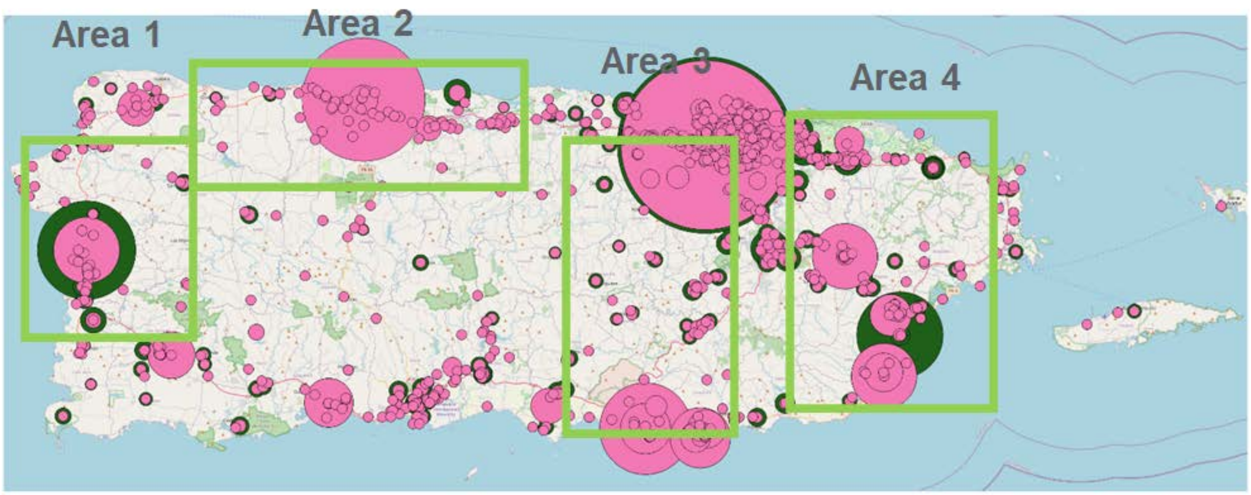

Figure 232. Layers show generation locations of wind/solar/hydropower and batteries in 2028 where size is related to (but not proportional to) the available capacity allowed for the two different scenarios.

3LS generation is green, and 1LM generation is pink. Pink 1LM layer placed on top of green 3LS layer.

Figure 233. Layers show generation locations of wind/solar/hydropower and batteries in 2028 where size is related to (but not proportional to) the available capacity allowed for the two different scenarios.

3LS generation is green, and 1LM generation is pink. Pink 1LM layer placed below green 3LS layer.

While the renewable generation and batteries are of similar size in 2028, the magnitude of the differences between the two appears larger in 2040 (Figure 234 and Figure 235) which may result in larger recovery time differences if recovery simulator where to be run in these years.

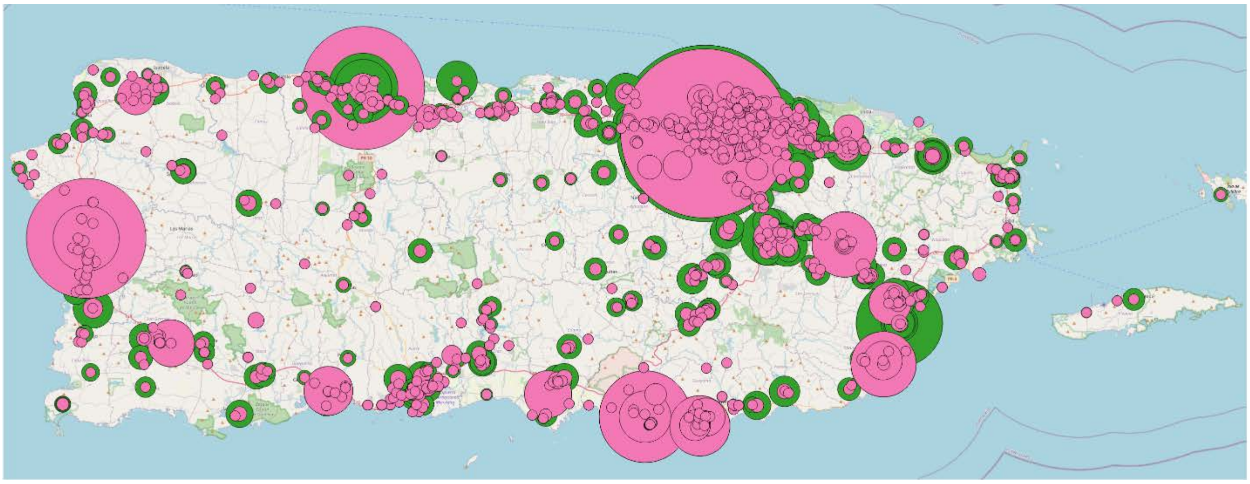

Figure 234. Layers show generation locations of wind/solar/hydropower and batteries in 2040 where size is related to (but not proportional to) the available capacity allowed for the two different scenarios.

3LS generation is green, and 1LM generation is pink. Pink 1LM layer placed on top of green 3LS layer.

Figure 235. Layers show generation locations of wind/solar/hydropower and batteries in 2040 where size is related to (but not proportional to) the available capacity allowed for the two different scenarios.

3LS generation is green, and 1LM generation is pink. Pink 1LM layer placed below green 3LS layer.

A summarized list of key observations is given as follows:

- Table 37 indicates that the amount of labor (in work crew days) expended on feeders is considerably larger than the amount of labor (in work crew days) expended on transmission and subtransmission to recover 90% of the system load in both cases.
- Observations in Figure 230 and Figure 231 show four locations that appear to have different recoveries in terms of the last 10 % of load served for the 1LS and 3LM scenarios. Furthermore, these which also appear to be related to differences tend to correlate well with the difference in the generation build-out illustrated in Figure 232 and Figure 233 buildouts between 1LS and 3LM.

- **Area 1:** More generation in the 3LS than the 1LM case here appears to correspond to a better recovery performance for 3LS.
- **Area 2:** More generation in the 1LM than the 3LS case here appears to correspond to a better recovery performance for 1LM.
- **Area 3:** In Area 3, more generation appears to be available in case 3LS. However, it is hard to extract the relative performance for 3LS to 1LM, as each case has municipalities in this area with better/worse performance.
- **Area 4:** More generation in the 3LS than the 1LM case here appears to correspond to a better recovery performance for 3LS.

10.9.3 Considerations

Considerations from system recovery analysis after severe damage from hurricanes include that Puerto Rico:

- Limit the capacity of single generation and BESS utility-scale plants and single units, given the relative size of the system, to benefit reliability and resilience in the future. Establishing standards for maximum size of plants and units could be considered. Having future utility-scale generation and BESS spread in various locations can help with grid recovery (provided those resources can help with grid recovery—see also below considerations).
- Bring new T&D and generation (including both utility-scale and DER) infrastructure for all hazards, including hurricanes, up to new standards adopted in Puerto Rico after Hurricane Maria. Because the entirety of the infrastructure cannot be hardened immediately, it is important that Puerto Rico continues developing, updating, and implementing plans for managing legacy infrastructure over time.
- Change the current paradigm to enable renewables (DERs and utility-scale) and storage to participate in grid recovery; GFM controls and black-start capability are required. Black-start capability from BESS at various locations would be very valuable for recovery processes. Pilot projects for BESS participation in black-start could be developed in the short term. Developing pilot projects for solar and wind generation participation in black-starts and system recovery, in tandem with BESS, could be beneficial to reduce dependency on fossil fuel generation in system recovery. Researching and developing participation of DERs in system recovery from the distribution system could be beneficial for more efficient system recovery after large events utilizing all available resources.
- Deploy utility-scale battery energy storage in the near term to support bulk power system resilience to extreme weather events, as well as day-to-day reliability, if properly sized, sited, and fitted with GFM controls and black-start capability.

11 Distribution Grid Impacts

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Section Summary

This section examines how increasing amounts of rooftop solar photovoltaic (PV) adoption on the distribution system may increase violations related to voltage and capacity limits as well as substation backfeeding. The section also explores violation mitigation approaches including PV inverter controls and controlled storage on the distribution system. We present an introduction to the problem and full section summary (Section 11.1) and then describe Puerto Rico's distribution system, utility demand data, irradiance data, and Distributed Generation Market Demand Model (dGen) PV adoption values that were used for quasi-static time series (QSTS) hosting capacity simulations (Section 11.2). We also describe the overall simulation approach, system violations of interest, and control schemes for PV inverters and storage devices as well as define each simulation performed (Section 11.4). Full results from each simulation are presented (Section 11.5) along with a result summary (Section 11.5.6) and a further result interpretation (Section 11.6). We show work describing a resilience benefit from additional storage on the distribution system (Section 11.7) and then present final conclusions (Section 11.8). A selection of key findings from this work is below, followed by actions stakeholders could take to advance progress toward Puerto Rico's energy goals. We identified these actions based on the results of our analysis, observations about Puerto Rico's current energy system, and knowledge of industry best practices.

Key Findings

- Some feeders as they exist in Puerto Rico today operate outside American National Standards Institute (ANSI) range A standard voltages (Kersting 2018) of 0.95 to 1.05 per unit (pu), even when there is no PV power production (e.g., at night).
  - Feeder-head voltages are typically set at 1.05 pu, and sometimes higher, leaving very little room for voltage rise introduced by distributed PV systems.
  - Nearly all capacitor banks are actively grid-connected without switching capability. This can raise voltages above 1.05 pu, even without any PV production (e.g., at night), especially during low-load periods.
- Due to the existing modeled system state, simulated feeders had to be modified to be run without experiencing violations before additional PV was included. (Section 11.4.3)
- Using these modified feeder models, distributed PV penetrations under PR100 Scenarios 1, 2, and 3 were found to exceed many distribution feeders' capacities. (Section 11.5.1)
  - Reverse power flow (more generation on a feeder than load on that feeder), or backfeeding, was found in 65%–95% of modified simulated feeders in 2050 and may begin as soon as 2024.
  - PV-caused voltage violations were also seen in 15%–55% of feeders by 2050.
- Adding utility-controlled storage and implementing PV inverter controls can reduce or entirely mitigate most reverse power flow and PV-caused voltage violations. (Section 11.5.2)
  - The amount of storage needed depends on specific storage control schemes and whether the customer-owned storage can be grid-interactive.
- Strategic charging and discharging of customer-owned batteries can reduce the grid impact of customer-owned PV systems. (Section 11.5.3 and Section 11.5.4)
- Storage typically operated to prevent reverse power flow could be used during a resilience event, such as a grid blackout, to power sections of feeders as microgrids. (Section 11.7)

Considerations

- Update system configuration and operations to maintain and ensure ANSI standard voltage ranges.
    - Replace capacitor banks with controllable units.
    - Reduce feeder-head voltage from 1.05 pu or add variable control such as time-based settings.
    - Install grid monitoring equipment to allow more visibility into system operation.
- Implement interconnection requirements and procedures for distributed generation that use advanced inverter functions such as Volt/VAR.
- Ensure distributed PV does not overload upstream service transformers.
- Incentivize temporal utilization of customer-owned batteries.
- Utility-controlled storage can be deployed progressively, obtaining benefits now while setting up the system to be prepared for higher PV penetrations in the future.

11.1 Distribution Grid Impacts Summary

This work explores the simulated impacts related to increasing amounts of distributed PV connected at the distribution level, including possible mitigation efforts to reduce or eliminate negative impacts.

In PR100 analysis of distributed solar and storage adoption projections (Section 9, page 241), yearly amounts of PV adoption were calculated for three scenarios ranging from lower to higher amounts of distributed PV (see Section 6, page 173) for a discussion of the three scenarios modeled in PR100). We used quasi-static time series (QSTS) simulations to simulate the worst-case scenario (minimum demand and maximum irradiance day) such that safe system operation could be ensured for all conditions.

We converted 20 utility-provided distribution feeder models to OpenDSS from Synergi and then further modified them such that the models reported no voltage, thermal (overloading), or backfeeding violations in a base case scenario with no distributed PV. These modifications involved reducing the substation voltage and removing all capacitor banks.

After these modifications, in our simulation of PV adoption in Scenarios 1, 2, and 3, we found backfeeding to be the most common violation among all modeled feeders when no mitigation controls were deployed. While PV inverter controls such as Volt/VAR and Volt/Watt were able to reduce some voltage violations, they increased line loading due to increased reactive power flow. Controlled storage was required to eliminate backfeeding violations.

We executed three storage simulations on distribution feeders, classified as (1) utility, (2) distributed, and (3) combination, that used different placement and sizing options of distribution system-connected storage. We found that using utility-controlled 3-hr storage equal to two times total feeder PV adoption eliminated all substation backfeeding in the modeled systems. Combining distributed and utility-controlled storage was found to have the most benefit in relation to violation reduction and estimated cost savings. Large collections of storage reduced line loading by allowing excess generation to be stored closer to the distributed generation source instead of being sent all the way back to the substation. Additionally, grid-connected storage could have a resilience benefit during times when energy cannot be sourced from the bulk system.

Regardless of scenario, we found service transformers to be overloaded almost immediately. This was due to placing the simulated PV systems without consideration for service transformer capacity. For example, if a service transformer had five customers, it may have been allocated 20 kW of PV systems, regardless of whether the service transformer had a 25 kVA or 10 kVA capacity. However, such situations are expected to be common in Puerto Rico today and into the future, as it is not expected that customers will consider, or are required to consider, the size of their service transformer when making PV adoption decisions.

Simulations show voltage violations and service transformer overloading as early as 2022 and backfeeding in 2024. These violations may in fact be occurring on the system right now, but due to lack of visibility into distribution system operation, there is no way to verify these findings.

11.2 Introduction

Across the United States, approximately 30% of solar photovoltaic (PV) generation is connected to distribution systems. The remainder comes from utility-scale installations connected to the transmission system.[149] In Puerto Rico in October 2023, over 80% of installed PV capacity—a total of 680 MW—was connected to the distribution system and the number of installations was increasing rapidly (3× increase since 2021) (LUMA 2023d), highlighting the importance of understanding how these systems will influence distribution grid operations.

Distribution systems are typically designed for radial power flow: power is generated at a powerplant, flows through transmission lines to a substation, and then follows a unidirectional path from substation to loads connected on a distribution feeder. High penetrations of renewables installed on the distribution system will fundamentally change this paradigm by generating power at various locations across the distribution feeder, resulting in varied power flow directions and magnitudes, and more variable voltage profiles due to voltage increases caused by the renewables injecting power to the grid.

These changes to distribution system operations will create both concerns and opportunities. Examples of potential concerns include damage to distribution system equipment or unsafe operating conditions on feeders due to excessive power injection by renewables. There can also be concerns about how distributed renewables will interface with the larger electric system. Existing inverter-based resources installed in Puerto Rico are "grid-following" devices, meaning they will turn off if voltages or grid frequency falls outside expected levels. This can lead to a cascading failure if one or more generators are lost, as the renewables will turn off rather than ramp up to provide grid support.

Opportunities for distributed renewable systems include the ability to control them to provide grid support. Advanced inverter functions such as Volt/VAR and Volt/Watt can be used to stabilize voltage on distribution feeders. The distributed nature of renewables can be an asset itself: distributed renewables can form microgrids that continue to deliver power to critical services even when main grid operations are compromised (e.g., due to a failed transmission line). However, to take advantage of these opportunities, new control schemes, operational strategies, and equipment will need to be deployed. This section describes the analysis performed as part of PR100 Task 9: Distribution System Analysis[150] to investigate these challenges and opportunities.

11.3 Modeling Inputs

11.3.1 Distribution System Models

Distribution system models representing real feeders in Puerto Rico were obtained from Puerto Rico transmission and distribution system operator LUMA. Additional information provided by LUMA included feeder demand timeseries, feeder characteristics such as number and types of customers, and related geospatial data.

[149] "Electric Power Monthly: Table 1.1.A. Net Generation from Renewable Sources: Total (All Sectors), 2013-August 2023," EIA, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_1_01_a.

[150] All PR100 tasks are listed in Figure 2, page 7.

11.3.1.1 Model Conversion

OpenDSS distribution feeder models were constructed by converting Synergi models provided by LUMA. The voltages of the converted models were compared to measured voltages at several locations to verify that the models were within the range of the physical system. Most feeder models received modeled only the primary distribution circuit and did not include the service transformers. To support a more complete analysis, service transformer models were added based on information available from LUMA's GIS database. The secondary circuit was not modeled; loads were connected directly to the low-voltage side of the service transformers.

11.3.1.2 System-Wide Feeder Classification

All distribution feeders were classified according to voltage level and energy use by customer type. Table 38 lists the three voltage classes which were defined based on maximum feeder kV. It is worth noting that these are not the only operating voltages present in the current the system, but merely threshold voltages to divide feeders into specific classes. These class definitions are unique to the Puerto Rico distribution system.

Table 38. Distribution Feeder Voltage Classes

Feeder Voltage Class	Highest Feeder Voltage [kV] Line-to-Neutral / Line-To-Line
Low	2.77 / 4.80
Medium	4.80 / 8.32
High	7.62 / 13.2

Distribution feeders were classified according to the voltage classes in Table 38. As shown in Figure 236, most distribution feeders in the current system are low-voltage (629), followed by high-voltage (457) and medium-voltage (205).

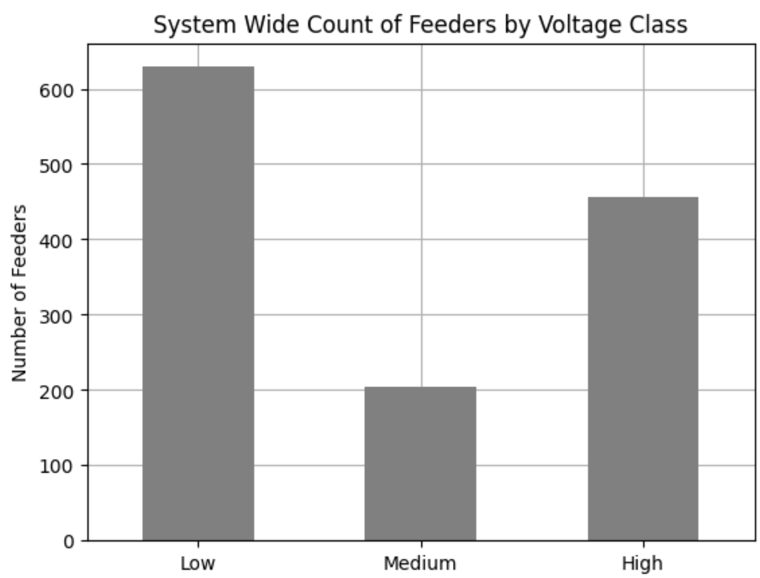

Figure 236. Voltage classes of entire Puerto Rico distribution system. Refer to Table 38 for voltage class definitions.

Average annual energy consumption by customer type and average annual customers by type were used to calculate the energy class for each feeder. The average energy usage for each type of customer (residential, commercial, industrial, other) was calculated by analyzing system demand data from 2013 to 2020. As shown in Figure 237, the average percentage of energy used by commercial customers was approximately 48% while residential customers used roughly 37%. Industrial customers used nearly 13% of total annual energy and the remaining 2% was consumed by the "other" type of customers.

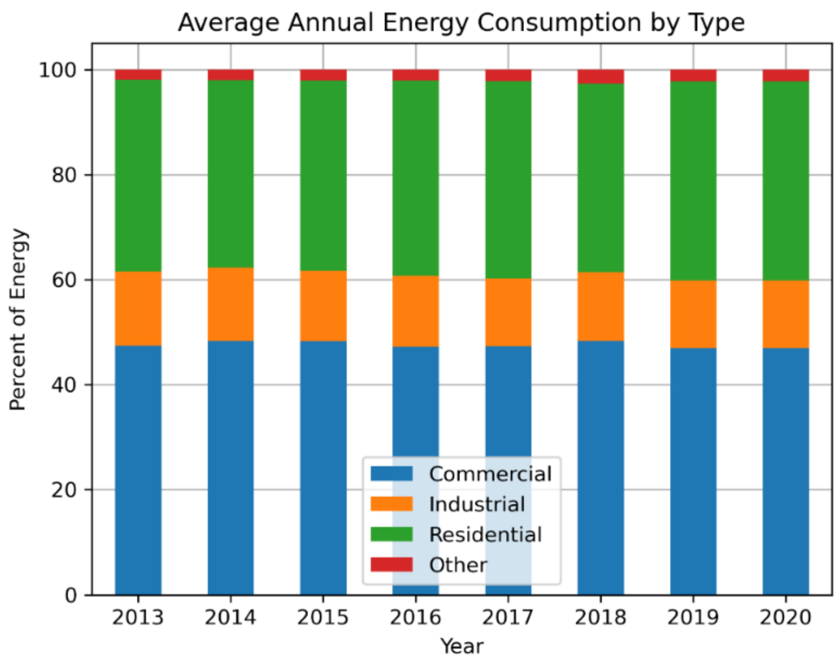

Figure 237. Average annual energy consumption by customer type

As shown in Figure 238, as a percentage of total customers, the residential type is dominant with an average of 91% of annual customers. Commercial customers account for roughly 8% of each year, with industrial and other types of customers being less than 1% of the total customer base. No significant changes over time in the allocation of customers by type were observed for the 8 years available (2013 to 2020).

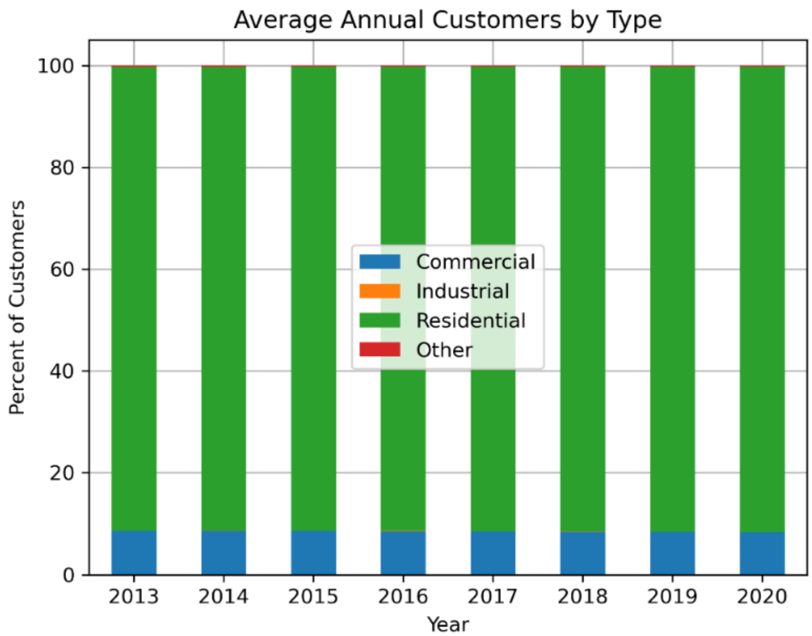

Figure 238. Average annual customers by type

To account for the large difference between the number of customers and energy use, a scaling factor for each nonresidential type of customer was calculated. Residential energy use was assumed as the baseline, and each additional type of energy use was normalized to residential energy use. The resulting scaling factors are shown in Table 39. These weighting factors can be used to classify the dominant customers on feeders based on energy consumption rather than just customer counts. For example, one average industrial customer would use 762× the amount of energy as one average residential customer may use annually, and a feeder with one industrial customer and 100 residential customers might be considered an "industrial" feeder because industrial load is more than seven times larger than residential load, even though the number of residential customers is much higher.

Table 39. Average Customer Energy Scaling Factors

Customer Type	Scaling Factor
Residential	1
Commercial	14
Other	23
Industrial	762

To perform this feeder classification, the associated customer type count for each distribution feeder was multiplied by the related scaling factor listed in Table 39. The resulting average annual energy consumption by feeder was classified according to the majority customer type. If there was no customer type that used over 50% of the calculated annual energy, the feeder was classified as "Mixed" followed by the largest energy customer type. The system-wide energy use classifications are shown in Figure 239. This division matches the energy consumption shown in

Figure 237 with commercial type feeders being the most common, followed by residential and then finally industrial. It is worth mentioning that there were no "Other" type feeders identified.

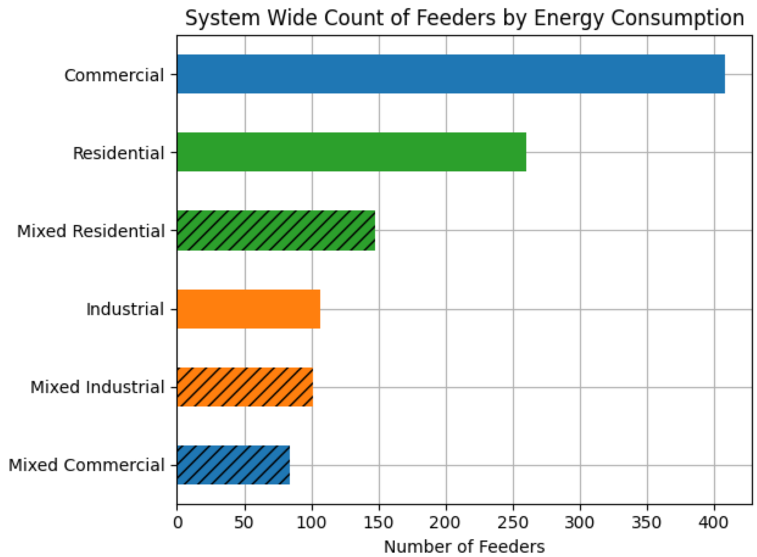

Figure 239. Count of system feeders based on energy consumption.

The result of combining voltage and customer classifications for feeders that had the required input data is shown in Table 40. The most common type of feeder is low-voltage commercial followed by high-voltage commercial. Residential feeders for low and high voltage are the third- and fourth-most common feeders respectively.

Table 40. System-Wide Feeder Counts Organized by Voltage and Customer Classes

Customer Class	Low Voltage	Medium Voltage	High Voltage
Commercial	233	47	128
Residential	120	38	102
Industrial	68	15	24
Mixed Residential	47	42	59
Mixed Commercial	26	20	38
Mixed Industrial	45	28	28

11.3.2 Time Series Data

11.3.2.1 Demand Profiles

Hourly feeder level demand data from 2019 was provided by LUMA and used for the demand profiles in this work. First, the minimum and maximum demand day profile was selected for all feeders that had demand data. These profiles were then classified according to the feeder classifications from the previous section. Because the demand data is known to be incomplete and contain data errors, a filtering process was used to select profiles that were deemed as valid.

Daily profiles were deemed valid if:

1. No missing data points from the selected day were found.
2. Total day demand was above 3 MWh.
3. Demand did not go above a maximum level based on kV rating of feeder, as listed in Table 41.
4. Average day demand was above a minimum level based on kV rating of feeder, as listed in Table 41.
5. Largest percentage difference from the profile mean was at least +/-15%, but no larger than +/-50%.
6. Percentage change between hourly steps was less than +/- 50% for all steps.

The median profile of the remaining valid profiles was identified for each feeder class and used in cases where demand data were missing for a feeder of the same type.

Table 41. Demand Profile Validity Rules by Voltage Level. Refer to Table 38 for voltage class definitions.

Validity Rule	Low Voltage	Medium Voltage	High Voltage
Maximum Demand [MW]	2.5	5.0	10.0
Minimum Average [MW]	0.25	0.50	1.00

11.3.2.2 Irradiance Profiles

Solar irradiance profiles were obtained from data as described in Section 7 (page 186). These hourly time series profiles were associated to each municipality of Puerto Rico. Because distribution feeders can span multiple municipalities, a centroid was created for each feeder and that point defined what municipality should be associated to that feeder. The maximum and minimum irradiance day profiles were collected by summing the values for each day and then selecting the profile associated with the largest and smallest summation.

11.3.3 PV Adoption Data

The utilized outputs of dGen in this work were municipality level agent estimations of PV adoption every 2 years from 2020 to 2050. To use this information at the distribution feeder level appropriately, a deaggregation was performed so that individual feeder level amounts of PV and storage adoption could be defined. Additionally, existing PV systems as of 2020 had to be identified and associated to the appropriate distribution feeder. LUMA provided geospatial data of primary distribution feeder conductors, electrical accounts, and existing distributed generation was used to inform the deaggregation process.

The first step was to filter, correct, or more generally, clean the database of electric conductor information such that only features with circuit names consisting of four integers followed by a dash and two more integers were considered valid (e.g., 1234-56). Each electrical account and distributed generation point was then associated with the nearest feature of the cleaned primary conductor data. This resulted in all electrical accounts and distributed generation being associated to a distribution feeder. Via this process, and a related database of existing distributed generation installations, the existing distributed generation for each feeder was known.

One issue of note during this step was that feeder lines may be placed "on top" of one another in the geospatial data which could have led to elements being associated with incorrect feeders. However, the error introduced by this process was deemed acceptable for lack of more detailed data. Electrical account data were associated with the Census defined municipality in which it spatially existed. This process was not subject to potential geospatial errors mentioned above because municipality polygons are well-defined and non-overlapping, making it trivial to determine which municipality a point (electrical account) exists in.

Unlike electrical account and distributed generation point type data, distribution feeders consist of lines that can span multiple municipalities. To handle the situation where a single feeder may have electrical accounts in multiple municipalities, all electrical accounts for each feeder were grouped by the municipality and summed. This total municipality electrical account value was used to evenly distribute the total predicted municipality level adoptions evenly to each distribution feeder.

Once this process was executed for each municipality, all feeders had the appropriate allocation of the total PV adoption prediction based on location and number of electrical accounts served in each municipality. An example of this deaggregation is shown in Figure 240 where the normalized adoption for a municipality is allocated to municipality feeders.

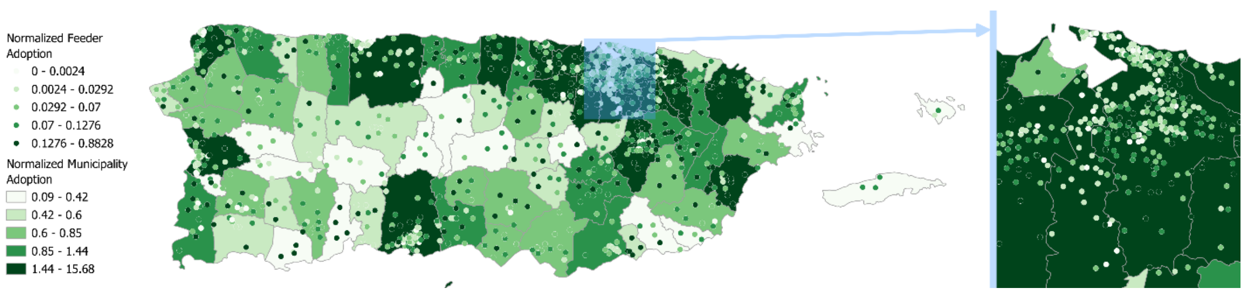

Figure 240. 2050 3LS normalized adoption by municipality and feeder.

11.3.4 Feeder Level Technology Adoption Allocation

To distribute the total feeder level PV adoption described in the previous section across a distribution feeder, various allocation rules were used. From the dGen outputs, agent classifications defined customer type as residential or nonresidential. For residential PV systems, each system size was either 2.5, 3.0, 4.0, or 6.0 kW based on median income.

Based on the dGen outputs, systems were modeled on distribution feeders at load locations that were not 3-phase and had a base voltage above 0.2 kV but below 1.0 kV. If existing PV was identified on a modeled feeder, the same allocation rules as residential systems were applied, but all were sized at 5 kW due to available information. All nonresidential systems were also sized at 5 kW for the same reason but were placed on the secondary of transformers that were rated between 25 kVA and 250 kVA. Because many nonresidential PV systems may end up being placed at the same node (due to the typically small number of 25–250 kVA transformers), effective PV system sizes at a single location could be much larger than 5 kW. In all instances, the voltage and phase connection of additional PV systems matched that of the load(s) at the selected location.

Every residential PV system was assumed to also adopt a storage system. Each storage system was sized as 5 kW with 15 kWh energy capacity and placed at the same node as the PV system. Again, because multiple PV systems can be connected to the same node, effective storages sizes can be larger than 5 kW.

Storage systems described as “utility-controlled” or “utility” are stand-alone storage systems (without an associated PV system) controlled by the utility. These are included in the modeling to show how they could help alleviate hosting capacity concerns including backflow and voltage violations. Utility storage was sized as 250 kW with 750 kWh of energy capacity, though more than one storage system could be located at the same node (e.g., 500 kW, 750 kW, and 1,000 kW total at one location are all possible).

Because optimizing the location of utility storage was beyond the scope of this analysis, we used a spatial allocation to site the utility storage. Four distribution system primary connected locations on each feeder were chosen for utility storage based on the total number of downstream customers. The first location was close to the substation: less than one-third of customers were closer to the substation than the first utility storage location. Two additional storage locations were chosen such that each was roughly halfway along the feeder—defined as having between one-third and two-thirds of customers closer to the substation than the chosen location. The final location was far from the substation, such that less than one-third of customers were further from the substation. Utility-controlled storage placement assumed an appropriately sized transformer would be installed at each location. An example of storage placement on a distribution feeder is shown in Figure 241.

Total utility storage deployment depended on simulation case but was either 2× (utility only simulation in Section 11.4.7.2) or 1× (combined simulation in Section 11.4.7.4) total PV adoption. For example, a feeder with a total of 1 MW of distributed PV would have either 2 MW/6 MWh (utility only) or 1 MW/3 MWh (combined) of total utility storage. All storage devices were assumed to start each simulation at 20% initial state of charge (SOC) and generate or absorb real power only. The 20% initial SOC was chosen as an optimal initial SOC as it is typically recommended that storage be operated between 20% and 80% SOC.

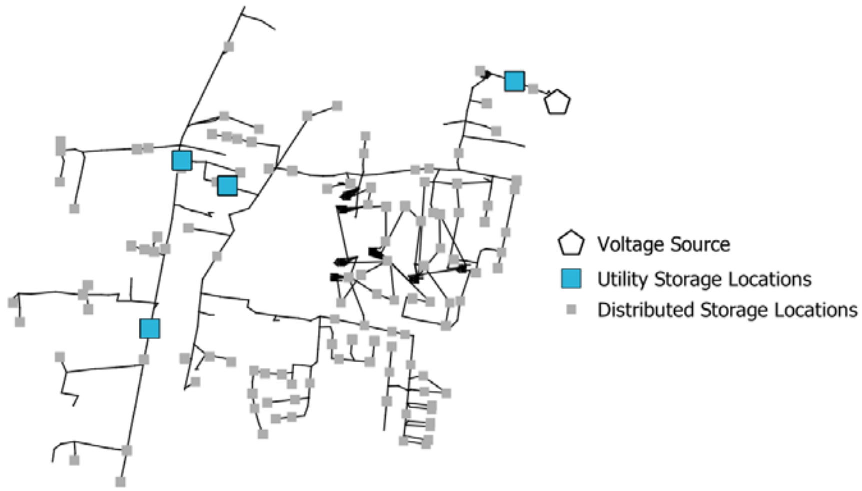

Figure 241. Example of utility and distributed storage placement on a distribution feeder

11.4 Simulation Descriptions

11.4.1 Year-by-Year Integration Analysis

This work used a distinct simulation for each study year 2020, 2022, 2024…2050 with quasi-static time series simulations covering a 24-hr period. The simulation results shown use the minimum day electric demand profile and the maximum irradiance profile to represent a worst-case scenario. It is typical in utility planning to analyze the worst-case scenarios to ensure safe and effective operation of the system in all conditions. For each study year, the worst-case day is simulated using a 1-hr time-step due to the resolution of input time series data. Instead of stopping when a violation occurs, as might happen in a more traditional hosting capacity analysis, all years of adoption are simulated to allow the full impact of adoption to be analyzed. Thus, some of the simulations represent extreme situations such as very high voltages or massive amounts of reverse power flow (backfeeding), which would be considered unsafe and not be allowed in real life.

11.4.2 Violation Definitions

Violations considered for the integration simulations included voltage violations, thermal violations, and substation backfeeding violations. Any voltage outside the 0.95 pu to 1.05 pu ANSI range was considered a voltage violation. This includes both primary and secondary voltage locations. Thermal violations, or overload violations, were reported anytime a line or transformer was operating above its nameplate rating. For lines, this value was typically given in amps while transformers were rated in kVA. Because the existing power system was not designed with substation backfeeding in mind, any time the power delivered from the modeled voltage source was calculated to flow in reverse (i.e., generation on the feeder exceeded load on the feeder), a backfeeding violation was registered. For clarification, only one feeder per substation was modeled at any time. So, while a modeled feeder may be backfeeding to the substation, the substation may or may not be backfeeding to the transmission system.

11.4.3 Modeled Feeder Changes

The converted OpenDSS feeders required modification to allow a clearer look at system impacts caused by additional distributed PV. Originally, many modeled voltage sources were set at 1.05 Pu. While this may reflect actual grid operation, it leaves essentially no space for voltage rise before ANSI violations occur. To resolve this, all modeled feeders had their voltage source set to 1.03 pu, which to our knowledge is within the range of values used in other locations.

Additionally, many feeders had capacitor banks that were always on (i.e., no mechanism for switching on and off). This is contrary to most distribution-connected capacitors in other locations, which are typically switched on and off based on factors including voltage, season, or operator control signals. These always on capacitors may have been used historically to increase voltage, targeting heavy demand times, but our initial simulations showed they would often act to increase an already high voltage, especially during low-load periods. To facilitate acceptable voltages these assets were simply disconnected in our simulations and then a maximum day demand simulation was performed to ensure no low-voltage violations were observed.

While these simulated changes allowed a base case simulation with no additional PV to be executed without any violations, it is believed the mentioned issues are causing real voltage violations on the current system. We cannot completely verify this claim due to lack of visibility into the current system operation; however, unmodified simulated voltage levels were matched to available system voltages in cases where data were available.

11.4.4 Modeled Feeder Selection

Twenty OpenDSS distribution feeders were selected from the Synergi converted models for year-by-year grid integration simulations. The selected feeders had reasonable load allocation and voltage profiles. While some feeders had initial violations, they were all resolved by applying the changes mentioned in the previous section. Figure 242 shows the municipalities that the modeled distribution feeders serve while Figure 243 shows the voltage classes of the modeled feeders. Unlike the system-wide feeder voltage classifications shown in Figure 236, most modeled feeders were high-voltage. However, all voltage classes were represented in the modeled feeders. It is worth mentioning again that the defined voltage classes for this work are not standard voltage classes among distribution systems, but merely used to differentiate between the available models in this work. Feeders with voltages equal to or below 2.77 / 4.80 kV were classified as “Low,” while feeders with voltages equal to or greater than 7.62 / 13.2 kV were classified as “High,” and any feeder in between those bounds was classified as “Medium.”

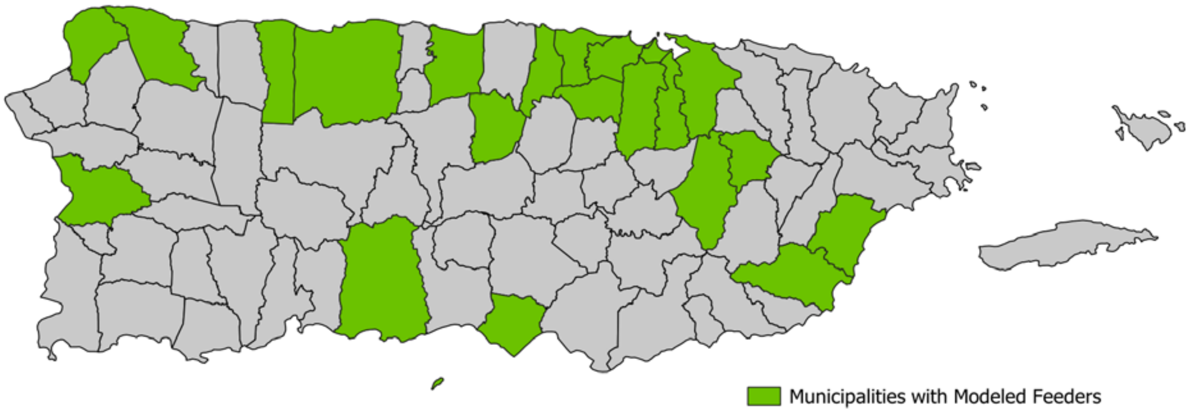

Figure 242. Municipalities with modeled distribution feeders

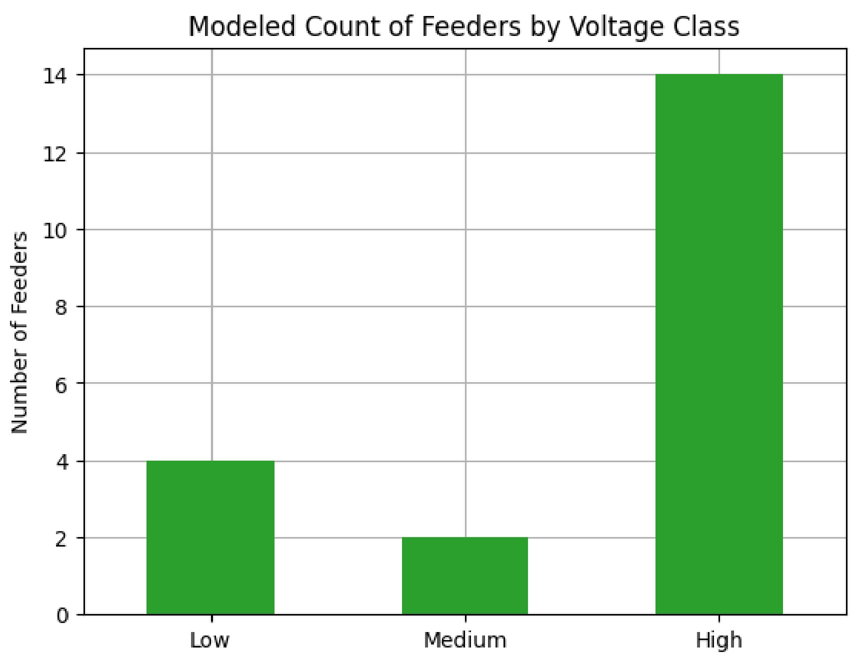

Figure 243. Voltage class of modeled feeders. Refer to Table 38 for voltage class definitions.

Figure 244 shows that the energy consumption classes of the modeled feeders is mostly commercial, followed by residential, and one industrial. This distribution is similar to the system-wide feeder characteristics shown previously in Figure 239.

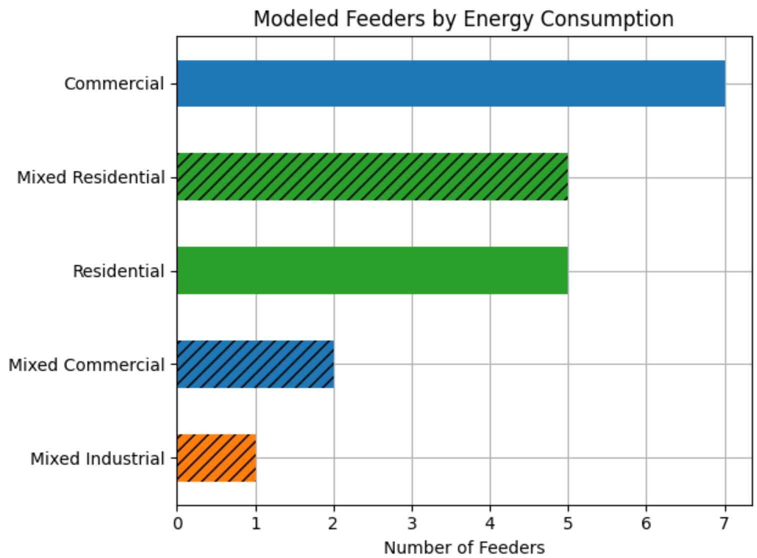

Figure 244. Energy consumption classes of modeled distribution feeders

Table 42 presents the voltage and energy usage classes for the modeled feeders. Each customer class of feeder has a modeled high-voltage feeder. Medium-voltage feeders are sparser: there are no medium-voltage commercial, residential, or mixed industrial feeders in the selected models. Additionally, there were no low-voltage feeders in the modeled feeder set for any mixed customer classes.

Table 42. Modeled Feeder Counts of Voltage and Customer Classes. Refer to Table 38 for voltage class definitions.

	Low Voltage	Medium Voltage	High Voltage
Commercial	2	—	5
Residential	2	—	3
Mixed Residential	—	1	4
Mixed Commercial	—	1	1
Mixed Industrial	—	—	1

11.4.5 Inverter and Storage Control Schemes

In most simulations, Volt/VAR and Volt/Watt controls were applied to PV inverters. The control curves were either the recommended IEEE 1547 curve or a aggressive curve. Figure 245 shows the two curves used for Volt/VAR control. The main differences between the aggressive and recommended curves are the pu voltage point at which maximum VAR support is given (+/- 0.05 pu versus +/- 0.08 pu), and the maximum amount of VAR support (± 0.5 pu versus ± 0.44 pu). In either situation, the inverters are intended to provide VAR support to help local voltages remain out of violation ranges.

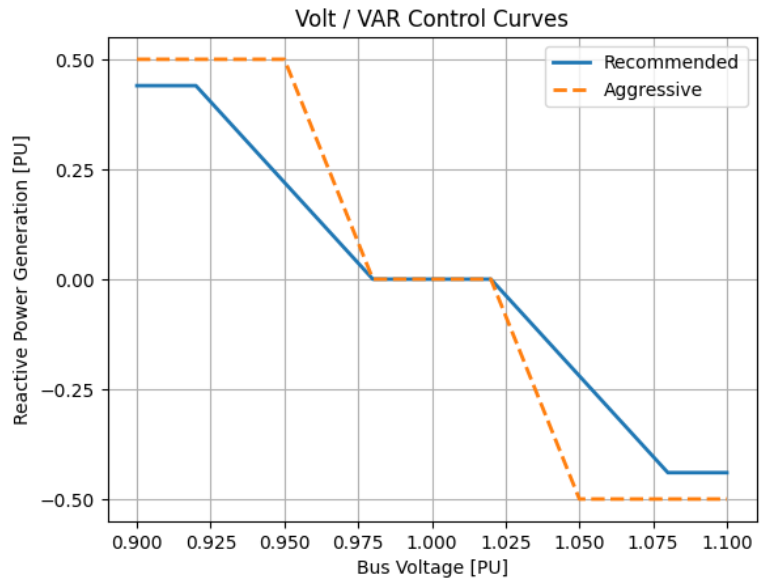

Figure 245. Control curves for recommended and aggressive Volt/VAR control

The two control curves used for Volt/Watt control are shown in Figure 246. The aggressive control effectively stops all real power from being generated if local voltage is beyond 1.05 pu, while the recommended settings allow 20% real power generation if voltage is beyond 1.1 pu.

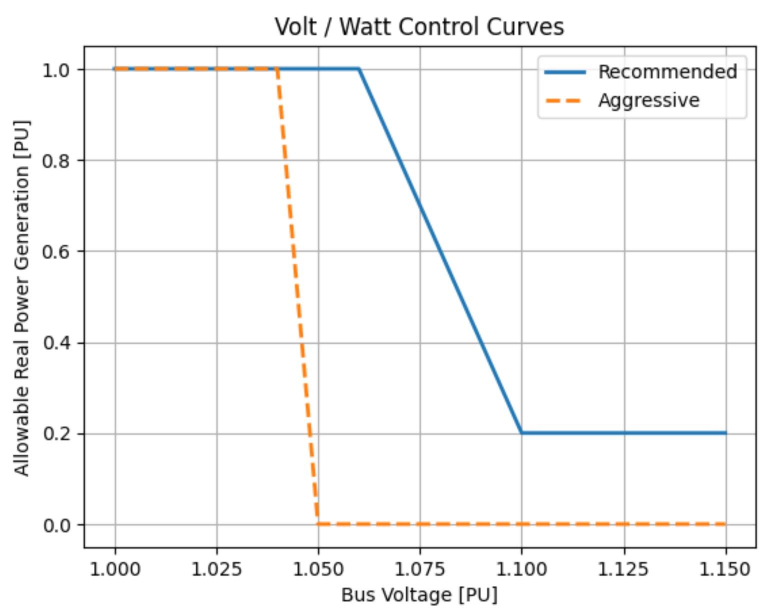

Figure 246. Control curves for recommended and aggressive Volt/Watt control

The storage fleet was controlled using a peak shave low control scheme. In this scheme, the line leading away from the voltage source was monitored and if power was found to be flowing from the feeder to the voltage source, the storage fleet is then commanded to charge the amount required to stop backfeeding. If there is not enough power or energy capacity in the storage fleet, backfeeding will still occur. Characteristic responses from uncontrolled, normally controlled, and capacity limited control cases are shown in Figure 247. In the capacity limited case, after the storage SOC reaches 100%, system behavior reverts to the uncontrolled case.

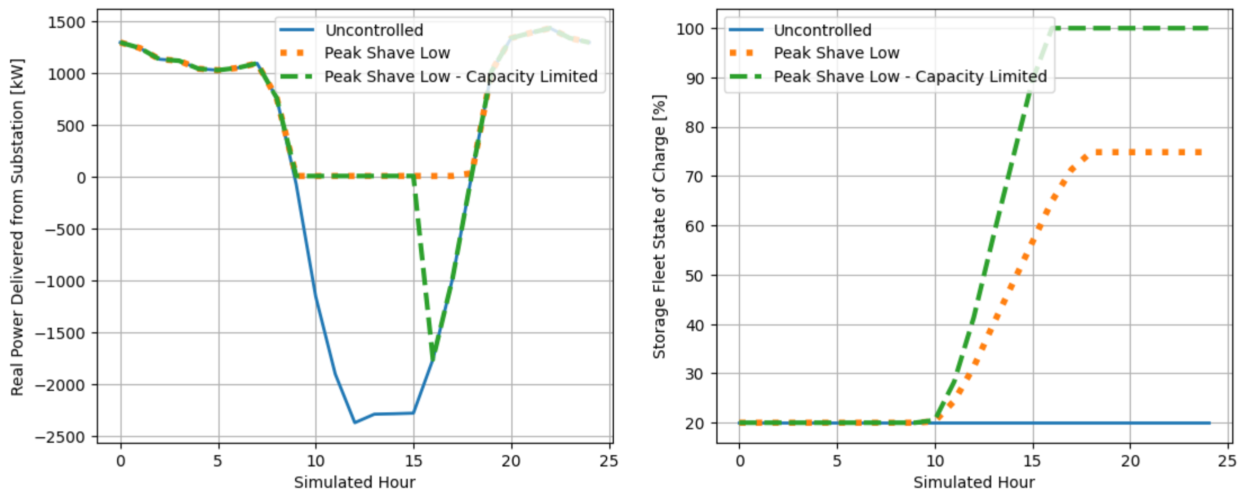

Figure 247. Substation real power and storage SOC showing peak shave low control

11.4.6 Simulation Cases

11.4.6.1 Scenario Descriptions

Of the six scenarios generated by work presented in Section 7 (page 186), only three were chosen to be simulated using the year-by-year integration analysis method. The selected scenarios were 1LM, 2LS, and 3LS. All scenarios are depicted in Figure 248 which shows that the scenarios predict anywhere between approximately 2.5 GW and 6 GW of distributed PV by 2050. This corresponds to approximately 4× to 10× the current PV penetration. Scenario 1LM represents the least amount of distributed PV while scenario 3LS has the most PV adoption. Scenario 2LS was also simulated as it represents a scenario somewhere between the two bookend cases.

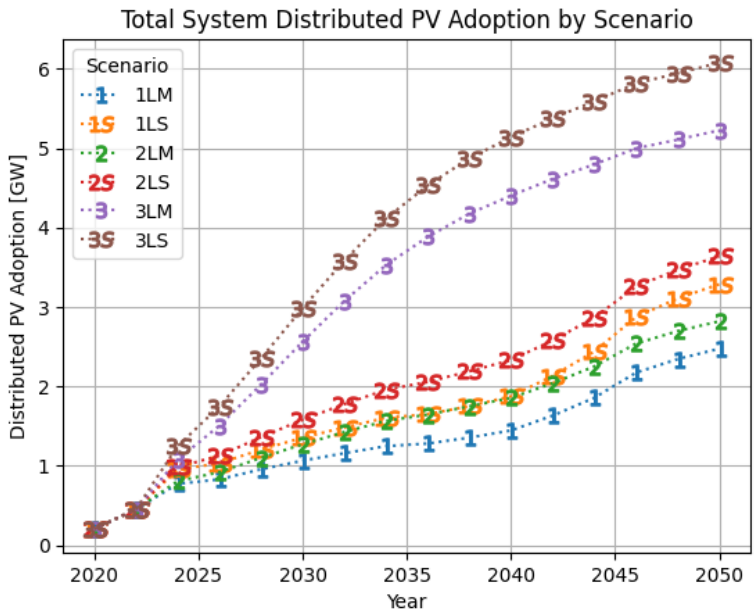

Figure 248. Total system PV adoption by scenario

Each year of dGen adoption consisted of various sizes of PV system related to customer type and income level. Figure 249 shows that the most common system size was 6.0 kW, which corresponds to residential customers with the highest income level. The next most common size was 5.0 kW, which was the assumed size for nonresidential systems and existing PV systems.

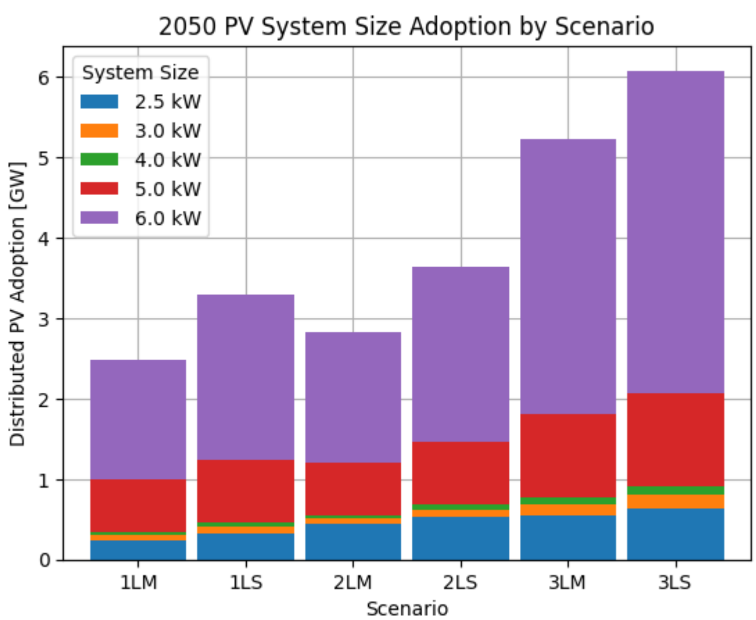

Figure 249. Total adoption by PV system size and scenario in 2050

11.4.7 Simulation Descriptions

To differentiate results from each scenario, control scheme, and distributed storage approach, four simulations were defined. In all instances, only the 20 modeled feeders previously described were used. This section describes each simulation and the differences between them.

11.4.7.1 Uncontrolled Simulation

The uncontrolled simulation included distribution feeder model changes mentioned in Section 11.4.3 but did not include PV inverter controls or use any storage. This simulation was meant to reflect a do-nothing case that allowed all predicted PV to be connected to each feeder while any storage adoption was used only for resilience during grid outages.

11.4.7.2 Utility Storage Simulation

The utility storage simulation also includes feeder model changes mentioned in 11.4.3, but enforces PV inverter control on new PV systems and storage controls on utility storage. Existing PV systems remain uncontrolled. In this case, both inverter control schemes were simulated to show the differences between the two sets of control curves. The total utility storage amount was defined to be twice the PV adoption amount of each year, rounded up to the nearest 250 kW.

11.4.7.3 Distributed Storage Simulation

The distributed storage simulation again includes feeder model changes mentioned in 11.4.3 and assumes aggressive PV inverter control on new PV systems (existing PV systems were uncontrolled). Additionally, this simulation assumes the distributed storages are controlled to help absorb excess generation that may cause backfeeding at the substation. The distributed storage was assumed to be a 5-kW system with 15 kWh of storage per PV system.

11.4.7.4 Combination Storage Simulation

The combination storage simulation is a mix of the utility and distributed storage simulations. Distributed storage systems are sized and controlled the same as the distributed storage simulation while utility storage is additionally included in the simulation. The main difference is that the utility storage is scaled only to match the PV adoption rounded to the nearest 250 kW. Both kinds of storage (utility and distributed) act together to prevent substation backfeeding and other violations. PV inverter controls were again assumed to follow the aggressive control scheme curves.

11.5 Simulation Results

11.5.1 Uncontrolled Simulations

The uncontrolled simulations in this section are meant to identify the implications of allowing all distributed PV to be grid-connected while doing nothing to mitigate any negative system impacts. Many of the presented operating conditions would not be tolerated in a physical system due to protective actions taken against substation back feeding and extreme voltages.

11.5.1.1 Scenario Violation Overviews

The most common violations across all scenarios were backfeeding, high voltages, and overcapacity transformers. Figure 250 shows that backfeeding may occur as soon as 2024 with 65%–95% of modeled feeders experiencing backfeeding by 2050, depending on scenario.

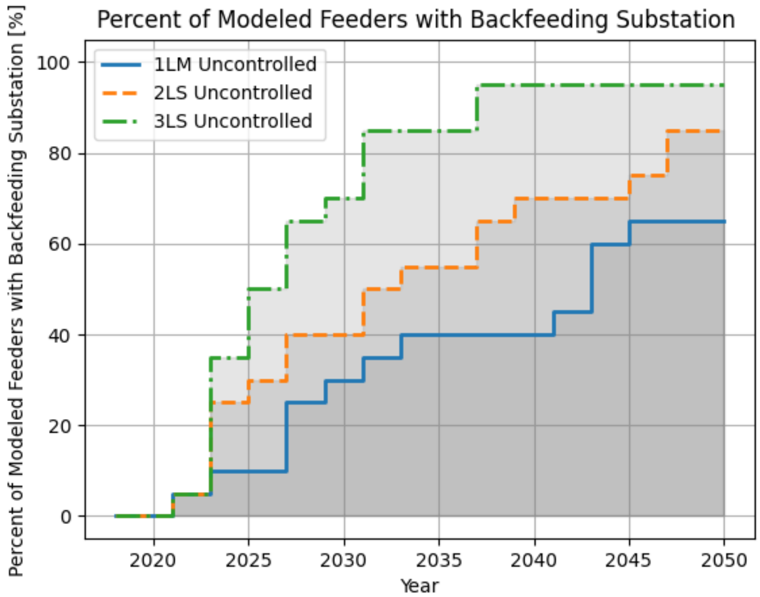

Figure 250. Percentage of modeled feeders with backfeeding violation in the uncontrolled simulation

Figure 251 shows that secondary overvoltages were more common than primary overvoltages in the uncontrolled case. By 2050, 65%-95% of modeled feeders reported an overvoltage on the secondary system while only 15%-55% of feeders had a primary voltage violation.

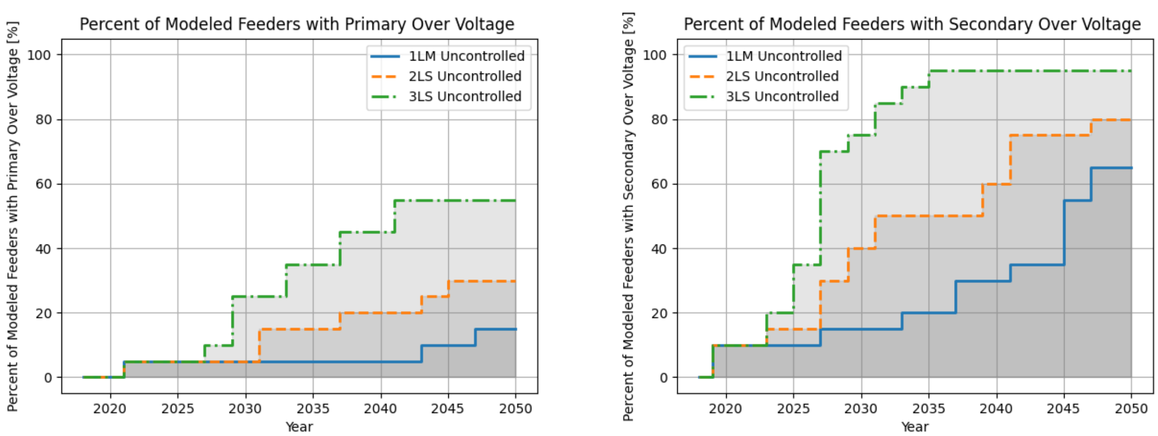

Figure 251. Percentage of modeled feeders with primary and secondary voltage violations in the uncontrolled simulation

In all scenarios, some service transformers were found to be overcapacity in the first year simulated. By 2050, 60%-90% of modeled feeders reported an overcapacity transformer. We note, though, that mitigation of overcapacity service transformers is typically more simple and routine—replacement with a larger service transformer—than mitigation for other types of violations.

Lines were found to have less overcapacity violations in general. There were no overcapacity lines in the 1LM scenario, and only 35% of modeled feeders had such a violation by 2050 in the 3LS scenario. Line and service transformer overcapacity violation overviews for all scenarios are shown in Figure 252.

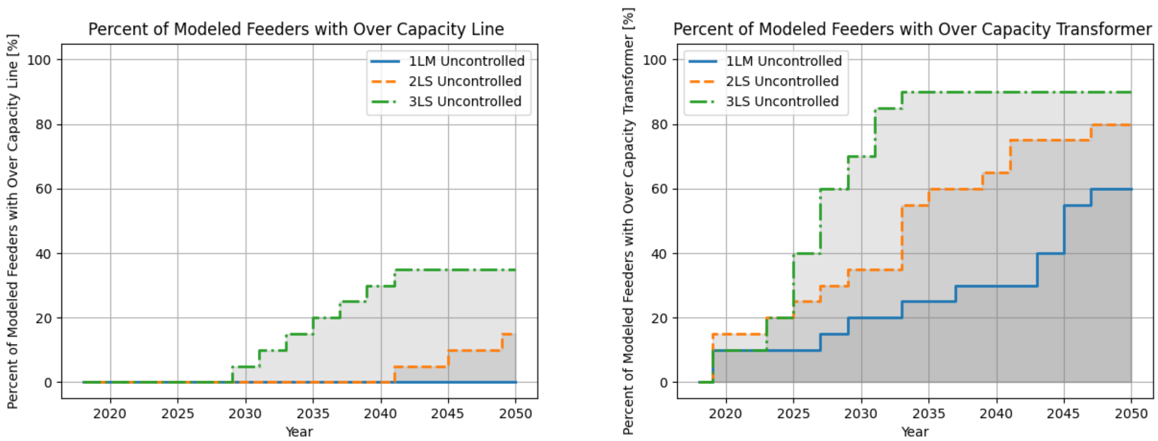

Figure 252. Percentage of modeled feeders with overloading line (left) and service transformer (right) violations in the uncontrolled simulation

11.5.1.2 Detailed Scenario Violations

Figure 253 shows the percentage of modeled feeders that registered a violation during the uncontrolled 1LM scenario. Of all violations, backfeeding is one of the most common among modeled feeders starting in 2024. Secondary voltage violations and over loaded transformers were the next most common. There were no observed overcapacity lines in this scenario.

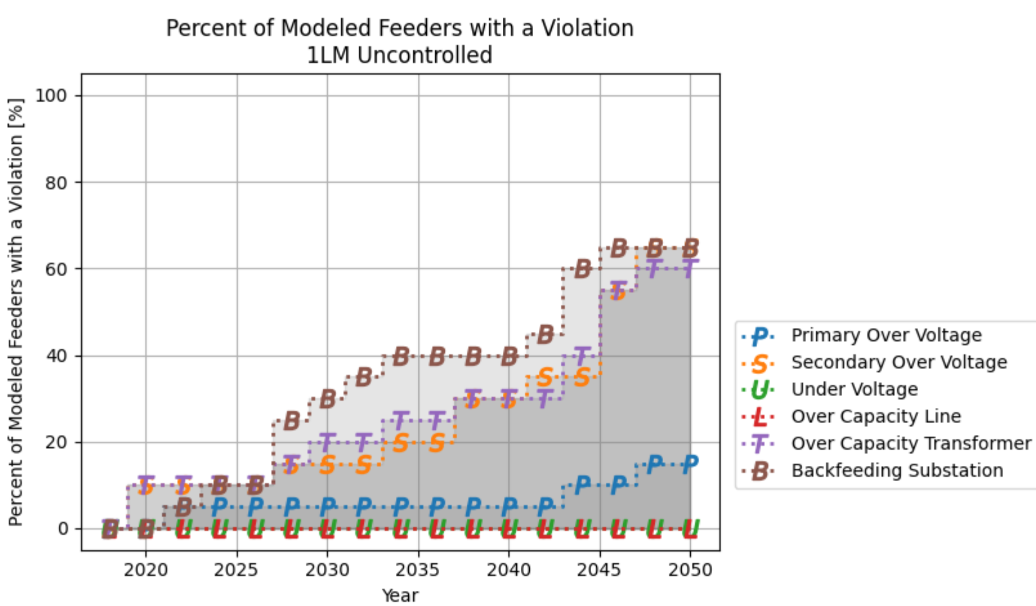

Figure 253. All violations for the uncontrolled 1LM simulation

Despite service transformer overloading being reported in 60% of modeled feeders by 2050 for scenario 1LM, Figure 254 shows that less than 10% of each modeled feeders' transformers reported an overcapacity violation. Additionally, while 65% of feeders reported a secondary overvoltage condition in the same year, this was likely associated to less than 5 % of feeder buses, though outliers may have reported up to 30% of system buses being over voltage. Because relatively few service transformers per feeder are affected, and because upgrading service transformers is typically a relatively routine utility process, we anticipate service transformer overloading to be of lesser concern than other violations.

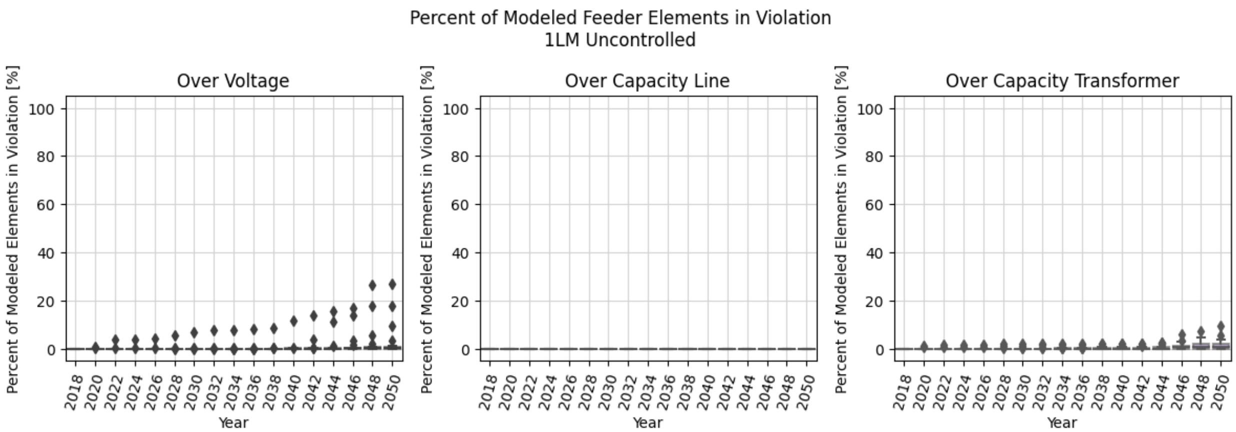

Figure 254. Percentage of feeder elements in violation for the 1LM uncontrolled simulation

Scenario results of 2LS are shown in Figure 255. These results show a similar trend as 1LM, where substation backfeeding is one of the most common violations and occurrences of secondary overvoltages and transformer over capacities are alike. Backfeeding was seen as early as 2022 with half of modeled feeders experiencing backfeeding by 2032, and 85% of feeders reporting backfeeding by 2050. Primary overvoltages were reported in 30% of modeled feeders and an overcapacity line violation was found in 15% of models.

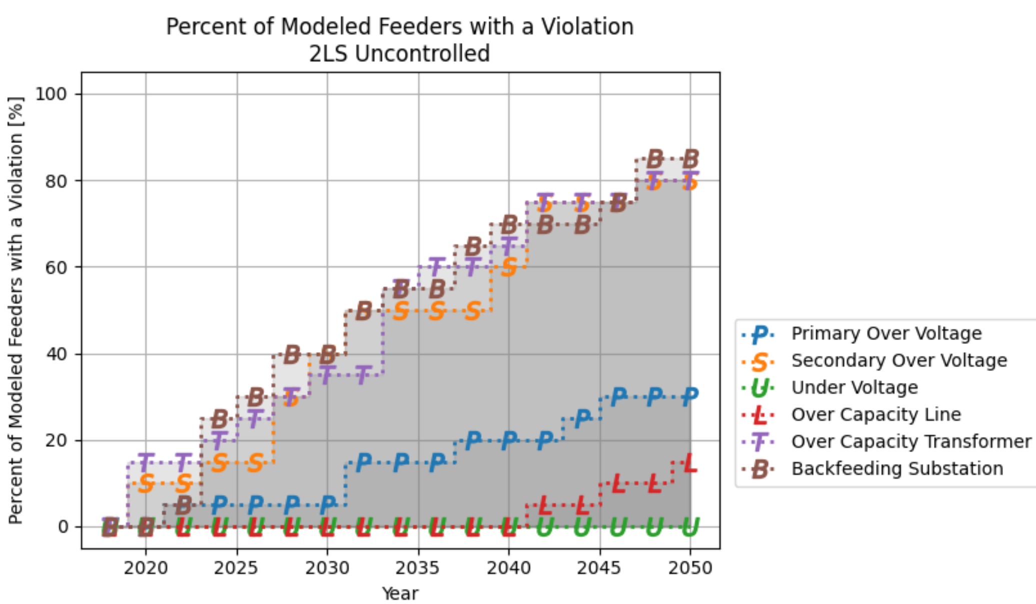

Figure 255. All violations for the uncontrolled 2LS simulation

As with scenario 1LM, despite scenario 2LS reporting transformer overloads in 80% of modeled feeders by 2050, Figure 256 shows that, on average, less than 10% of service transformers experienced a violation. Overvoltage violations are more common in this scenario as the maximum percentage of overvoltages in 2050 is about 35% while the median is less than 10%. Overcapacity lines represented less than 3% of total modeled elements in all years.

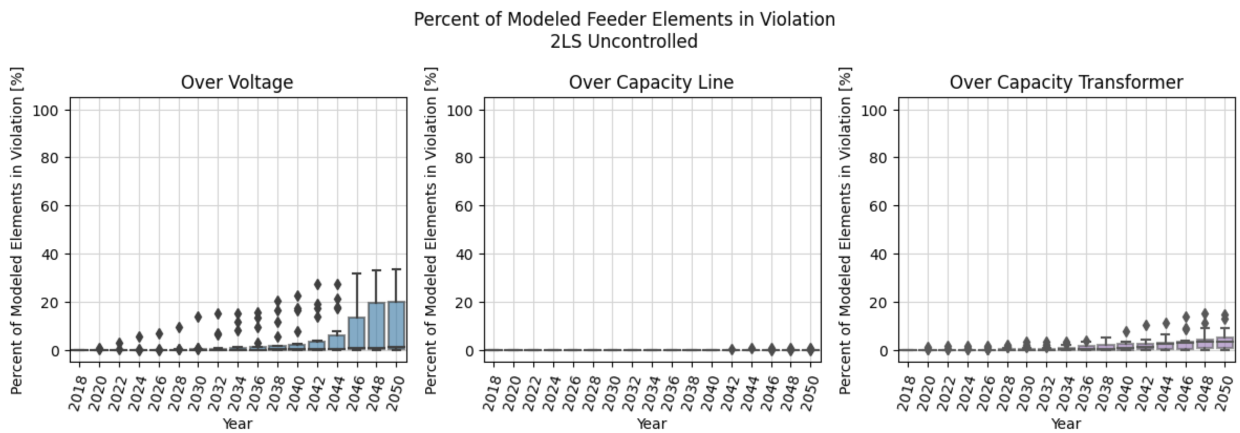

Figure 256. Percentage of feeder elements in violation for the 2LS uncontrolled simulation

Scenario 3LS reported the most violations in all categories. 50% of modeled feeders experienced backfeeding by 2026, which increased to 95% of feeders by 2050. Secondary overvoltages and over loaded transformer violations also followed similar trends being reported in over 50% of modeled feeders by 2028 and being seen in 90%–95% of feeders by 2050.

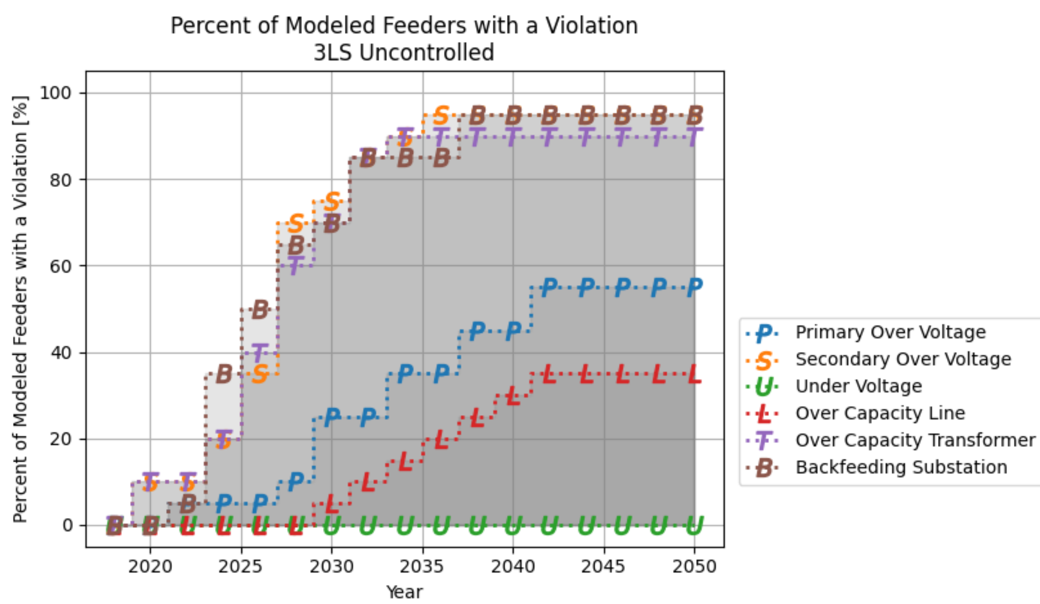

Figure 257. All violations for the uncontrolled 3LS simulation

Overvoltage elements were most prevalent in this scenario, as shown in Figure 258, the third quartile of elements in violation ranged from 18% to 42% by 2050 with a maximum of 70%. This means that in a single case, 70% of buses reported a voltage above 1.05 pu. Transformer overloading was also most common in this scenario where the median percentage of transformers being overloaded by 2050 was 15% with a maximum number near 40%. Line overloading was reported in 35% of feeders by 2050, but of those feeders, the overloading occurred in less than 10% of modeled line elements.

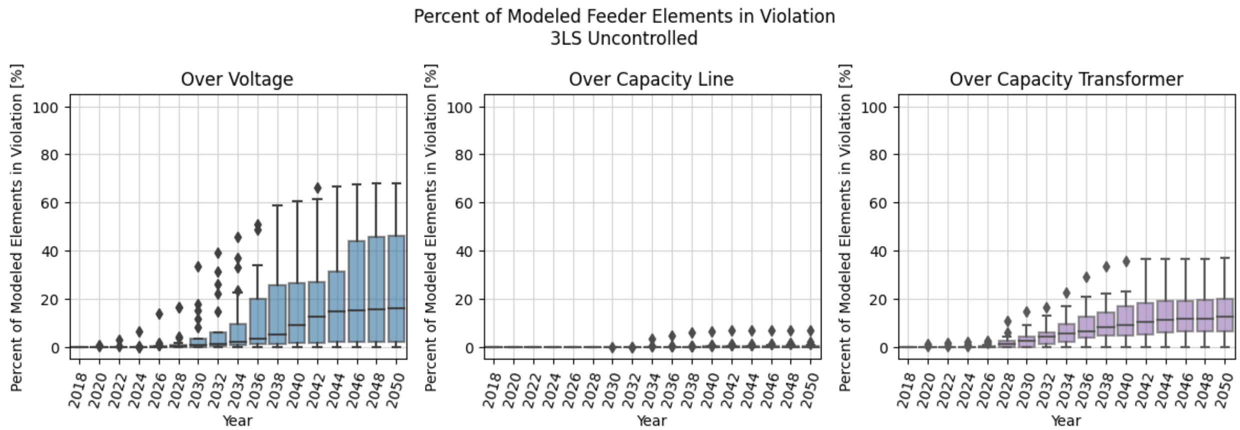

Figure 258. Percentage of feeder elements in violation for the 3LS uncontrolled simulation

11.5.1.3 Detailed Feeder Results

The impacts due to increased distributed PV had similar effects on most modeled distribution systems. Figure 259 shows common behaviors related to substation backfeeding. As the simulated year increases (plotted lines change color from orange to black), so does the amount of distributed PV. This in turn reduces the amount of active power required from the substation during the day. At some point, the distributed PV generates more real power than demand and the substation beings to absorb the excess (active power goes below 0). The two profiles shown are from high-voltage systems in the 2LS scenario where Feeder 19 (left) is a mixed commercial feeder with a midday demand peak, while Feeder 7 (right) is a residential feeder which has a demand peak at night.

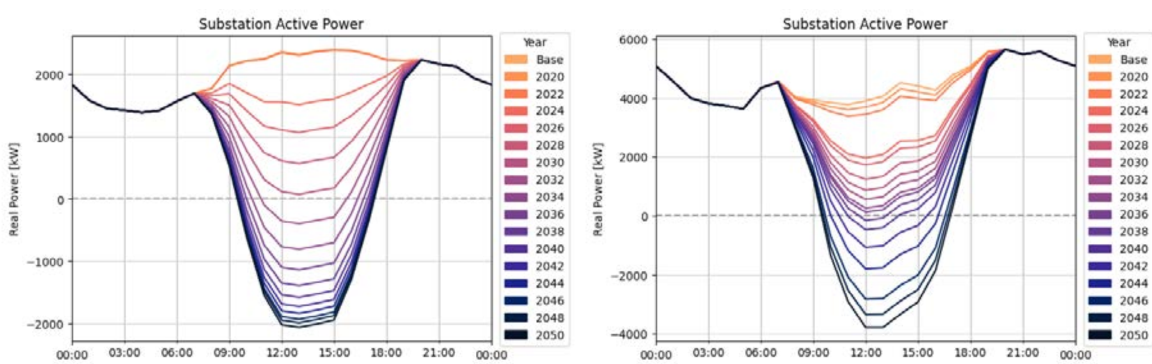

Figure 259. Substation delivered active power of Feeder 19 (left) and Feeder 7 (right) of the 2LS uncontrolled simulation

The minimum and maximum voltage profiles from both feeders are shown in Figure 260 where solid lines represent primary voltages, and dashed lines represent secondary voltages. In both cases, voltage violations occur during the day due to the increasing amounts of solar generation. Feeder 19 (left) has both primary and secondary violations while Feeder 7 (right) only reported secondary voltage violations. We note that Feeder 7's secondary voltages are extreme, reaching over 1.10 pu, which would require inverters to disconnect under the IEEE 1547 2018 standard.

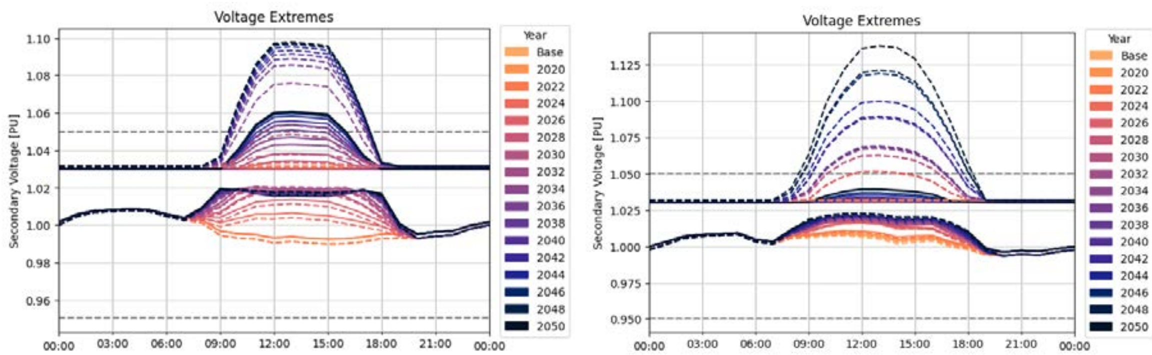

Figure 260. Primary and secondary voltage extremes of Feeder 19 (left) and Feeder 7 (right) of the 2LS uncontrolled simulation

Characteristic maximum line and transformer loading is shown in Figure 261. As PV penetration increased over the simulated years, midday line loading would initially decrease then later invert and increase again when as power flow reverses direction. This behavior corresponds to the PV generation meeting all feeder demand (lowest line loading) and then line loading increasing as backfeeding increases. Service transformer loading behavior is slightly different as the overloading typically occurs much faster than line loading and is more severe.

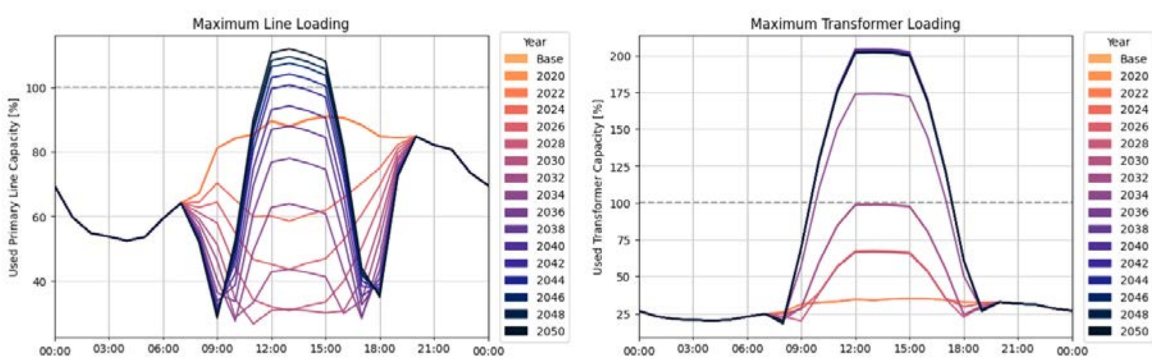

Figure 261. Maximum line (left) and transformer (right) loading of Feeder 19 during the 2LS uncontrolled simulation

11.5.2 Utility Storage Simulation

The utility storage simulation included allocation of utility-controlled storage twice the size of PV adoption to mitigate backfeeding. Additionally, both inverter control schemes were used for this simulation to better understand their effects.

11.5.2.1 Scenario Violation Overviews

As shown in Figure 262, the addition of utility-controlled storage handles all backfeeding violations for all scenarios for all years simulated.

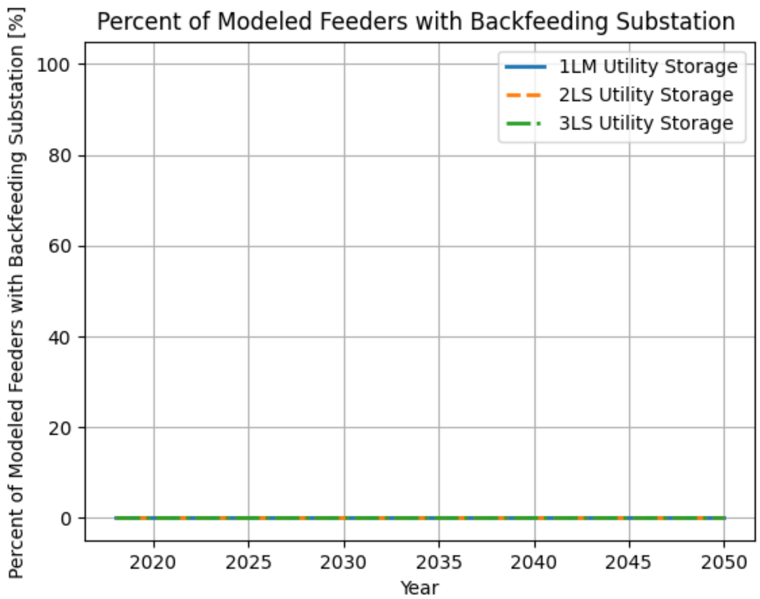

Figure 262. Percentage of modeled feeders with backfeeding violation in the utility storage simulation

Additionally, the utility storage simulation reduced the percentage of modeled feeders with a primary voltage violation in 2050 from 15%–55% in the uncontrolled simulation to 5%–25%. The percentage of feeders with a secondary overvoltage violation in Figure 263 were also slightly reduced to 50%–95% from 65%–95%.

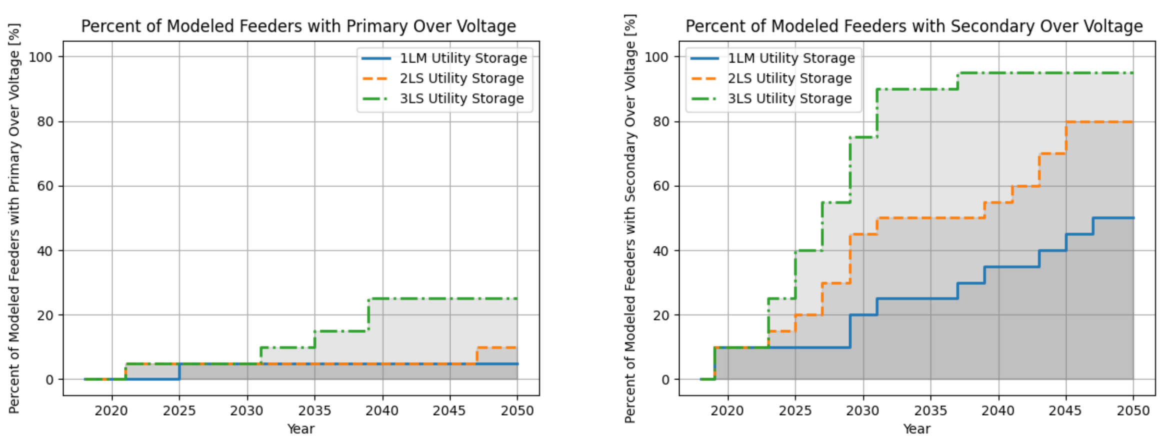

Figure 263. Percentage of modeled feeders with primary and secondary voltage violations in the utility storage simulation

Comparing Figure 252 with Figure 264, the percentage of feeders with a line overloading violation in 2050 was reduced to 10% in the 3LS scenario compared to 35% in the uncontrolled simulation. However, service transformer overloading increased slightly to 70%–90% of modeled feeders in 2050 with a violation compared to 60%–90% in the uncontrolled case.

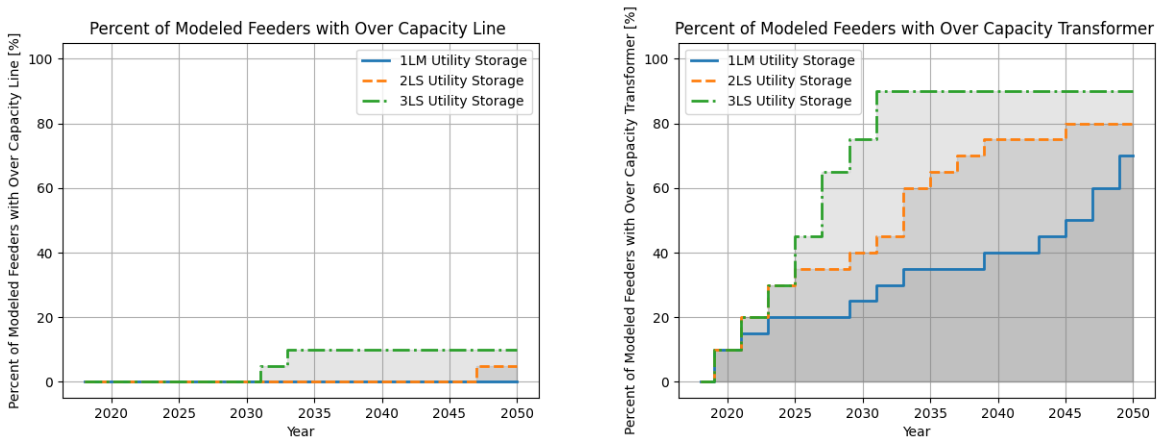

Figure 264. Percentage of modeled feeders with overloading violations in the utility storage simulation

11.5.2.2 Detailed Scenario Violations

The percentage of modeled feeders with a violation during the 1LM utility storage simulation is shown in Figure 265. Compared to Figure 253, the utility control completely eliminates backfeeding while also reducing voltage violations. However, the inverter controls introduced in this scenario slightly increase service transformer overloading to 70% by 2050 instead of 60% in the uncontrolled case.

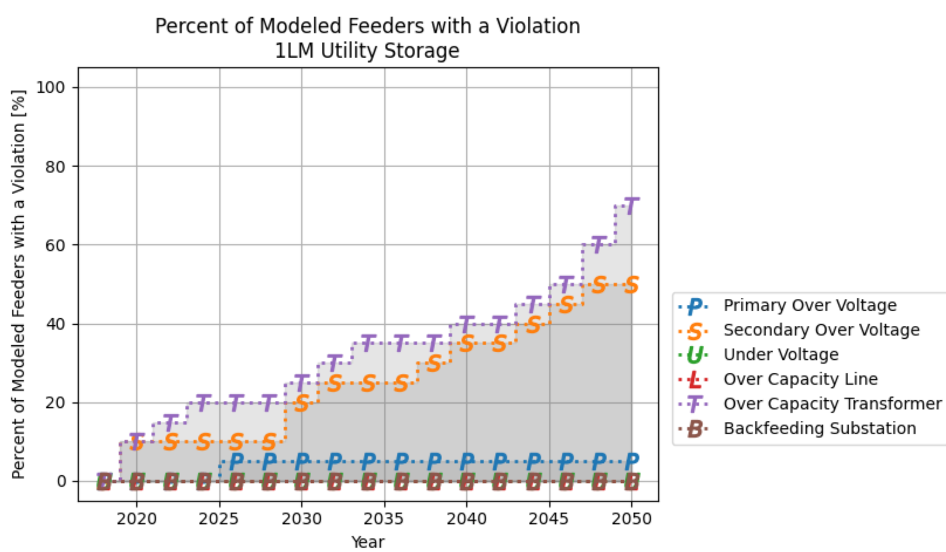

Figure 265. All violations for the utility storage 1LM simulation

Comparing the percentage of feeder elements with a voltage, line loading, or service transformer capacity violation in Figure 266 from the utility storage simulation to the uncontrolled simulation results in Figure 254 shows that only voltage violations are noticeably affected. Additionally, the utility storage simulation shows a large drop of voltage violations in 2050.

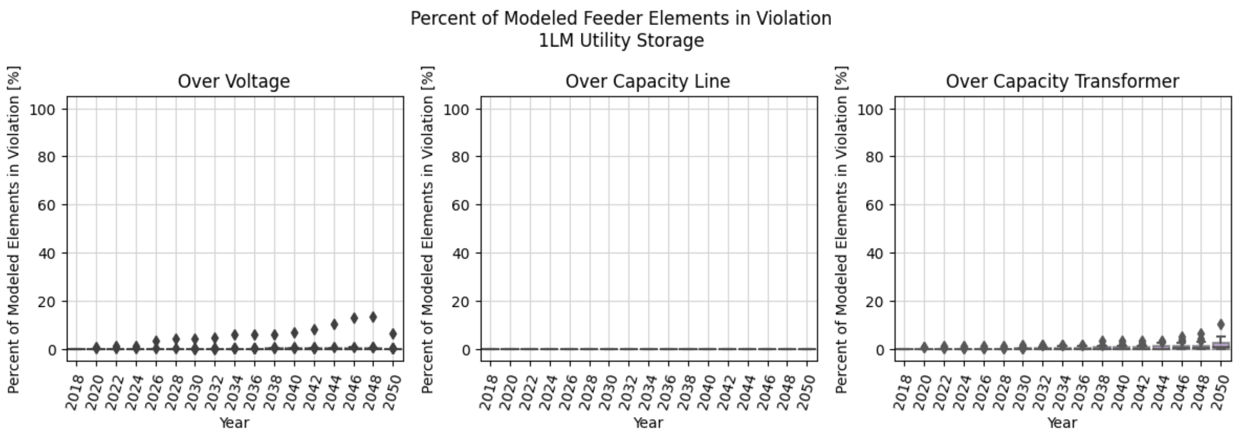

Figure 266. Percentage of feeder elements in violation for the 1LM utility storage simulation

The utility storage 2LS scenario results in Figure 267 have less voltage and line overloading violations than the associated uncontrolled scenario results in Figure 255. As mentioned before, there is no backfeeding in any utility storage simulation.

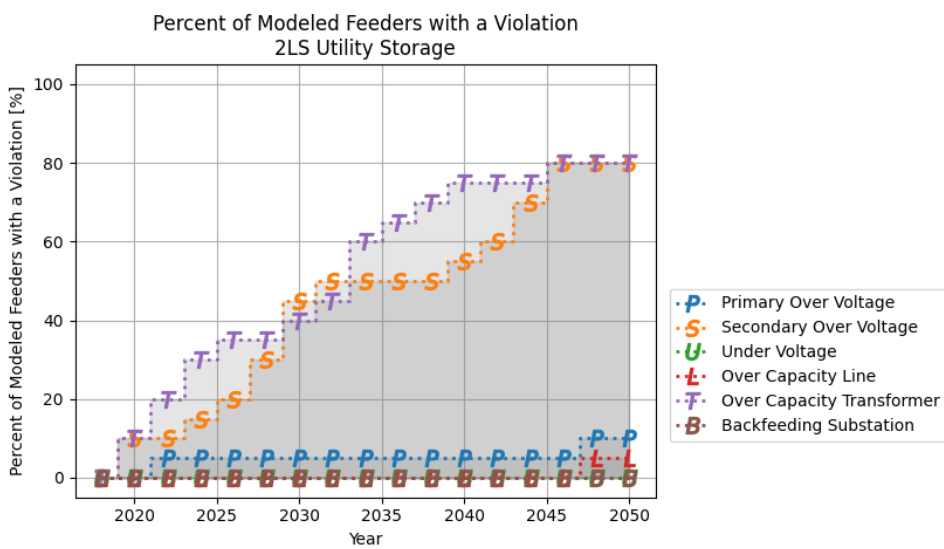

Figure 267. All violations for the utility storage 2LS simulation

Again, the percentage of overcapacity transformers was very similar between the uncontrolled and utility storage simulations. However, the amount of overvoltage buses is greatly reduced in the utility simulation shown in Figure 268, with outlier maximums being less than 10% for all years while the uncontrolled 2LS simulation results in Figure 256 had a maximum of 30% overvoltage buses by 2050.

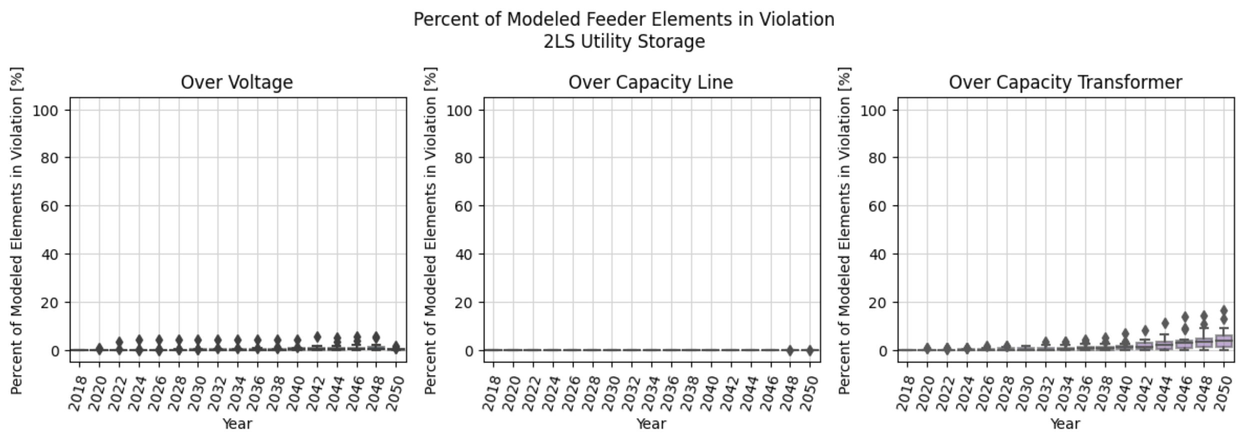

Figure 268. Percentage of feeder elements in violation for the 2LS utility storage simulation

Similar to previous utility storage results, the 3LS simulation had no backfeeding and also reduced primary voltage and line capacity violations. Figure 269 shows that the percentage of modeled feeders with a primary overvoltage was reduced to 25% from 55% in the uncontrolled case, and the percentage of feeders with an overloaded line dropped from 35% to 10%. Transformer overloading and secondary voltage violations did not change from being found in 90% and 95% of modeled feeders, respectively.

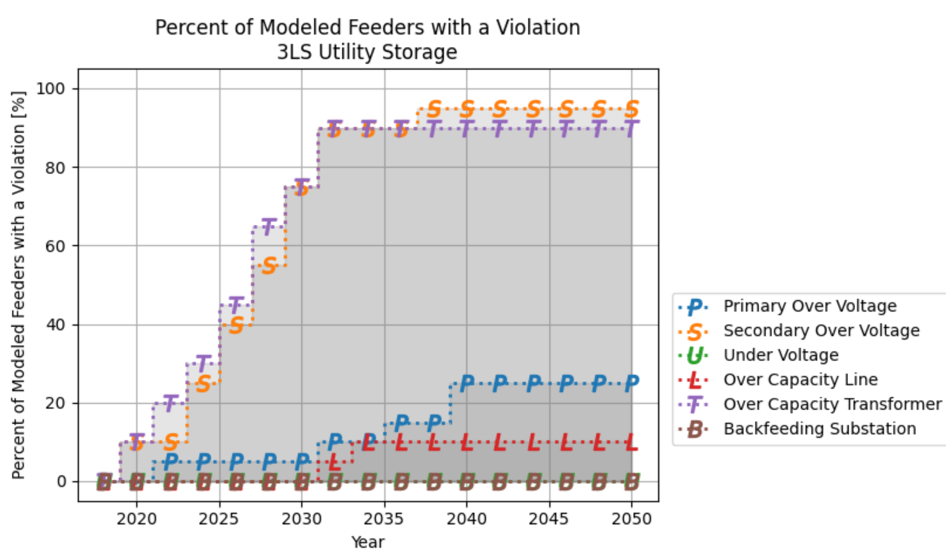

Figure 269. All violations for the utility storage 3LS simulation

Comparing percentage of elements in violation for the utility storage case to the uncontrolled case (Figure 270 to Figure 258) shows a large reduction in overvoltage buses, a minor change in overcapacity lines, and little to no change in overcapacity transformers. The voltage violation reductions are the most drastic with all maximums being less than 20% compared to the 70% 2050 maximum reported in the uncontrolled case.

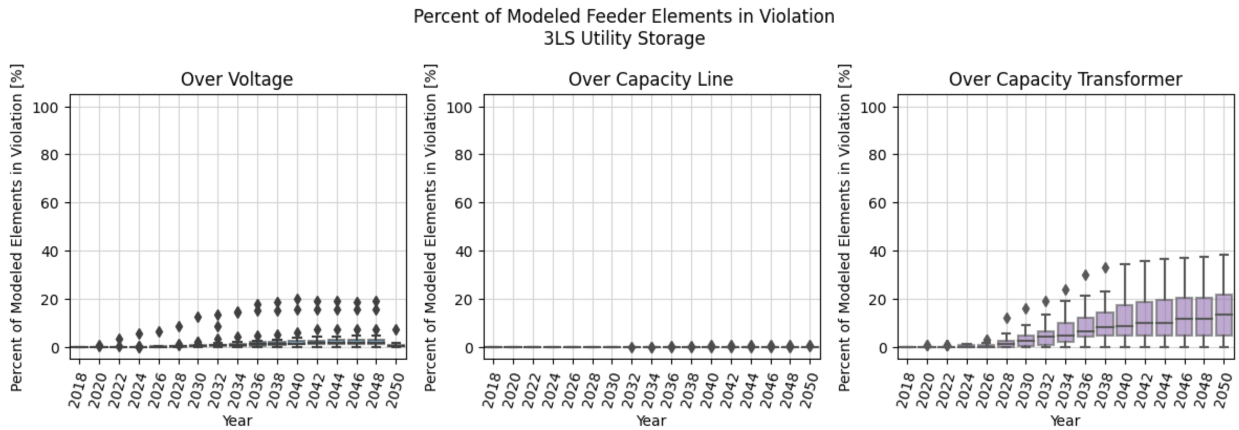

Figure 270. Percentage of feeder elements in violation for the 3LS utility storage simulation

11.5.2.3 Detailed Feeder Results

Substation backfeeding was resolved for all scenarios in this simulation case by applying the peak shave low control strategy to the utility-controlled storage. A characteristic response is presented in Figure 271 where the active power delivered from the substation is effectively limited at 0 kW due to the controlled storage charging. The SOC, shown in the right side of Figure 271 increases while substation backfeeding is being limited. The resulting stored energy is not deployed in this simulation.

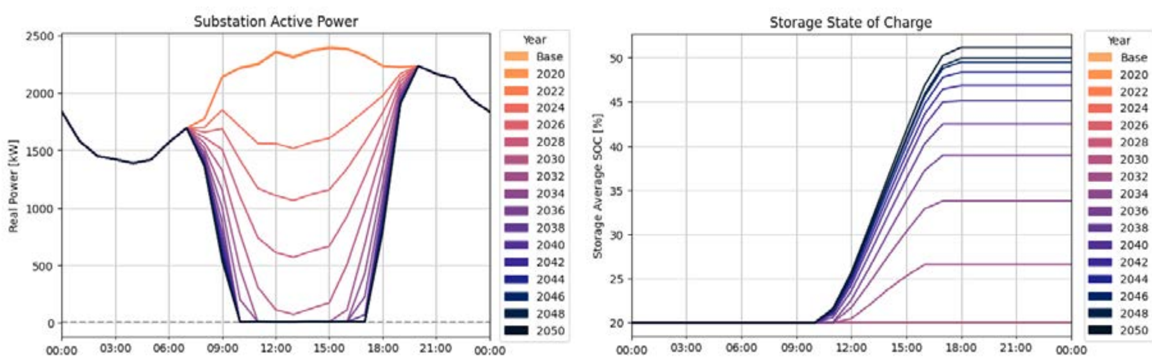

Figure 271. Substation delivered active power (left) and storage fleet SOC (right) from Feeder 19 during the 2LS utility storage simulation

The reduced line loading behavior associated with the utility storage simulation is shown in Figure 272. Compared to the uncontrolled case behavior in Figure 261, once the distributed PV begins generating more than demand, the loading peak does not increase beyond base case loading.

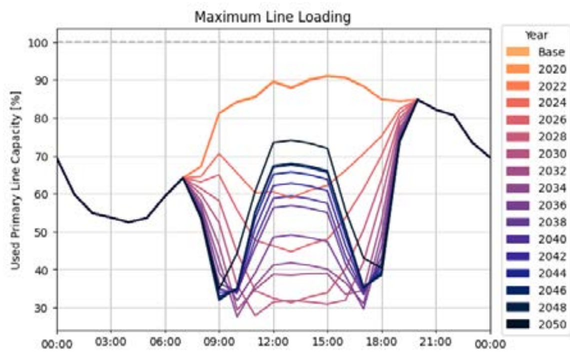

Figure 272. Maximum line loading from Feeder 19 during the 2LS utility storage simulation

11.5.2.4 Inverter Control Effects

Detailed voltage behavior is best observed by comparing the two inverter control schemes for this simulation. This is possible because the only difference between the utility storage and utility storage with aggressive PV simulation is the inverter control scheme. As shown in Figure 273, the percentage of feeders with an overvoltage primary violation in 2050 drops from 25% to 5% using the more aggressive inverter controls. The effect of the two controls approaches on the secondary system is less noticeable with only a 5% reduction in 2050.

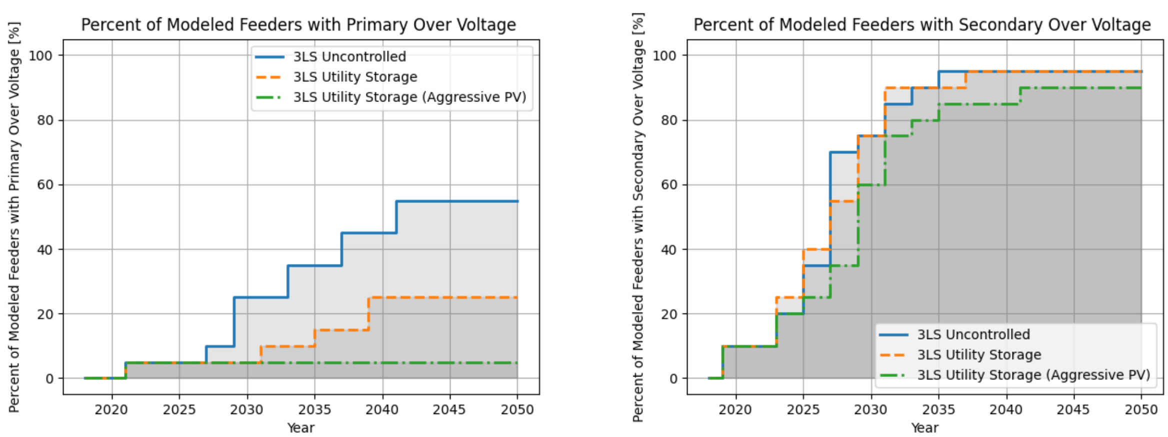

Figure 273. Percentage of modeled feeders with primary and secondary voltage violations using expected and aggressive PV inverter controls

While the aggressive control was found to reduce primary voltage violations, comparing Figure 274 to Figure 269 shows that an additional feeder had a line overload violation in 2050 using the more aggressive controls. This is caused by the aggressive control increasing the amount of reactive power and hence current flow. However, there is not a noticeable difference in the percentage of line elements in violation when comparing Figure 275 and Figure 270. There is a noticeable reduction in percentage of buses with an overvoltage violation when using the aggressive scheme as the 3LS case appears to only have maximums around 10% while the recommended results show maximums around 20%.

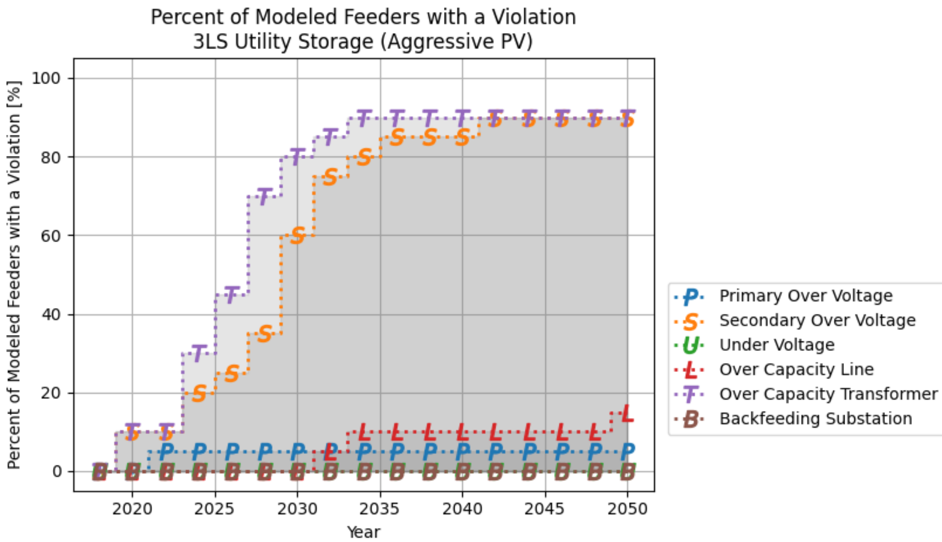

Figure 274. All violations for the utility storage aggressive PV 3LS simulation

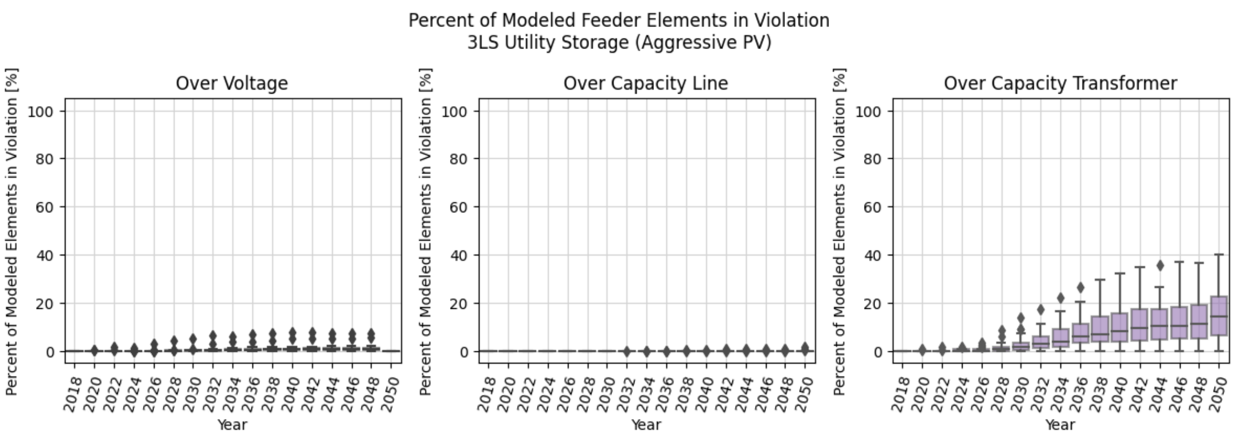

Figure 275. Percentage of feeder elements in violation for the 3LS utility storage with aggressive PV simulation

Detailed voltage behavior of the primary and secondary voltage extremes is shown in Figure 276. Both control schemes avoid primary voltage violations in the selected example, and the aggressive control further controls secondary voltages from going beyond 1.06 pu.

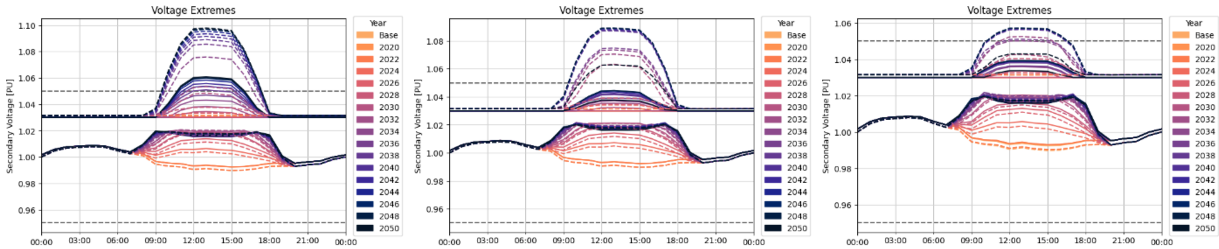

Figure 276. Primary and secondary voltage extremes of Feeder 19 with no control (left), recommended (center), and aggressive (right) PV controls during the 2LS utility storage simulation

The reduction in voltage is caused by the inverters generating inductive VARs to lower local voltage. However, to maintain the voltage set point at the feeder head, the substation will be forced to deliver more capacitive VARs. This increase in reactive power flow can most clearly be seen by observing the reactive power delivered from the substation for the uncontrolled case and the two control schemes in Figure 277. For the specific feeder shown, the substation initially delivers a peak of 825 kVAR in the uncontrolled case (left), but that value increases to nearly 1,400 kVAR and 1,750 kVAR in the recommended and aggressive PV controlled cases, respectively.

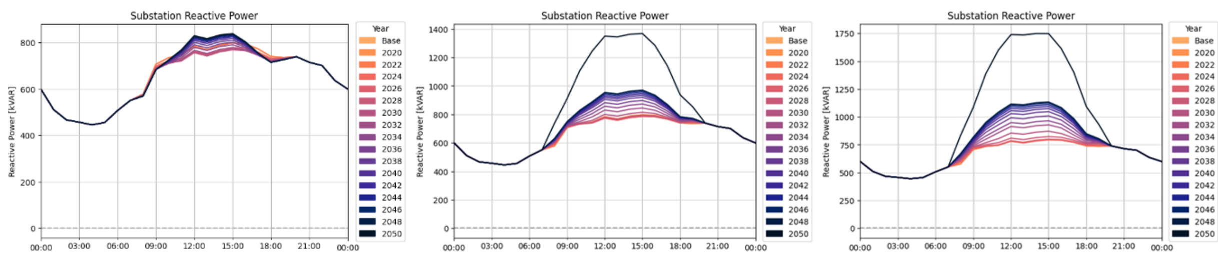

Figure 277. Substation delivered reactive power of Feeder 19 from the 2LS scenario during an uncontrolled simulation (left) and using recommended (center) and aggressive (right) inverter controls

The additional reactive power flow on the system is responsible for the previously mentioned increase in line overload violations and increases in transformer loading. Figure 278 presents the maximum transformer loading from Feeder 19 during the 2LS scenario. The initial maximum transformer loading is nearly 200% while the recommended controls increase that maximum to 350%. The aggressive control simulation allows restricts most years maximum below 200% until 2050 which rises above 300%.

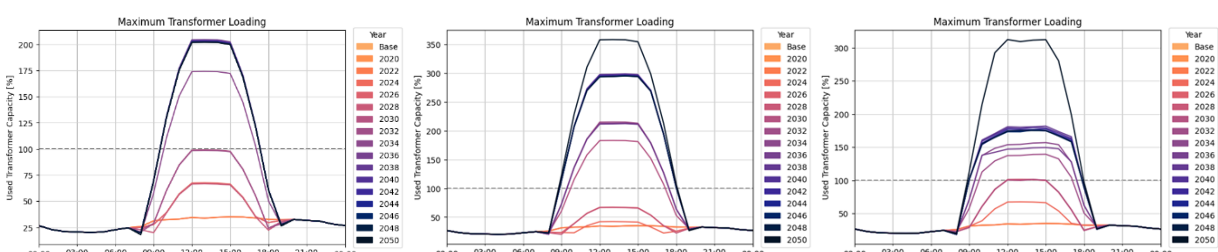

Figure 278. Maximum transformer loading of Feeder 19 from the 2LS scenario during an uncontrolled simulation (left) and using recommended (center) and aggressive (right) inverter controls

11.5.3 Distributed Storage Simulation

The distributed storage simulation assumes a 100% adoption rate of distributed storage with any additional PV system and the aggressive inverter control curves are applied.

11.5.3.1 Scenario Violation Overviews

Unlike the utility storage simulation, all scenarios experience backfeeding in the distributed storage simulations. Backfeeding appeared in later years compared to the uncontrolled simulation and to a lesser percentage of modeled feeders. Figure 279 shows that in 2050, 20%–65% of modeled feeders experienced backfeeding.

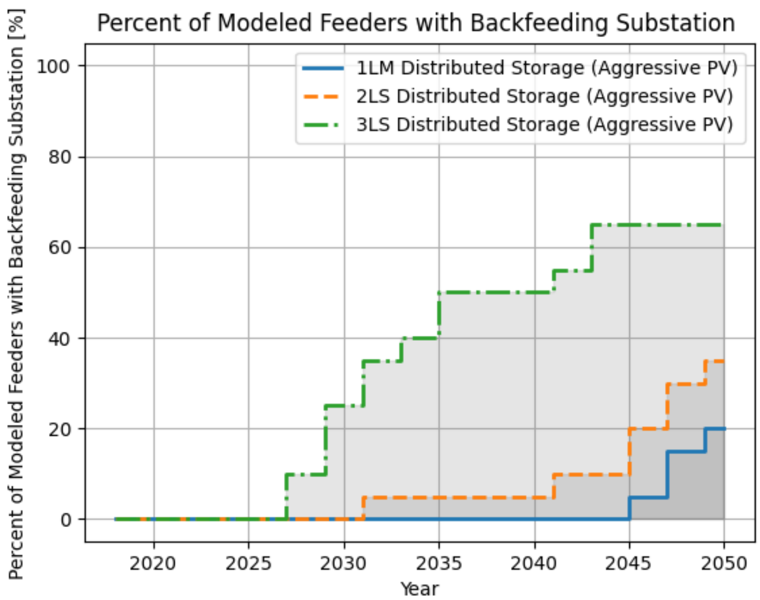

Figure 279. Percentage of modeled feeders with backfeeding violation in the distributed storage simulation

Comparing Figure 263 to Figure 280 shows that the distributed storage simulation reported less overvoltage violations than the utility control case. The reduction in secondary violations is largest in the second scenario with 35% of feeders experiencing a primary overvoltage in the distributed simulation, versus 80% in the utility storage simulation.

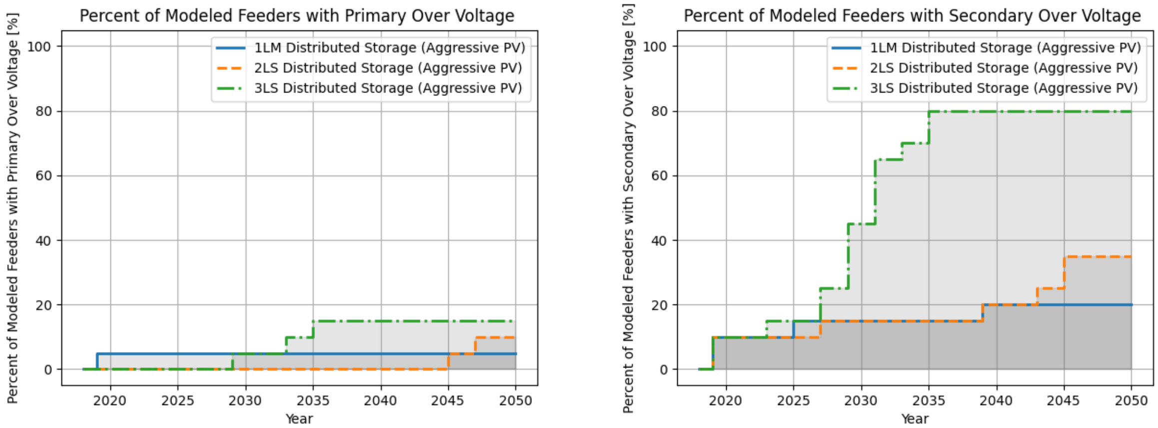

Figure 280. Percentage of modeled feeders with primary and secondary voltage violations in the distributed storage simulation

Figure 281 shows that in 2050 of 3LS, line overloading violations were reported in 30% of modeled feeders. This is slightly less than the uncontrolled simulation, but more than the utility storage simulation. Transformer overloading occurred in 10%–20% less modeled feeders compared to the utility storage simulation.

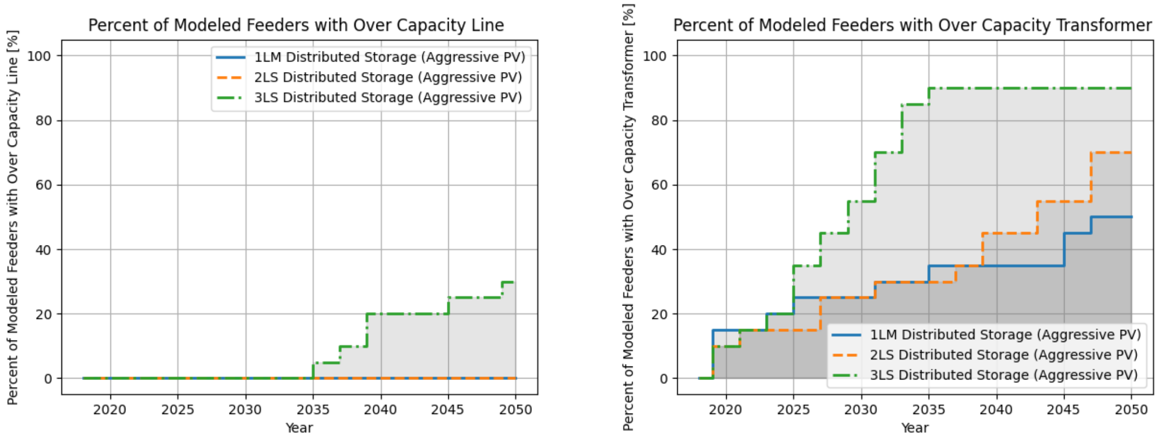

Figure 281. Percentage of modeled feeders with overloading violations in the distributed storage simulation

11.5.3.2 Detailed of Scenario Violations

Comparing Figure 265 to Figure 282, the 1LM scenario had less transformer overloading and secondary line overvoltages in the distributed storage simulation. However, backfeeding was first reported in 2046 and reported in 20% of modeled feeders by 2050. Additionally, Figure 283 shows that the distributed storage simulation had less than 5% of elements in violation for all simulated years and violation types.

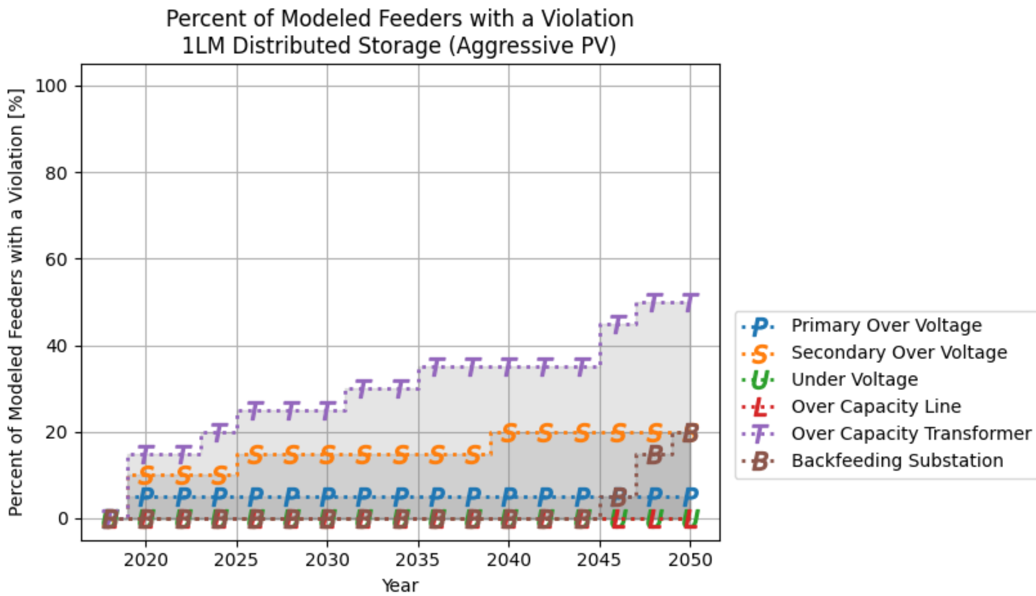

Figure 282. All violations for the distributed storage 1LM simulation

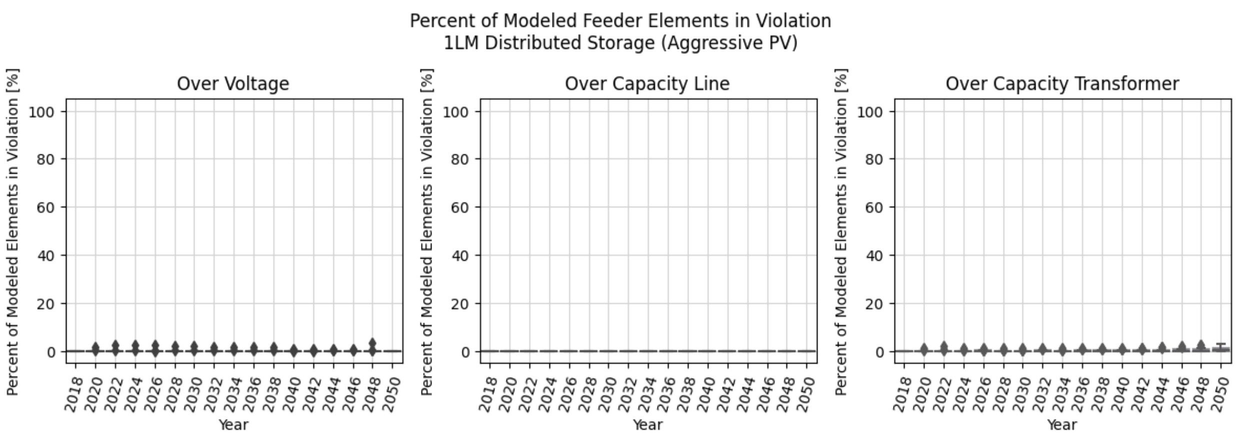

Figure 283. Percentage of feeder elements in violation for the 1LM distributed storage simulation

While backfeeding and transformer overloading was found in 80% of modeled feeders by 2050 in the 2LS scenario of the utility storage simulation, those same violations were found in only 70% and 35% of feeders using the distributed storage approach. Figure 284 shows substation backfeeding was first reported in 2032 and later found to be in 35% of the modeled feeders by 2050.

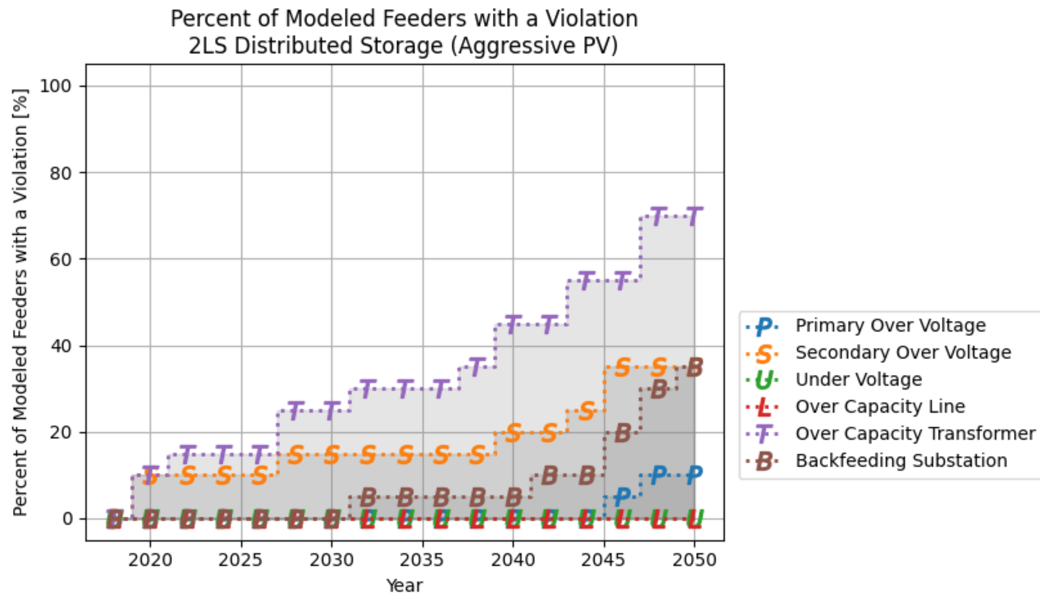

Figure 284. All violations for the distributed storage 2LS simulation

Figure 285 shows that the percentage of overvoltage elements appeared to be less than 10% for all years, and generally less than 3%. The percentage of overloaded transformers was generally reduced from the utility storage simulation, though the maximum amount reported in 2050 was near 20% in both cases.

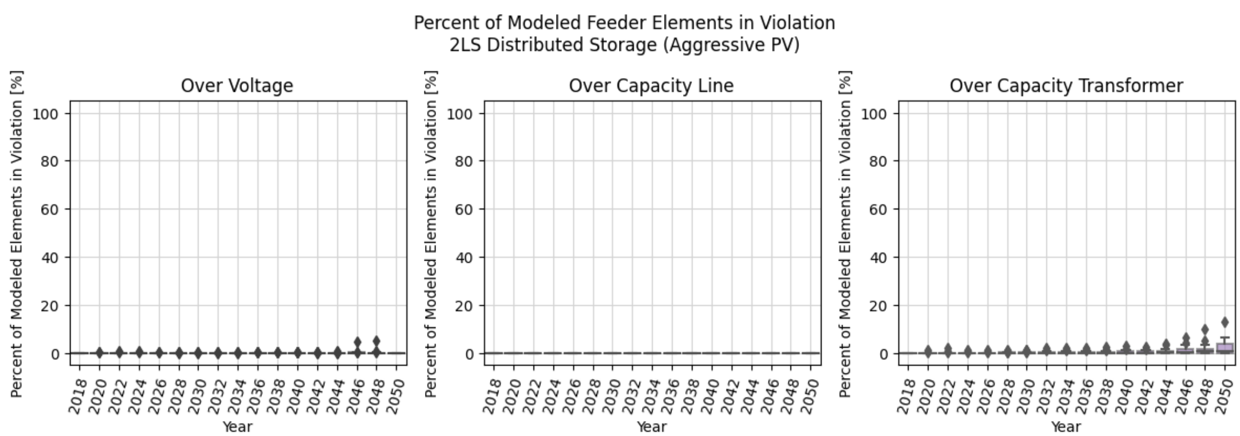

Figure 285. Percentage of feeder elements in violation for the 2LS distributed storage simulation

The percentage of transformer overloading violations shown in Figure 286 for scenario 3LS is the same as the utility storage simulation. The percentage of primary and secondary overvoltage violations was reduced by 10% and 15% respectively, in the distributed storage simulation. Line overloading violations increased in the percentage of modeled feeders in 2050 from 10% to 30%. Substation backfeeding was first reported in 2028 and by 2050, reported in 65% of modeled feeders.

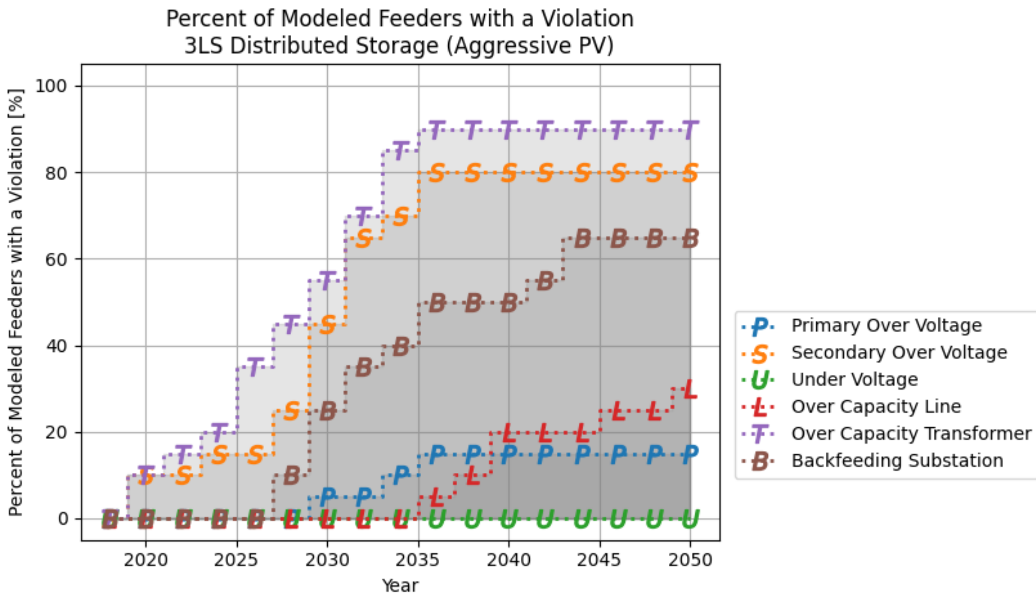

Figure 286. All violations for the distributed storage 3LS simulation

Compared to the percentage of elements in violation in Figure 270, Figure 287 shows a lower, and more concentrated spread of overcapacity transformers. The percentage of overvoltage elements was similar to the utility storage simulation while overcapacity lines was slightly higher.

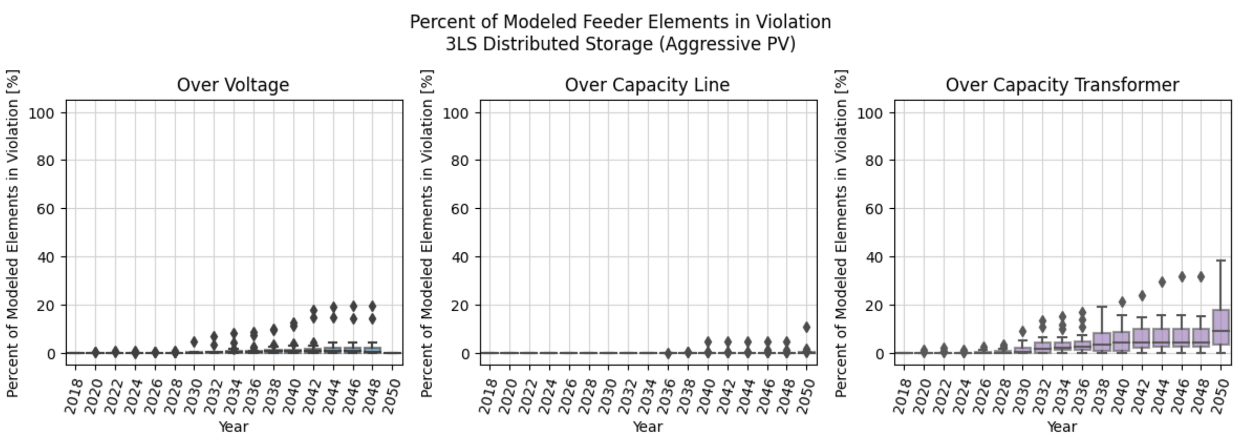

Figure 287. Percentage of feeder elements in violation for the 3LS distributed storage simulation

11.5.3.3 Detailed Feeder Results

A common issue with the distributed storage simulation is lack of storage capacity. Figure 288 presents a representative example of how, after a certain point during the day, the active power delivered from the substation began backfeeding (represented by negative values). In the presented case, this occurs as early as 15:00 in later year simulations. The cause of this is shown in the right side of Figure 288 where the storage SOC reaches 100%. The simulated years that do not reach 100% do not have backfeeding violations.

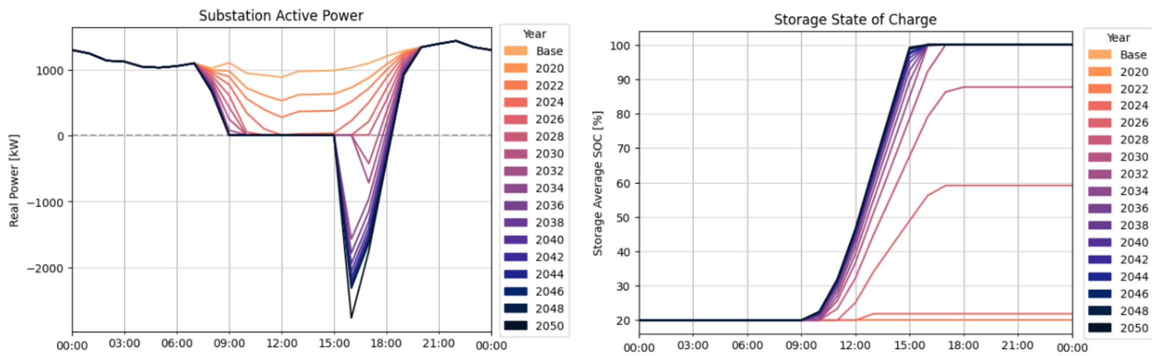

Figure 288. Substation delivered active power of Feeder 1 (left) and distributed storage SOC (right) from the 3LS distributed storage simulation

Figure 289 shows that line and transformers experience a spike in loading as storage capacity reaches 100% SOC. In the presented case, line loadings peak after 15:00 then sharply decline. Transformer loadings, shown on the right side of Figure 289, begin increasing slightly before 15:00 and deteriorate as the backfeeding caused by excess PV generation naturally reduces as the sun sets.

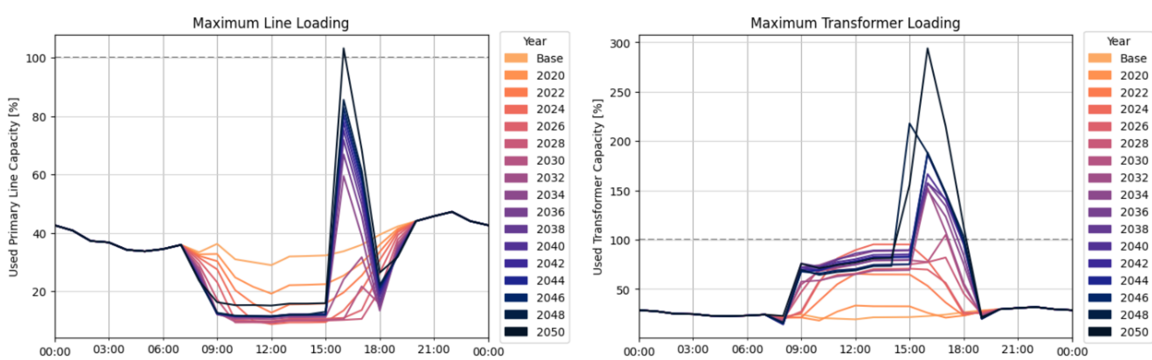

Figure 289. Maximum line loading (left) and transformer loading (right) of Feeder 1 from the 3LS distributed storage simulation

The left side of Figure 290 shows that while backfeeding is occurring, reactive power produced by the substation is also peaking. This peak is associated with the inverters control scheme. The voltage extremes presented on the right side of Figure 290 show violations occurring on both primary and secondary systems in later years during the same time as backfeeding is present.

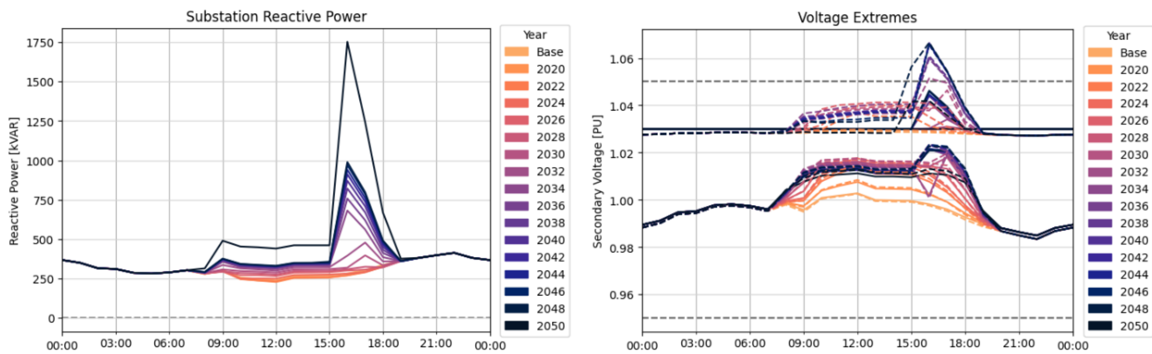

Figure 290. Substation delivered reactive power of Feeder 1 (left) and voltage extremes (right) from the 3LS distributed storage simulation

11.5.4 Combination Storage Simulation

The combination storage simulation contains the same storage allocation included in the distributed storage case, and half the storage amount from the utility case. Aggressive inverter controls are applied to all PV systems.

11.5.4.1 Scenario Violation Overviews

Like the utility storage case, the combination storage simulation contains no substation backfeeding in all years and scenarios. This is shown in Figure 291.

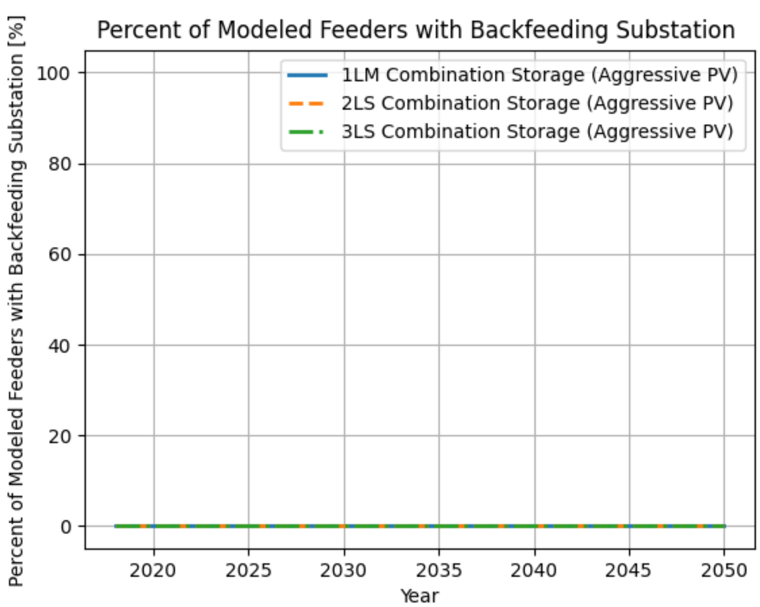

Figure 291. Percentage of modeled feeders with backfeeding violation in the combination storage simulation

The combination simulation was able to handle nearly all primary overvoltage violations. Figure 292 shows that in 2050, 25%–60% of modeled feeders still experienced an overvoltage on the secondary system. This is the smallest spread of voltage violations out of all simulations.

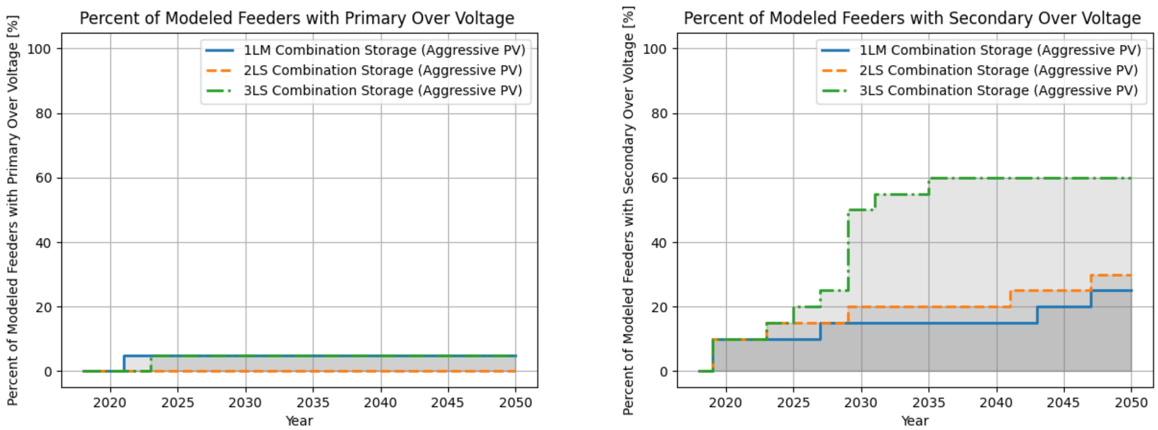

Figure 292. Percentage of modeled feeders with primary and secondary voltage violations in the combination storage simulation

Figure 293 shows that only 10% of modeled feeders reported an overcapacity line in 2050 in the combination storage simulation. This represents the fewest line violations in all simulations. Transformer overloading of the combination scenario was similar to the utility storage simulation.

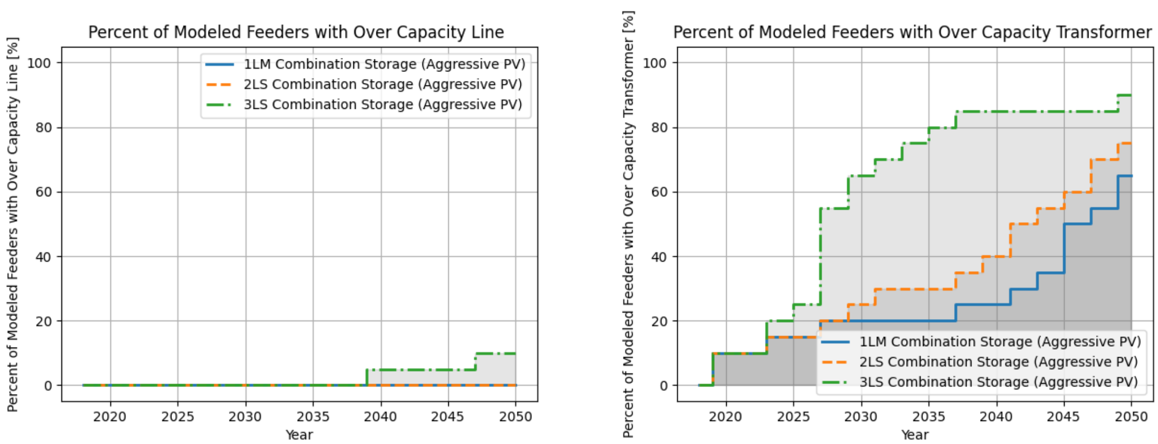

Figure 293. Percentage of modeled feeders with overloading violations in the combination storage simulation

11.5.4.2 Detailed of Scenario Violations

The percentage of modeled feeders with an overcapacity transformer in 2050 of Figure 294 was 5% less than the utility storage simulation, but 15% more than the distributed storage simulation in the 1LM scenario. Secondary overvoltage violations followed a similar trend. Figure 295 shows that all feeder elements in violation were less than 5% for all years of the 1LM scenario.

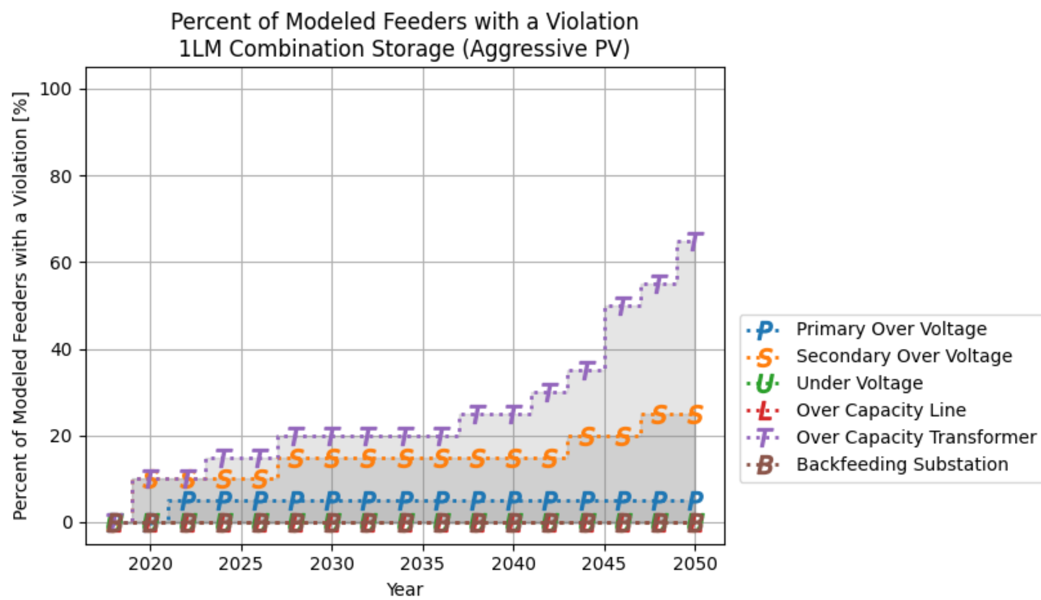

Figure 294. All violations for the combination storage 1LM simulation

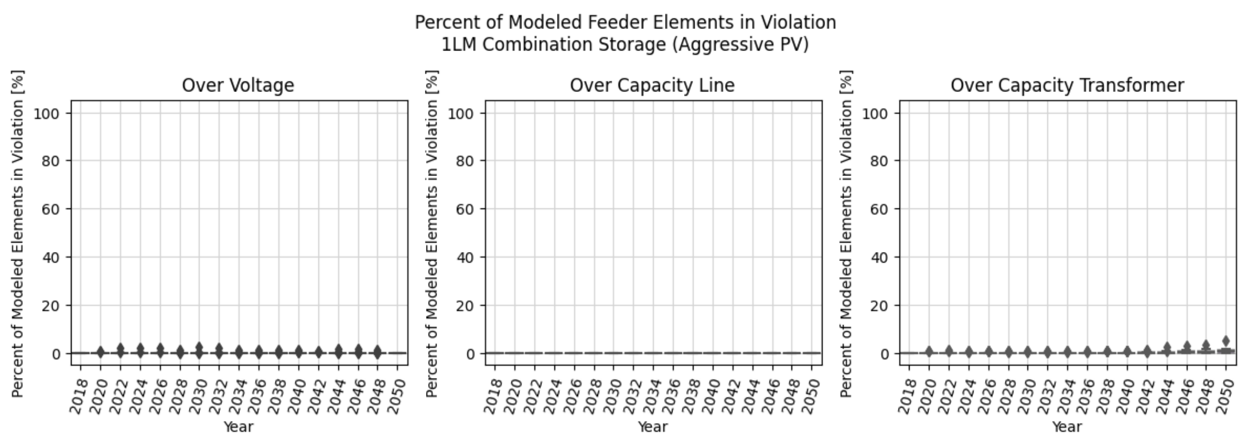

Figure 295. Percentage of feeder elements in violation for the 1LM combination storage simulation

Figure 296 shows that only transformer overloading and secondary overvoltage violations occurred in the 2LS scenario of the combination storage simulation. Compared to the utility storage simulation, transformer overloading was reduced by only 5% while secondary voltage violations were reduced to 30% from 80% in 2050. The percentage of elements in violation shown in Figure 297 was generally less than 5%, but up to approximately 10% of transformers in 2050.

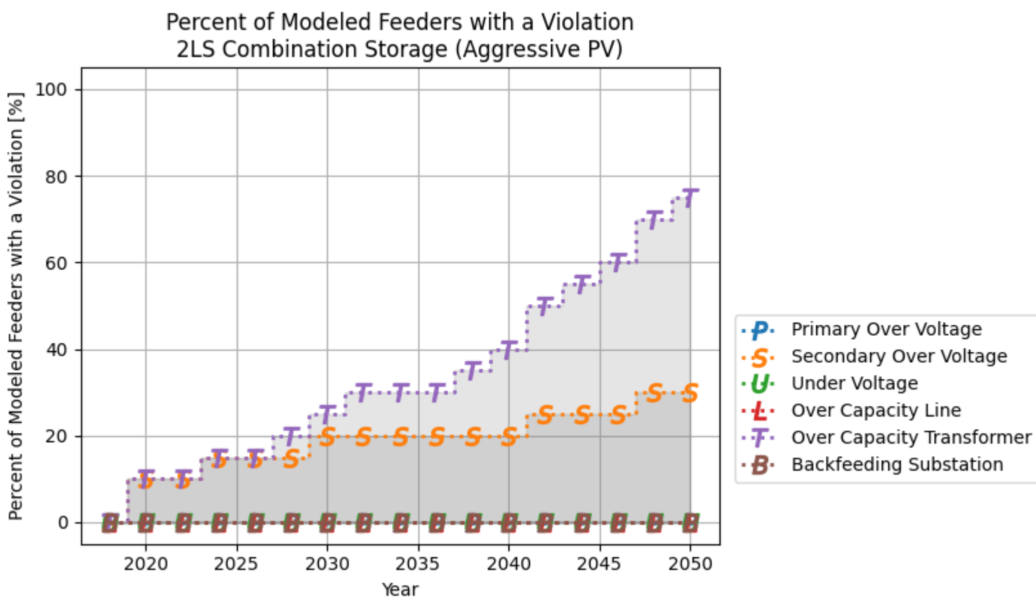

Figure 296. All violations for the combination storage 2LS simulation

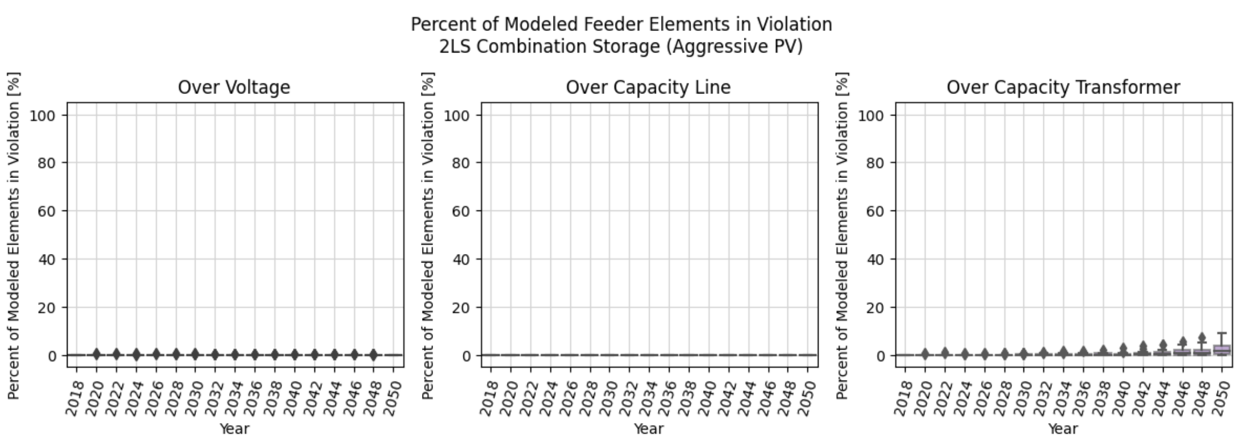

Figure 297. Percentage of feeder elements in violation for the 2LS combination storage simulation

The 3LS scenario had less feeders with a secondary voltage violation in the combination case than the utility and distributed simulations. Figure 298 shows that the number of feeders with a transformer violation is the same in 2050 as the disturbed simulation. The percentage of feeder elements with a voltage violation or an overloaded line was less than 5% for all years while the maximum percentage of overloaded transformers in 2050 was slightly more than 20%.

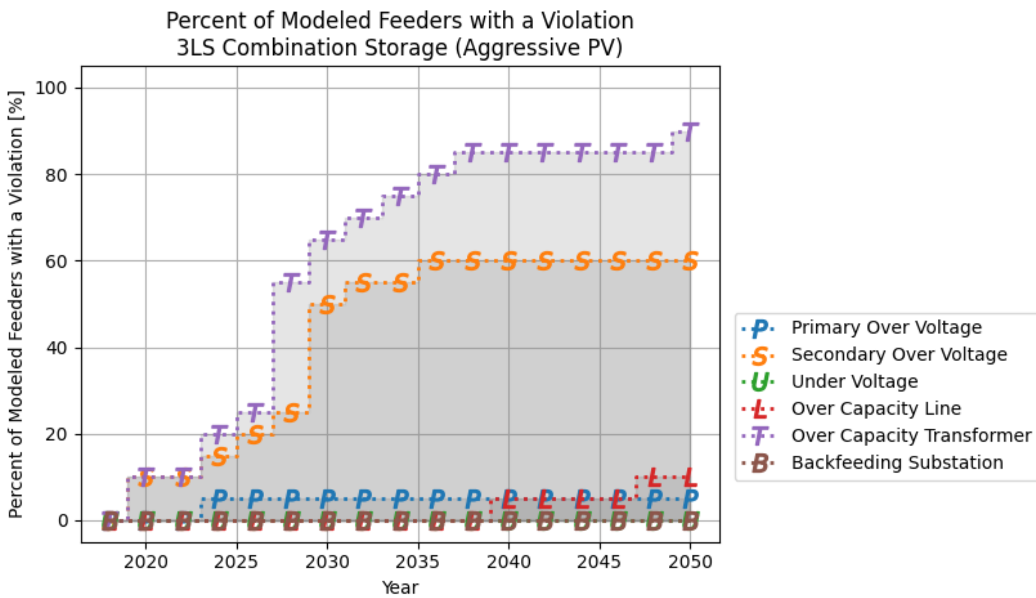

Figure 298. All violations for the combination storage 3LS simulation

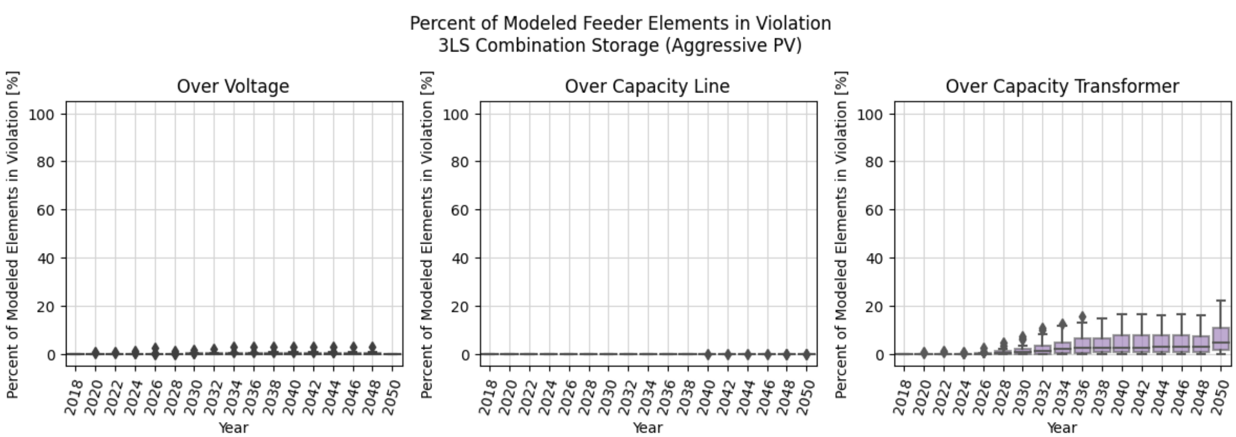

Figure 299. Percentage of feeder elements in violation for the 3LS combination storage simulation

11.5.4.3 Detailed Feeder Results

The amount and type of storage allocated for each year of the 3LS scenario for Feeder 1 is shown in Figure 300. The utility storage and combination storage simulations have approximately the same amount of total storage in each year; however, the amount of utility storage in the distributed simulation is about half the amount as the utility simulation. The distributed simulation has roughly half the storage as either simulation and consists primarily of systems that are 6 kW or 2.5 kW. It should be noted that in the utility simulation, only utility storage is inserted, thus the 'Total kW' line is on top of the 'Utility Storage' line in Figure 300.

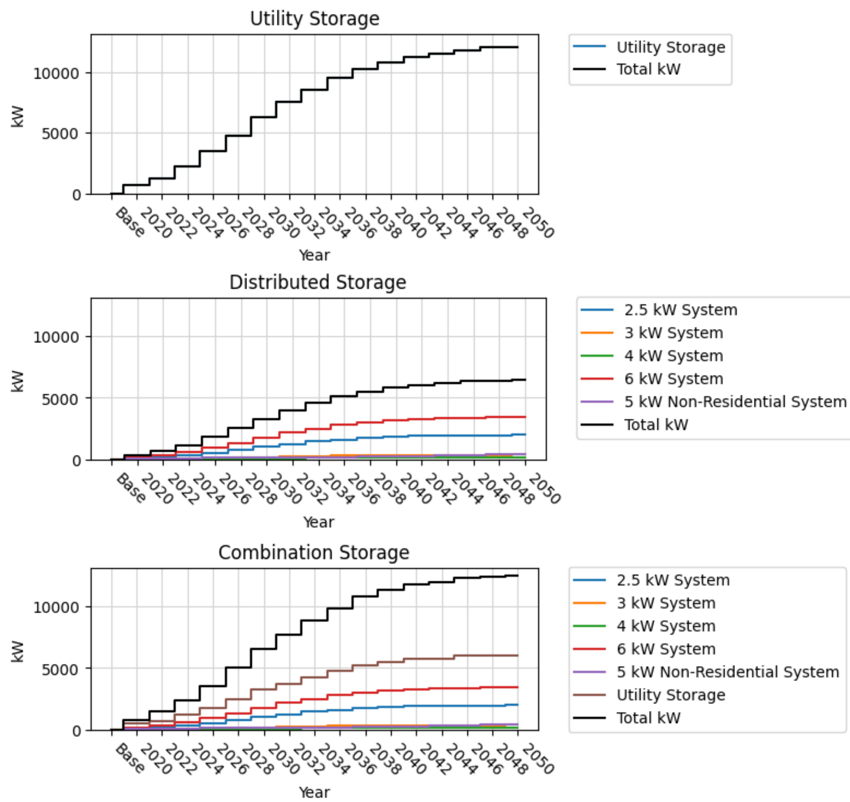

Figure 300. Storage allocation of utility, distributed, and combination simulations for Feeder 1

With adequate storage capacity, the substation does not experience any backfeeding. This is shown in Figure 301 and essentially the same behavior as the utility storage simulation shown in Figure 271.

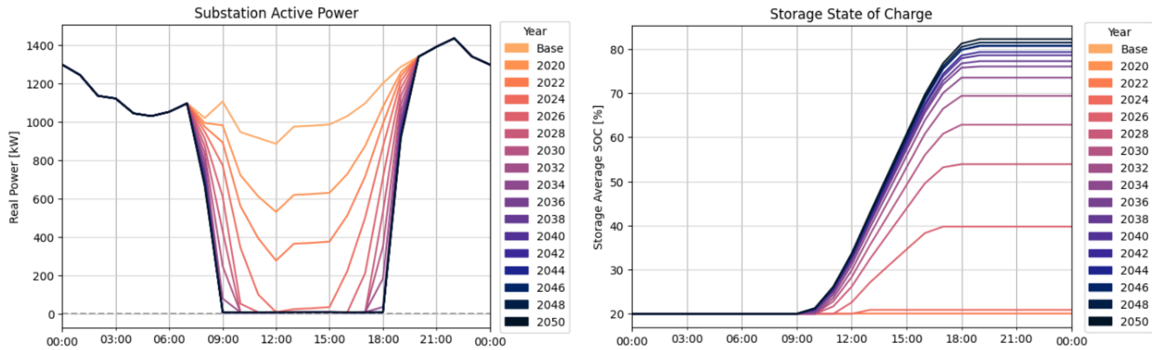

Figure 301. Substation delivered active power (left) and storage fleet SOC (right) from Feeder 1 during the 3LS combination storage simulation.

The primary and secondary voltage extremes from the combination storage simulation are shown in Figure 302. In this case, the aggressive inverter control scheme keeps the maximum voltage below 1.05 pu.

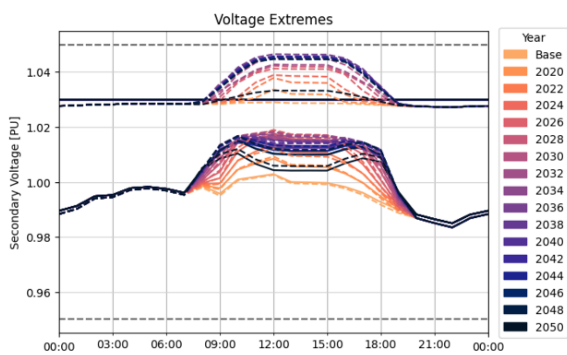

Figure 302. Primary (solid) and secondary (dashed) voltage extremes of Feeder 1 during the 3LS combination storage simulation

11.5.5 Feeder Class Comparisons

The feeder classification described in 11.3.1.2 allowed modeled feeder behavior of specific types to be compared. This section compares high-voltage feeders to low-voltage feeders, and residential feeders to commercial feeders. The only scenario presented is the uncontrolled 3LS as that includes the most violations caused by distributed PV adoption.

11.5.5.1 High and Low Voltage Comparisons

Figure 303 shows the percentage of modeled feeders with a violation for both high- and low-voltage feeders. The high-voltage feeders reported more backfeeding, transformer overloading, and secondary voltage overloads. The low-voltage feeders had more line loading and primary voltage violations. No feeders from either class had an under-voltage violation.

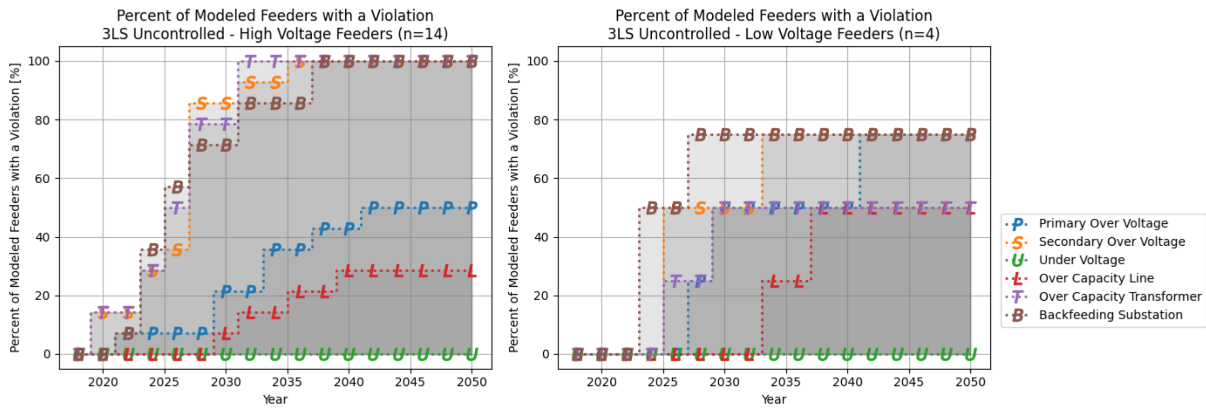

Figure 303. Percentage of high (left) and low (right) voltage feeders with a violation in the 3LS uncontrolled simulation

Figure 304 shows the percentage of feeder elements with a violation for both the high- and low-voltage modeled feeders. Lower voltage feeders typically had a higher percentage of overvoltage violations than high-voltage feeders. High-voltage feeders had more overloaded transformers than low-voltage systems. While line overloading was less than 10% for either voltage class, low-voltage feeders did have more overcapacity lines than the high-voltage feeders.

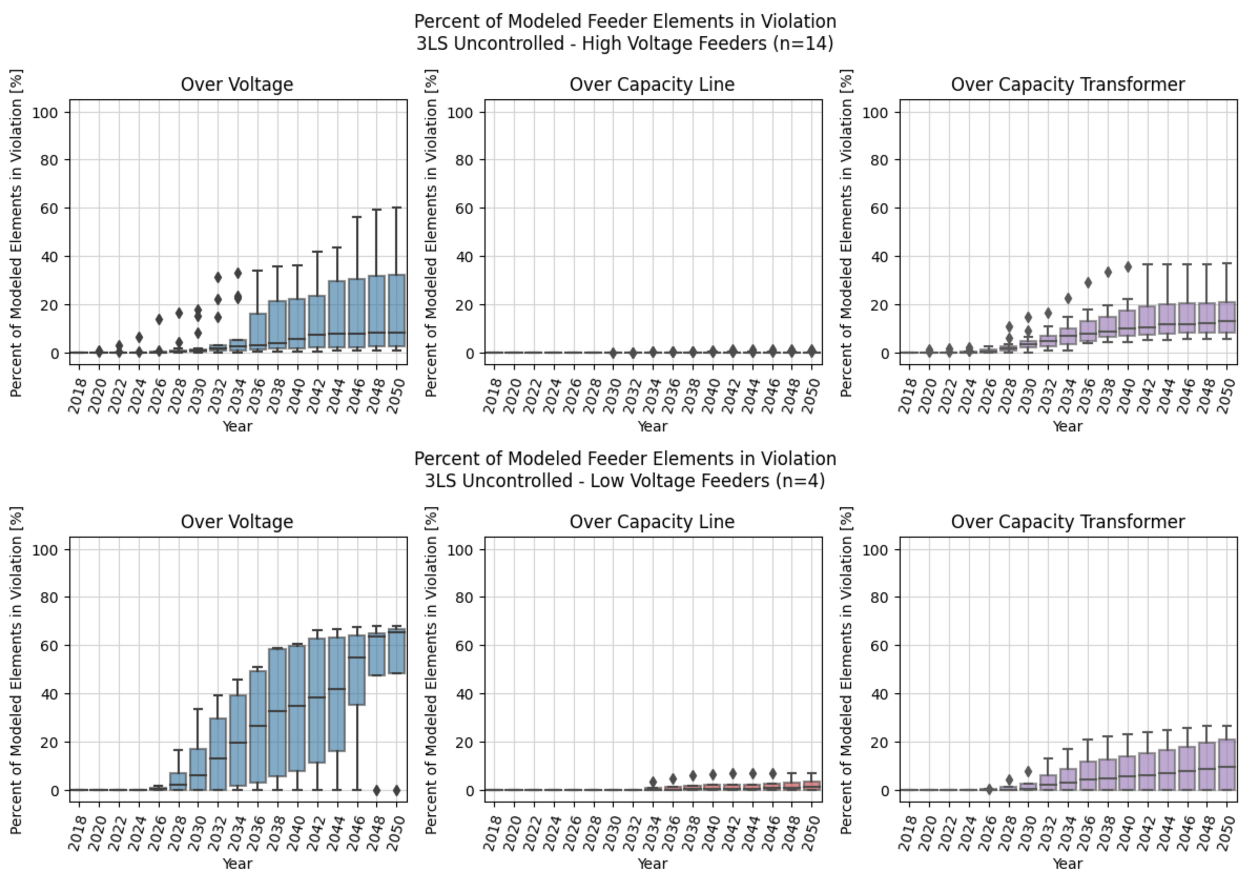

Figure 304. Percentage of high (top) and low (bottom) voltage feeder elements in violation for the 3LS uncontrolled simulation

11.5.5.2 Residential and Commercial Comparisons

The modeled residential feeders were more likely to encounter violations than the modeled commercial feeders. Figure 306 shows that by 2038 of the 3LS scenario, 100% of residential feeders had an over loaded transformer, secondary voltage violations, and substation backfeeding. Primary voltage violations were more common in both types of distribution system than line overloading.

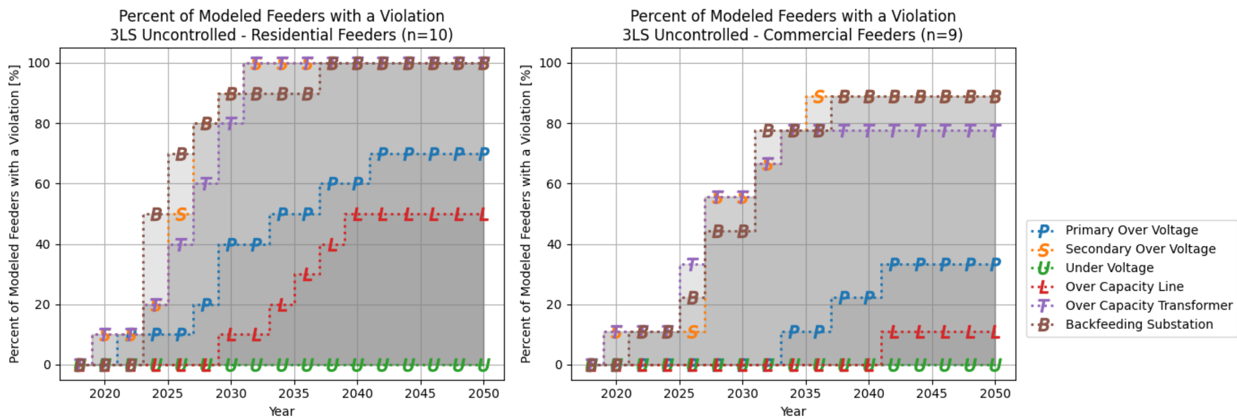

Figure 305. Percentage of residential (left) and commercial (right) class feeders with a violation in the 3LS uncontrolled simulation

Figure 306 shows the percentage of feeder elements in violation for residential and commercial feeders during the 3LS uncontrolled simulation. Residential feeders had many more elements in violation than commercial feeders. Residential feeders also had slightly more overcapacity transformers than the commercial feeders simulated. Both types of feeder had less than 10% of lines overcapacity, and typically less than 5%.

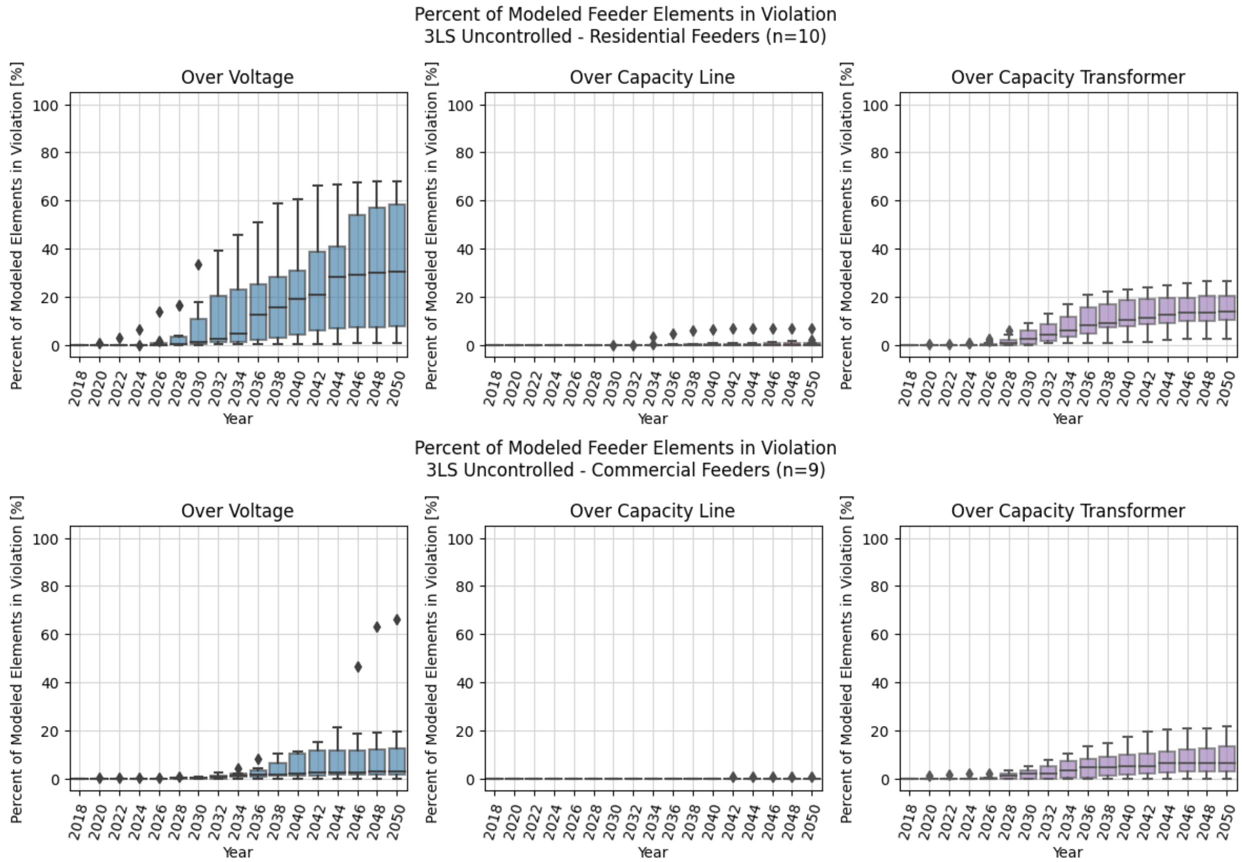

Figure 306. Percentage of residential (top) and commercial (bottom) class feeder elements in violation for the 3LS uncontrolled simulation

11.5.6 Result Summary

After reducing the voltage source set point and removing uncontrolled capacitors, the most common issues observed in the uncontrolled simulation were back feeding and overvoltage violations. The percentage of feeders with backfeeding appeared to follow similar trends as secondary overvoltage and transformer overloading violations in all uncontrolled scenarios—all of which increased as the amount of distributed PV increased. Scenario 3LS had the most severe violations while the 1LM scenario had the least number of violations. Secondary overvoltage violations were more common than primary overvoltage violations in all scenarios. Line overloading was the least common violation across all scenarios and no under voltage violations were reported.

By 2050, transformer overloading was seen in 60%–90% of modeled feeders with initial violations occurring in the first simulated year. The median percentage of transformer elements per feeder reporting a violation in 2050 ranged from 3% to 15% depending on scenario. Due to the large number of additional PV systems being put on a comparatively small number of service transformers, it is believed that many overloaded transformer violations could be avoided with a more controlled PV system allocation. This idea is further explored in Section 11.6.1.

The utility storage simulation resolved all backfeeding violations for all scenarios. Additionally, line overloading due to backfeeding was reduced. Primary voltage violations were reduced by using inverter controls schemes. However, the increased reactive power flow caused more loading in service transformers. The aggressive control scheme was shown to resolve more primary overvoltage violations than the recommended IEEE scheme, but further increased reactive power flow. In all simulations, storage assets were controlled only to charge with PV generation that exceeded immediate demand and not later used to power any grid-connected loads.

The storage adoption associated with the distributed storage simulation did not provide enough storage capacity for substation backfeeding to be prevented in all scenarios. Once a feeder began backfeeding, loading and voltage violations were observed. However, the percentage of feeder elements in violation was reduced compared to the utility storage case and reductions in the percentage of feeders with transformer and voltage violations was also reported.

The combination storage simulation did not report substation backfeeding in any year during any scenario. The amount of 2050 primary and line overcapacity violations was the least of any simulation. Secondary overvoltage violations were the lowest in the combination case of the 3LS scenario while similar to, or between, other simulation results for scenario 1 and 2. The total amount of storage in the combination simulation was about the same as the utility storage simulation but contained half as much utility storage.

High-voltage feeders were shown to have more backfeeding and transformer overloading than low-voltage systems. While high-voltage feeders may be more likely to have an overvoltage violation, low-voltage feeders tend to have more elements reporting on overvoltage. Line overloading was similar in high- and low-voltage systems, with 30%–50% system experiencing an overloaded line and less than 10% of line sections being overcapacity in the most extreme case.

Residential feeders were found to be more prone to violations of all types than commercial feeders. When high-voltage violations occurred on both kinds of system, a much larger percentage of the residential feeder buses would be overvoltage than commercial feeder buses. Transformer and line overloading were similar in both classes of feeder, though slightly more prevalent in residential systems.

11.6 Interpretation of Results

The modeled distribution systems required reducing the feeder-head voltage and removing any uncontrolled capacitors for the models to be simulated without violation when no PV systems were included. This means that the current distribution system must be updated before substantial additional distributed PV can be added if further violations are to be avoided.

Substation backfeeding, or reverse power flow, was the most-commonly encountered violation in the uncontrolled case. This occurred when distributed PV generation was larger than midday feeder demand. The peak demand times of residential feeders is typically in the evening when there is little solar production. To alleviate the imbalance of midday demand and PV generation, storage was investigated as a mitigation method.

The distributed storage simulation showed that even with 100% storage adoption with each PV system, there was not enough capacity to completely handle all backfeeding violations. The utility storage and combination storage simulations had twice the storage capacity as the distributed storage simulation and, as a result, were able to eliminate all substation backfeeding. The combination storage simulation split deployed storage equally between distributed and utility storage. This meant that only half as much utility storage was needed compared to the utility simulation as distributed storage resources made up the other half. This was meant to show the benefit of using both customer and utility assets to better manage the power system. When there was enough storage capacity to prevent backfeeding, most violations were avoided.

In all simulations, storage was used only to charge from excess PV generation such that substation backfeeding was prevented; however, the captured energy was not later reintroduced to the system to lower substation demand or any other purpose. While opportunities to handle and best apply this energy is beyond the scope of this work, a discussion on islanded feeder operation for resilience benefit is presented in 11.7.

The two inverter control methods presented both acted to reduce high-voltage violations. This was accomplished by inverters producing inductive VARs (equivalent to absorbing capacitive VARs) to reduce local voltage, but as a result, required more capacitive VARs to be generated at the feeder head. This increased reactive power flow on the system in turn increased line loading due to increased line currents.

While all additional PV systems had inverter controls, existing systems were uncontrolled. The effect of these systems on voltage violations was not studied in detail due to time constraints, but it is believed the uncontrolled systems are the main reason for continued voltage violations using aggressive inverter controls in simulations when backfeeding is not present.

Transformer overloading was somewhat obfuscated by the allocation of PV systems during simulation. Essentially, multiple PV systems could be placed on a transformer without considering the transformer capacity or connected load. This idea is further discussed in 11.6.1.

Line loading was identified in later years of the 3LS simulation, but generally affected a small percentage of lines. Any simulation that allowed storage to charge on excess PV generation reduced the amount of line overloading by providing multiple, and typically closer, sinks for excess power to flow to.

The extrapolation of feeder impacts from the 20 modeled feeders to the over 1,100 system feeders is difficult due to the limited number of feeders studied in detail. However, based on the data available, and the simulations performed, it was found that high-voltage systems were more likely to experience backfeeding and overvoltage violations than low-voltage systems. However, the percentage of elements experiencing an overvoltage violation was less in high-voltage systems than low-voltage systems. Residential systems were more prone to violation than commercial systems and experienced a much wider variety of overvoltage penetrations compared to commercial systems. The implications of these findings would require more time to fully analyze, as the full system is comprised of mostly low-voltage commercial and residential feeders.

11.6.1 PV Adoption and Service Transformer Capacity

The random allocation of PV systems on distribution feeders was seen to overload service transformers in the first simulated year of all scenarios. The random placement reflects a situation where the utility does not enforce any rules about connecting PV systems to the grid. However, it is desirable from an operations viewpoint that PV systems be limited by the amount of upstream transformer capacity. To that end, each year of adoption from all six scenarios was compared to the total service transformer capacity. The resulting PV adoption to service transformer capacity for all scenarios is shown in Figure 307. The ratio being less than 1.0 for all scenarios except 3LS and 3LM indicate there is theoretically enough service transformer capacity to handle predicted PV adoption if allocation of PV was optimized such that upstream transformers were not overloaded.

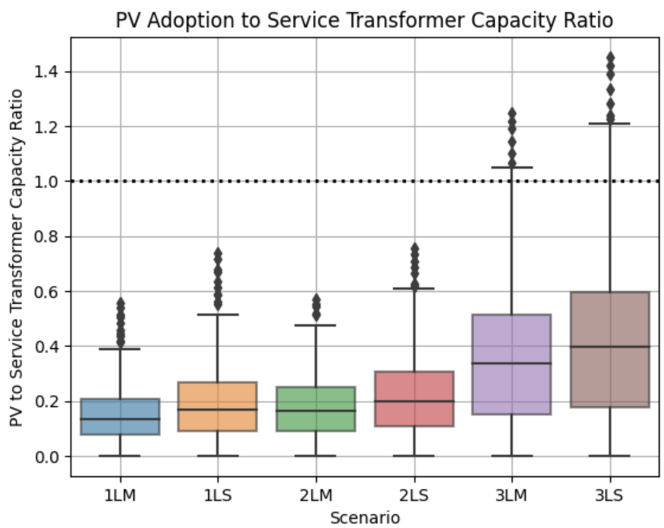

Figure 307. Ratio of PV adoption to service transformer capacity for all scenarios

A more detailed look at service transformer capacity to PV adoption for simulated scenarios is shown in Figure 308. The only scenario where there is insufficient service transformer capacity is 3LS from 2036 onward. These results suggest that if upstream transformer capacity was considered, overloaded transformer violations could largely be avoided until 2036 of the 3LS scenario.

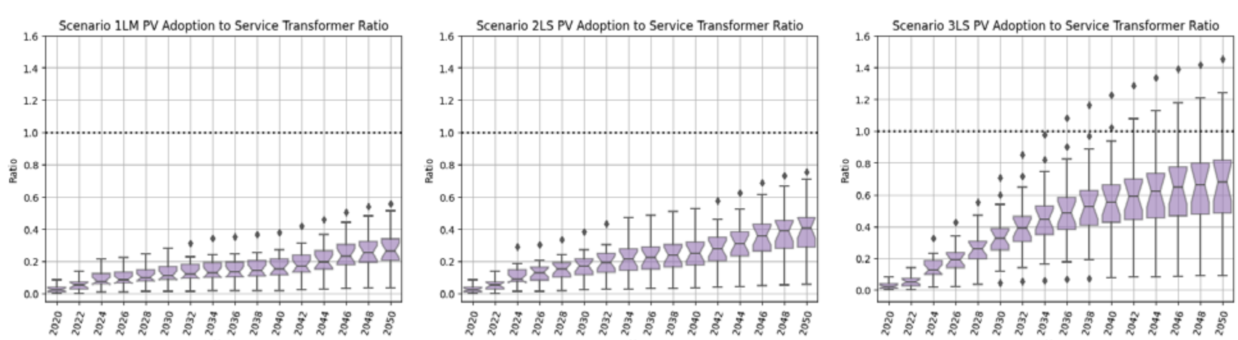

Figure 308. Yearly PV adoption to service transformer ratio of simulated scenarios

11.7 Additional Resilience Benefit to Distribution

Locations with PV and storage typically have some built-in ability to remain powered through black sky events. If utility storage was deployed with grid forming inverters, entire feeders could operate as an island without grid support. The exact duration of islanded operation would vary depending on many factors such as time of day and year, ability to charge batteries via PV, and actual demand.

For simplicity, this analysis looks at how long an entire feeder could be operated using the amount of storage described in the utility storage simulation, which was defined as 3-hr storage with two times the power capacity of adopted PV. The demand from the maximum demand day was summed, divided by the total amount of storage kilowatt-hours, and then multiplied by 24 hours. This was performed on the 20 modeled feeders to calculate the total number of hours each feeder could operate on storage alone. For all scenarios, the average value was plotted as Figure 309. By 2050, Scenarios 1 and 2 could likely support islanded operation for 6 to 9 hours, while Scenario 3 may be able to support over 14 hours of islanded operation.

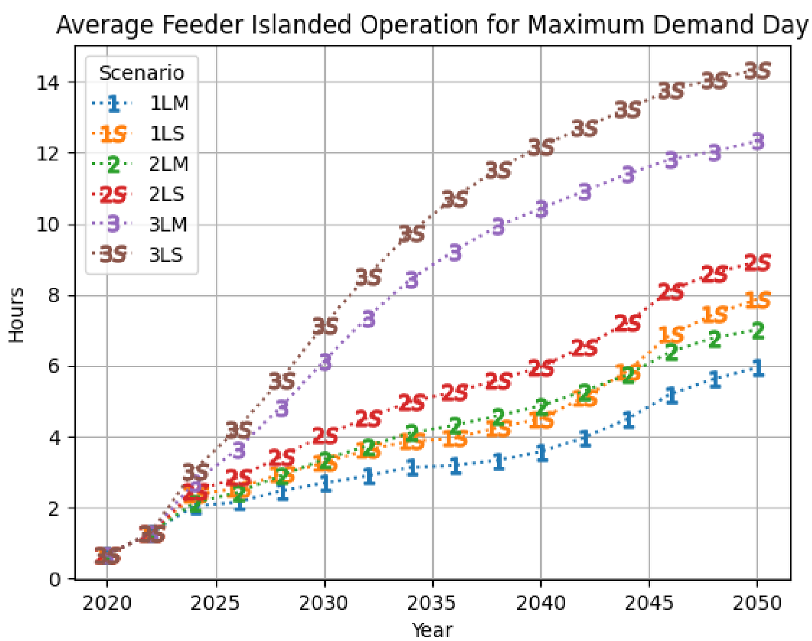

Figure 309. Average hours fully charged utility storage simulation could serve a feeder assuming maximum day demand and no additional charging of storage

For each simulated scenario, the same process was also performed for the minimum day demand with the results plotted as Figure 310. The minimum demand days allow for many more hours of possible islanded operation with a maximum of 48 hours in 2050 of the 3LS scenario.

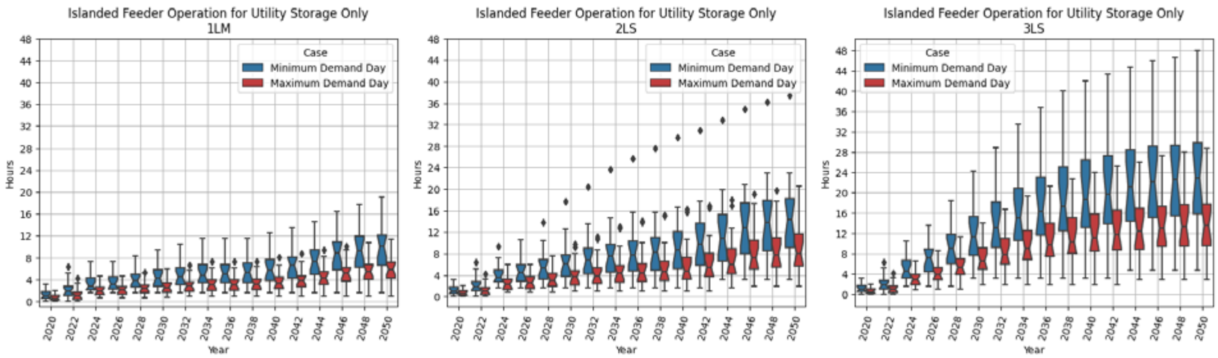

Figure 310. Details of estimated islanded operation time for both minimum and maximum demand days for simulated scenarios

11.8 Conclusions

In the scenarios simulated, distributed PV adoption in 2050 was forecast to be 4× to 10× the current PV penetration. The modeled distribution systems had to be modified to be run without voltage violations when no PV systems were included. This likely means the current system is experiencing high voltages that must be addressed before significant distributed PV resources can be properly grid-connected.

After initial feeder model modifications, the uncontrolled simulations showed that the predicted PV adoption will cause widespread and severe substation backfeeding as well as voltage violations. Violations in simulated year 2022 and 2024 may already be occurring on the system, but without proper monitoring of grid behavior, cannot be verified.

Deploying controlled 3-hr storage equal to twice the adopted PV amount was shown to eliminate backfeeding while inverter Volt/VAR controls were shown to mitigate voltage issues. For an optimized storage solution, it is likely each feeder would require a different amount of storage depending on demand characteristics and predicted PV adoption of that feeder.

Using customer storage resources to eliminate backfeeding will likely reduce costs to the utility while providing similar benefits than a utility storage solution alone. This can be seen by comparing the results from the Utility simulation to the Combined simulation. If utility deployed storage had grid forming capabilities, an immediate islanded operation resilience benefit could be realized while also preparing for future issues.

Immediate actions should be taken to plan for increased distributed PV. Some considerations to do so include updating the existing distribution system infrastructure to operate in the ANSI voltage range, installing more monitoring devices to gain better insights into current grid operations, standardizing control and interconnection requirements of grid-connected inverters, incentivizing customers to adopt and control storage assets, and beginning to deploy utility-scale storage on feeders that are likely to experience substation backfeeding.

12 Economic Impact Analysis

Peter Cappers[1], Michele Chait[2], Elena Smith[3], Harvey Cutler[4], Martin Shields[4], and Hwayoung Jeon[4]

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[2] Michele Chait LLC
[3] National Renewable Energy Laboratory
[4] Colorado State University

Section Summary

Two elements critical to understanding the implications of Puerto Rico moving to 100% renewable forms of electricity generation are cost and benefits: How much will this transition cost the citizens and businesses of Puerto Rico, and how will citizens be impacted financially from the transition? To address these questions, we first assess the narrow financial impact on the electric utility, as the key agent of change in the transition (Section 14.1); then expand our analysis to focus on the macroeconomic impacts related exclusively to investment in renewable generation technologies that contribute to meeting the Act 17-2019 goals (Section 14.2); and finally take the broadest perspective possible by quantifying effects in the Commonwealth due to all investment and expenditures incurred to meet the Act 17-2019 requirements (Section 14.3). A selection of key findings from this section is below, followed by actions stakeholders could take to advance progress toward Puerto Rico's energy goals. We identified these actions based on the results of our analysis, observations about Puerto Rico's current electric system, and knowledge of industry best practices.

- **Retail Rates Analysis:** The responsibility for implementing the requirements of Act 17-2019 will largely be borne by the Commonwealth's electric utility, PREPA, and its various third-party managed operating companies. This combined utility entity will incur additional costs to procure, maintain, and operate the transmission, distribution, and generation systems in Puerto Rico. However, the movement to 100% renewables will also result in savings of certain other utility costs, particularly fossil fuel. The retail rates component of the economic impact analysis quantifies how not only the costs of providing electric utility service to customers but also retail electric rates will change with the achievement of the Act 17-2019 goals.
- **Gross Macroeconomic Analysis:** The direct investment in utility-scale wind and solar resources as well as residential and nonresidential solar PV systems will affect not just Puerto Rico's electric utility but the broader economy as well. This more narrowly focused macroeconomic impact analysis quantifies the jobs, earnings, gross domestic product (GDP), and economic output of the Commonwealth related to investment in these specific forms of renewable generation technologies that contribute to meet the Act 17-2019 goals.
- **Net Macroeconomic Analysis:** To fully achieve the Act 17-2019 goals, Puerto Rico will not only invest in several different types of renewable energy resources but will also spend money on other supporting industries and sectors of the economy. In addition, the feedback effects associated with these investments and expenditures (e.g., electric utility rate changes) will further impact the economy. This more expansive macroeconomic impact analysis takes a much broader perspective to quantify the jobs, earnings, and household income effects in the Commonwealth due to all investment and expenditures incurred to meet the Act 17-2019 goals.

All three of these analyses use a subset of 6 of the 12 PR100 scenarios and variations presented in Table 26 (Section 6.1.7, page 183). These six scenarios and variations were selected to represent the full range of impacts and to allow more focused comparisons associated with key drivers. These six scenarios and variations are 1LS, 1LM, 1MS, 2LS, 3LS, and 3MM (see Table 26, page 183 for the complete list of scenario variations and identifiers in PR100). The analysis described in this section integrates the economic costs and benefits associated with outputs from analyses described in Sections 5 (page 117), 6 (page 173), 7 (page 186), 8 (page 209), 9 (page 241), and 11 (page 347).

Key Findings

Utility Retail Rate Analysis (Section 12.1)

- To achieve a more reliable and stable energy system, the utility experienced a substantial increase in its revenue requirement (48%–57%) between 2020 and 2025, resulting in large all-in average retail rate growth (66%–83%). The adequate generation fleet modeled met the 40% renewable portfolio standard. (Section 12.1.3)
- Between 2025 and 2045, the utility experienced a decline in its revenue requirement (9%–24%) driven by reductions in administrative costs and investments in less expensive generation resources that met interim RPS requirements. However, increasing levels of rooftop PV adoption caused retail sales to drop (-1% to -41%), resulting in all-in average retail rates that either dropped modestly (-8%) or increased substantially (34%). (Section 12.1.3)
- The utility's revenue requirement was increasingly dominated by sunk or fixed costs that did not vary in the short term with changes in retail sales, whereas the utility's collected revenue could vary in the short term with changes in retail sales because utility rate design relied heavily on volumetric energy charges set during rate cases. (Section 12.1.3)

Gross Macroeconomic Analysis (Section 12.2)

- Construction and installation efforts, which are nonpermanent, create more than 6 times the number of jobs and earn more than the operation and maintenance (O&M) efforts on average. However, O&M efforts are longer-lasting jobs with higher associated labor hours than temporary construction efforts. (Section 12.2.3)
- There is a dramatic boom-bust-boom-bust cycle in construction/installation jobs to initially meet the 2025 40% RPS requirement and later meet the 2050 100% RPS requirement. In contrast, there is considerably more stability in O&M jobs that steadily ramps up over time because of more energy assets being deployed over time. (Section 12.2.2)
- Higher levels of distributed solar adoption led to higher job creation both during the construction/installation phase as well as during the operation phase. However, the balance between O&M jobs created from distributed solar is 38% versus utility-scale solar with 44% on average. (Section 12.2.5)

Net Macroeconomic Analysis (Section 12.3)

- In the initial years (2022–2025) when Puerto Rico transitioned to a more reliable and stable electric system, aggregate job and real income losses due to electricity price increases outweighed the gains caused by new investments and expenditures. (Section 12.3.5)
- Between 2025 and 2045 as increasingly more renewable energy resources were added to this more reliable electric system, real electricity prices stabilized and sometimes declined, resulting in generally positive, but small, economic impacts. (Section 12.3.6)
- Simulated economic impacts on real household income varied substantially across regions, time, and scenarios, due in part to differences in the relative sizes of the regional economies. (Section 14.3.6)
- Low-income households (earning $15K/year or less) were especially vulnerable to large electricity price increases, which had implications for energy justice. (Section 12.3.6)

Considerations

- Efforts to reduce the utility's revenue requirement to mitigate retail rate growth will require more integrated and potentially longer-term planning efforts that consider all opportunities to reduce integration costs of increasingly greater levels of variable renewable generation resources.
- Redesigning retail rates to improve the temporal alignment between the types of costs incurred (i.e., sunk/fixed versus variable) and the types of charges employed to recover those costs (i.e., fixed versus variable) will be increasingly important to support the utility's financial health.
- Distributed PV compensation reform will be increasingly critical to mitigate revenue shifts to nonparticipants, address equity and energy justice concerns, and to support opportunities that reduce utility costs while capturing broader societal benefits related to renewable generation.
- The volatility in construction/installation jobs between now and 2030 and then again between 2040 and 2050 suggests a need to consider the right balance between job training efforts to create a local workforce that supports sustainable employment opportunities and outsourcing additional jobs to non-Puerto Rico entities. Restructuring the RPS could also help mitigate this volatility.
- The relatively stable growth in O&M jobs suggests there is more time available to develop effective and efficient job training programs to create a sustainable local workforce.
- Given the level of capital expenditure needed to support the transition to 100% renewable energy, policymakers looking to increase positive local economic impacts may want to identify potential opportunities for producing needed inputs in Puerto Rico.

12.1 Utility Retail Rate Analysis

This section documents the key findings, methods, assumptions, results, and interpretation of the utility retail rate analysis that was performed as one of the last steps in PR100. This analysis integrated the outputs from the following other PR100 analyses:

- Electric loads, energy efficiency savings, and electric vehicle charging load as discussed in Section 7
- Distributed PV production as discussed in Section 9
- Scenario definition and configuration as discussed in Section 8
- Capacity expansion, production cost, and resource adequacy as discussed in Section 10
- Bulk power grid reliability and resilience as discussed in Section 11
- Distribution grid impacts as discussed in Section 13.

This analysis was also influenced by stakeholder input. Section 3 describes how the PR100 project team gathered, documented, and incorporated that stakeholder input into scenario definitions and our collective analysis.

Key Findings

- Retail sales net of energy efficiency savings, electric vehicle adoption, and rooftop PV under net metering fell by 10%–55% between 2020 and 2050 and were overwhelmingly driven by distributed PV adoption.
- To achieve a more reliable and stable energy system, the utility experienced a substantial increase in its revenue requirement (48%–57%), between 2020 and 2025, resulting in large all-in average retail rate growth (66%–83%). The adequate generation fleet modeled met the 40% renewable portfolio standard.
- Between 2025 and 2045, the utility experienced a decline in its revenue requirement (9%–24%) driven by reductions in administrative costs (i.e., bankruptcy debt and pension repayment) and investments in less expensive generation resources that met interim RPS requirements. However, increasing levels of rooftop PV adoption caused retail sales to drop (-1% to -41%), resulting in all-in average retail rates that either dropped modestly (-8%) or increased substantially (34%).
- To fully achieve the 100% RPS requirement between 2045 and 2050, the utility experienced an increase in its revenue requirement (4%–16%), resulting in modest average retail rate growth (11%–17%).
- Increases in retail rates adversely affected the bills of nonadopters of rooftop PV, who for residential customers were more likely to be low-income, resulting in energy justice implications.
- The utility's revenue requirement was increasingly dominated by sunk or fixed costs that did not vary in the short term with changes in retail sales, whereas the utility's collected revenue could vary in the short term with changes in retail sales because utility rate design relied heavily on volumetric energy charges set during rate cases.

12.1.1 Introduction

The financial viability of a utility company lies at the core of its mission to deliver uninterrupted and efficient services to its customers. Revenue requirements serve as a fundamental metric in this context, encompassing the total annual cost necessary for a utility to meet its financial obligations, maintain operational functionality, and provide service to its customers. The revenue requirements are derived from an assessment of the utility's annual operating costs, including any income tax and a return both of and on capital expenditures. The resulting revenue requirement plays a central role in determining utility rates, providing a transparent and economically sound approach to pricing electricity and services for consumers.

Moving entirely to renewable forms of energy will affect the utility's operating, maintenance, and capital costs. Every residence and business in Puerto Rico that is directly connected to the electric grid will experience the financial implications of the transition to 100% renewable energy sources through their electric utility bill.

To better quantify the financial implications of this transition, the utility retail rate analysis in PR100 developed a pro forma financial model. This model builds up an estimate of the annual revenue requirement and annual retail sales of a combined PREPA, LUMA, and Genera PR LLC (Genera) utility (including any HoldCo, HydroCo, and PropertyCo costs)[151] in each year from 2020 through 2050[152] based on pathways to achieve a more stable and reliable electric system by 2025 as well as the Act 17-2019 RPS requirement developed in other PR100 modeling activities that retain the historical roles and responsibilities of the utility and its customers. The model employs cost-of-service rate-making principles that assume all incurred costs would be deemed prudent by regulators and thus warrant recovery in retail rates at levels that would ensure revenue sufficiency and sustain the utility's financial well-being. Our model complies with all currently applicable statutes and regulator decisions. It relies on public information regarding decisions on the use of federal recovery funds and the bankruptcy settlement negotiations for inputs. There is no behavioral response to changes in electricity prices over time (i.e., demand is inelastic; no grid defection) in the model. There is also no feedback between the outcomes from the pro forma financial model and other PR100 analysis efforts, with the exception of the net macroeconomic analysis which receives retail electric utility rate results as an input. Lastly, the model estimates average retail rates and average customer bills for two simplified subclasses of residential customers: general residential service (GRS) and lifeline residential service (LRS).

12.1.2 Methodology, Inputs, and Assumptions

12.1.2.1 Background on Utility Rate-Making

In Puerto Rico, the utility's revenue requirements consisted of O&M expenses along with debt service costs. O&M expenses constituted a significant portion of the revenue requirements, covering day-to-day costs associated with the running and upkeep of utility infrastructure as well as providing services to customers. These expenses encompassed costs such as employee salaries and pension expenses, maintenance costs, fuel and purchased power costs, administrative and

[151] For simplicity, the term "utility" will be used throughout this section without regard to which specific entity may be responsible for the identified activity or incur the identified cost. However, where appropriate, the specific utility entity will be explicitly identified.

[152] Because many of the inputs used in this retail rates analysis are presented in terms of fiscal years (July 1–June 30) instead of calendar years, the retail rates analysis is performed in fiscal years. However, to maintain consistency with results from the other tasks in PR100, the results are presented in the starting year of the fiscal year.

regulatory overheads, programs such as energy efficiency, contribution in lieu of income tax (CILT), and the procurement of necessary services, supplies, and materials.

In addition to operating expenses, Puerto Rico's revenue requirements also factored in debt service obligations associated with prior and future capital investments. Debt service included interest payments and principal repayments on the utility's outstanding debts. By including adequate debt service amounts in the revenue requirement, the utility can support its creditworthiness and access capital markets to fund future infrastructure upgrades and expansions.

In Puerto Rico, no income tax was assessed on the utility; therefore, income tax amounts were not included in the revenue requirement.

Because the revenue requirements represented the annual utility costs that must be collected, they played a pivotal role in the formulation of utility rates. Regulatory authorities, such as public utility commissions, relied on the analysis of these requirements to establish just and reasonable rates that balance the interests of both consumers and utility providers. The rate-setting process involved a comprehensive review of the utility's revenue requirements, cost structures, and demand.

Through careful consideration of the revenue requirements and corresponding cost elements, regulators can arrive at utility rates that adequately recover the utility's expenses and ensure debt service obligations can be met. Furthermore, rate design also considers broader policy objectives, such as encouraging energy conservation, promoting renewable energy adoption, and addressing affordability concerns for low-income consumers.

12.1.2.2 General Assumptions

The pro forma financial model created to analyze retail electric rates commenced in 2020, with a start date of July 1 and an end date of June 30 the following year to conform with fiscal years. Historical cost and usage data were provided for this year, creating a solid basis for comparing results for the six scenarios and variations analyzed. The PR100 analysis commenced in 2021 and relies on estimated future cost and usage data through 2050. In addition to achieving an adequate generation fleet by 2025 as well as the Act 17-2019 requirements, these projections account for forecast changes in energy demand, costs, technological advancements, U.S. federal income tax benefits, and other factors that may influence the power sector landscape over the next three decades.

One crucial milestone considered in the analysis was the PREPA bankruptcy exit, assumed to occur in 2024. This pivotal event triggered the commencement of various activities that significantly impacted the cost of electricity in Puerto Rico. These included Service Commencement under the LUMA and Genera contracts, the commencement of repayment of legacy indebtedness amounts, and legacy PayGo pension amounts.

The pro forma financial model estimated retail rate trajectories for four simplified customer classes: Residential, Commercial, Industrial, and Other (comprising Agricultural, Street Lighting, and Other Authorities). The Residential class was further divided into LRS and GRS subcategories for bill calculation purposes. This segmentation allowed for a more nuanced examination of the distinct needs and patterns within these customer classes and created an opportunity to assess energy justice issues associated with the transition to 100% renewable forms of energy.

12.1.2.3 New Infrastructure Capital Expenditures

The federal government has obligated roughly $21 billion to Puerto Rico since Hurricanes Maria and Irma devastated the Commonwealth. However, specific investments that would use that funding have yet been fully identified and approved. In addition, some of these federal funds are not applicable to the development of the utility's revenue requirement, as they do not represent costs the utility would typically incur. Specifically, DOE's Puerto Rico Energy Resilience Fund has $1 billion to financially support rooftop PV and storage installations and offer consumer protection and education resources. None of these represent typical utility costs, and so were excluded from our analysis.

Due to timing of our analysis and our interest in relying on a well-established, publicly accessible and thoroughly sourced reference for recovery-related investments which were eligible for accessing these federal funds, we do not perform our own analysis to determine the costs needed to bring the electric system back into a state of good repair, but rather rely on the Financial Oversight and Management Board's (FOMB's) 2023 Certified Fiscal Plan for PREPA (FOMB 2023b) to identify both the level of investment and the sources of funds to cover that level of investment. Accordingly, our analysis assumes a total utility investment of $15.441 billion, which includes generation, transmission and distribution system repairs and replacements,[153] as well as Tranche 1 transmission network upgrades. No other recovery-related investments are included in our analysis. Put differently, we do not include any additional recovery-related investments which required nonfederal sources of funds to cover. As such, these costs do not vary by PR100 scenario.

Since these recovery-related investments generally support repair or replacement of infrastructure damaged due to the hurricanes, our analysis assumes that insurance proceeds would be the first source of funds to pay for the portfolio of investments. Of the resulting net investment cost, the federal government requires a 10% cost share in order to gain access to Federal Emergency Management Agency (FEMA) funds, which would cover the other 90% of the investment. To help meet a portion of that required cost share, the U.S. Department of Housing and Urban Development authorized the use of their recovery-related funds. Our analysis assumed the remainder of the required cost share would be first met by funding provided by the Government of Puerto Rico, with the residual amount covered by the utility's ratepayers. Based on these assumptions, our analysis identified the following sources of funds to cover this $15.441 billion investment (Figure 311):

- $13.723 billion supplied by FEMA (FOMB 2023b)
- $0.500 billion supplied by HUD (FOMB 2023b)

[153] The 2023 Certified Fiscal Plan discusses that additional costs related to damages caused by Hurricane Fiona are estimated to total more than $4 billion and may be eligible for federal funding. However, because these estimates are preliminary and it is unclear which sources of funds will be used to cover them, we did not include these costs in our analysis.

- $0.285 billion dedicated by the Government of Puerto Rico from 2023 to 2025 (LUMA 2023b)
- $0.193 billion in insurance proceeds (FOMB 2023b)
- $0.740 billion collected from ratepayers through 2034, financed via headroom in rates from 2020 to 2028, at which point PREPA is assumed able to access capital markets after its exit from bankruptcy in 2024.

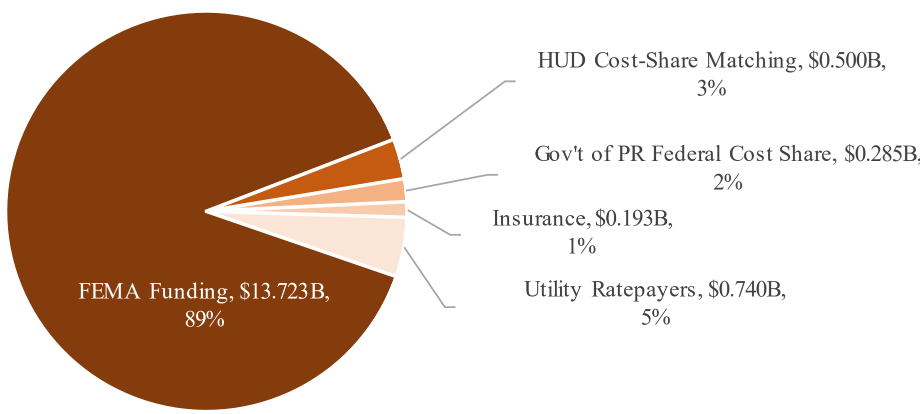

Figure 311. Funding sources, amounts ($ billions) and share of total (%) for infrastructure investments resulting from Hurricane Irma and Hurricane Maria

Beyond recovery-related investments, the utility also needed to make investments in the electric grid to meet the Act 17-2019 RPS requirements, as follows, all of which vary by PR100 scenario:

- **Transmission System Expansion:** Interconnection of new renewable generation resources to meet Act 17-2019 RPS goals is expected to require construction of new tie lines to the bulk power system in Puerto Rico. The entities assumed to be responsible for covering the costs of these transmission network upgrades vary over time. The Tranche 1 transmission network upgrade costs estimated at $100 million were eligible for federal cost recovery, resulting in the utility's ratepayers bearing a fraction of the 10% cost share, as discussed above. For subsequent tranches, transmission costs[154] were assumed to be financed by third-party renewable generation development sponsors and thus included in power purchase and operating agreement (PPOA) costs until 2028 when PREPA was assumed to be in a position to finance these investments due to its exit from bankruptcy and ability to access capital markets (see Section 12.1.2.4 for details). Total utility-incurred capital expenditures for transmission system upgrades over the analysis period are shown in Figure 312 and varied by scenario.

[154] Estimated as renewable generation installed capacity (kW) times $85/kW Tranche 2 sponsor cost cap, without any assumed cost escalation over time (Accion Group 2022).

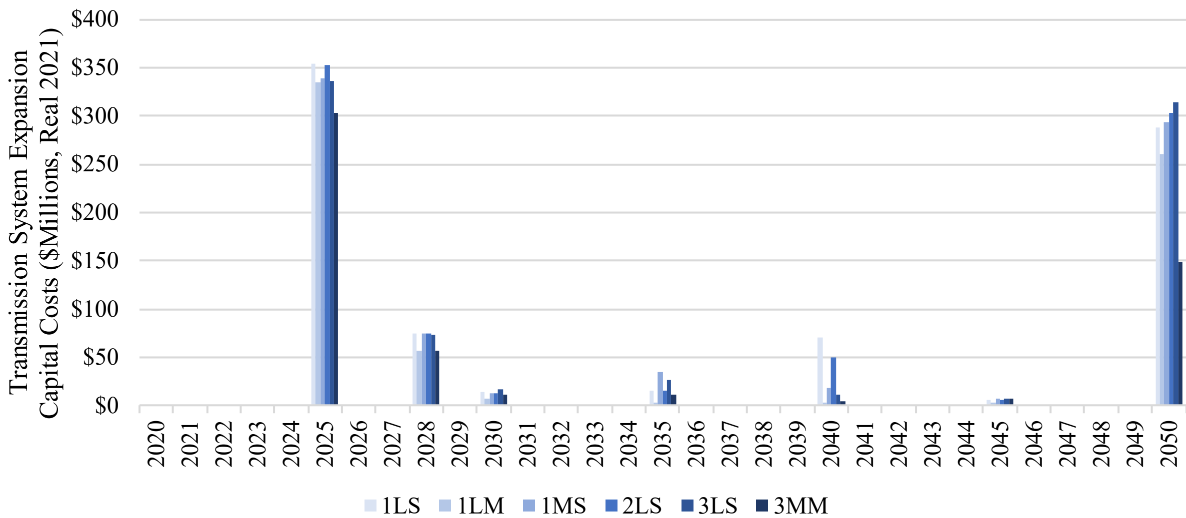

Figure 312. Transmission system expansion costs

- **Distribution System Upgrades:** To support the expanded use of distributed energy resources (DERs) and electric vehicles (EVs), which are assumed to be entirely interconnected to the distribution system, the utility will need to upgrade parts of the distribution system. The analysis described in Section 12.3.5.3 identified the excess capacity (MW) and energy (MWh) that cannot be integrated on the distribution system without additional investments. We assumed storage would be installed to mitigate these integration challenges on the distribution system. For each scenario, in years when distribution system storage needs to mitigate integration challenges exceeded bulk power system storage procurements identified in the capacity expansion analysis discussed in 8.4.2 (page 225), the pro forma model added incremental storage. This incremental storage was assumed to be procured via PPOAs per storage costs described in Section 8.2.6.1 (page 218) (Figure 313).

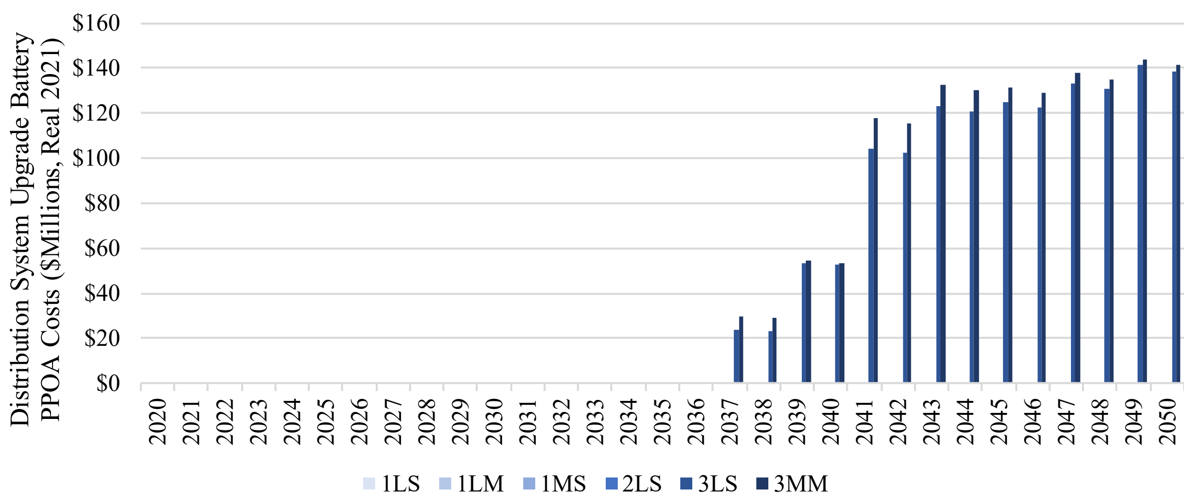

Figure 313. Distribution system upgrade battery PPOA costs

12.1.2.4 Legacy Bankruptcy and Pension Repayment

As previously stated, PREPA is currently in bankruptcy. We assumed repayment obligations of previously incurred debt were consistent with the terms and conditions laid out in the Modified Informative Motion of the Financial Oversight and Management Board for Puerto Rico Listing Primary Amendments to Title III Plan of Adjustment in Connection with Certification of 2023 PREPA Fiscal Plan dated June 23, 2023 (FOMB 2023c).[155] We assumed legacy debt amounts of roughly $2.4 billion were repaid via the proposed legacy charges structured as fixed monthly connection fees and volumetric energy charges ($/kWh) and that these amounts were applied until the entire repayment obligation has been met. Lastly, we assumed repayment commences in 2024, when PREPA was assumed to emerge from bankruptcy and will have made the necessary billing and accounting system upgrades necessary to implement these legacy charges. The revenue collected through the application of these charges will depend on the level of retail sales. Accordingly, annual collected revenue from these charges and the duration of application to ratepayers varied by PR100 scenario (Figure 314).

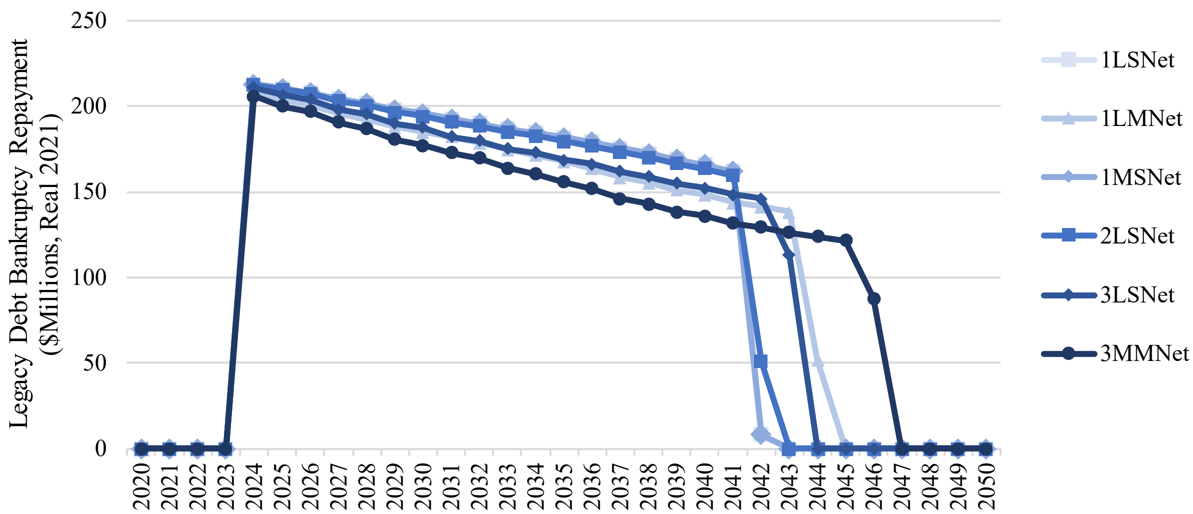

Figure 314. Legacy debt repayment costs

PREPA also had legacy pension obligations that must begin to be repaid upon emerging from bankruptcy. These PayGo annual pension obligations ($/yr) through 2039 were based on values identified in the FOMB 2023 Fiscal Plan and thereafter were assumed to be equal to the 2039 value in real terms (Figure 315). To collect these costs in rates, we derived a volumetric energy charge ($/kWh) rate rider that perfectly collected these annual legacy pension obligations based on retail sales levels by class, excluding Tier-1 residential fixed rate (RFR) usage, which varied by PR100 scenario.

[155] A third amended plan was released by FOMB in late August 2023 that was subsequently modified in October 2023 but was too late for us to integrate into our analysis.

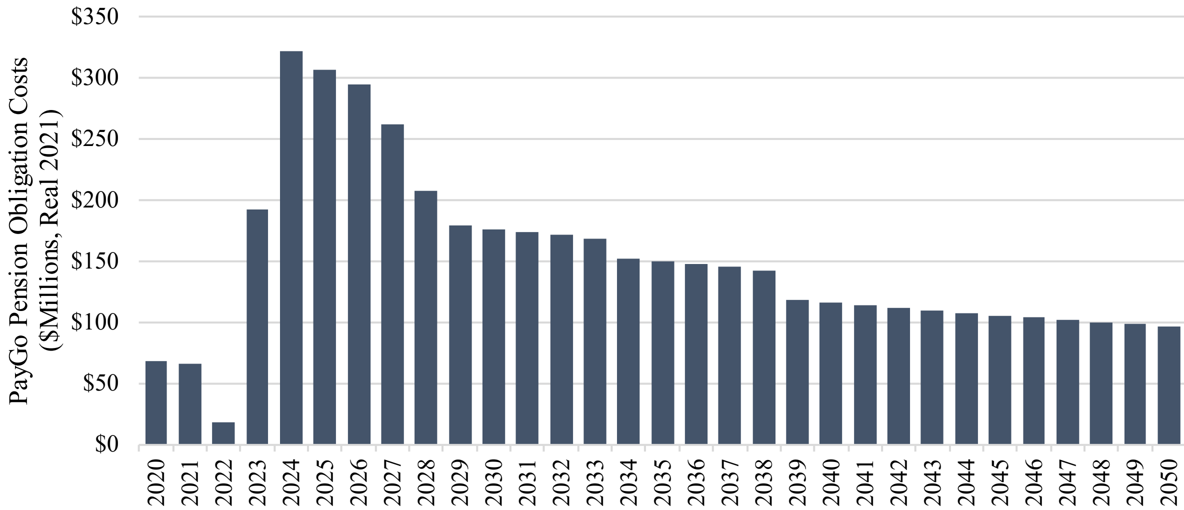

Figure 315. PayGo pension obligation costs

Although we assumed PREPA would emerge from bankruptcy and begin assessing its negotiated legacy obligations starting in 2024, we assumed it would take another 4 years (2028) before capital markets were again readily available to PREPA. To estimate the future finance terms under which PREPA may finance investments starting in 2028, we employed data from the Puerto Rico Aqueducts and Sewers Authority. It refinanced $1.4 billion of long-term senior debt in December 2020 at 4%–5% interest rates for repayment by July 2047 (Acueductospr 2023). In August 2021, it refinanced another $0.9 billion of long-term senior debt at identical interest rates with the bonds coming due in July 2042 or July 2047 (Acueductospr 2023). Based on these data, we made the following finance assumptions for future PREPA debt, none of which varied by PR100 scenario:

- Base debt cost in FY21 = 5%
- Debt cost over time adjusted according to the FOMB inflation trajectory
- A 40-yr finance term (to directionally reflect the economic life of the assets financed).

Based on these financial assumptions, the debt service costs incurred by PREPA on invested capital commenced in 2028 and varied by scenario (Figure 316).

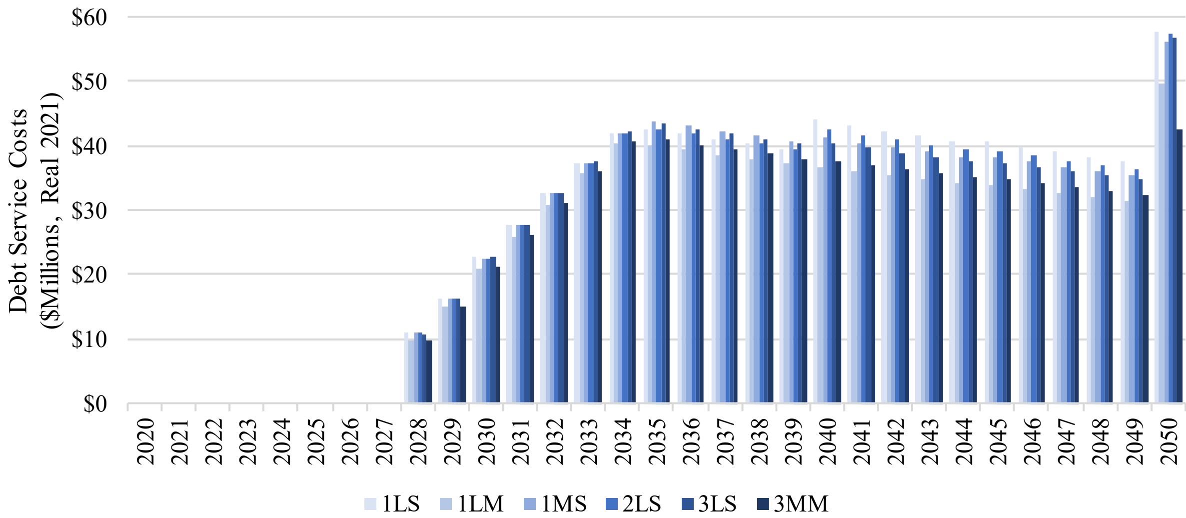

Figure 316. PREPA debt service costs

12.1.2.5 LUMA Contract Fees and Fixed O&M Costs

LUMA took over responsibility from PREPA in 2021 for operating and maintaining the transmission and distribution systems and was assumed to play that role through the end of the analysis period. The payments, fees, and incentives owed to LUMA were described in their support contract. In 2021, LUMA received an up-front payment to cover startup expenses. During the interim period before PREPA emerges from bankruptcy (assumed to be 2024), LUMA receives service fees and incentive payments. PREPA's emergence from bankruptcy triggers Service Commencement under this contract. The assumed annual schedule of contract fees for LUMA is shown in Figure 317.

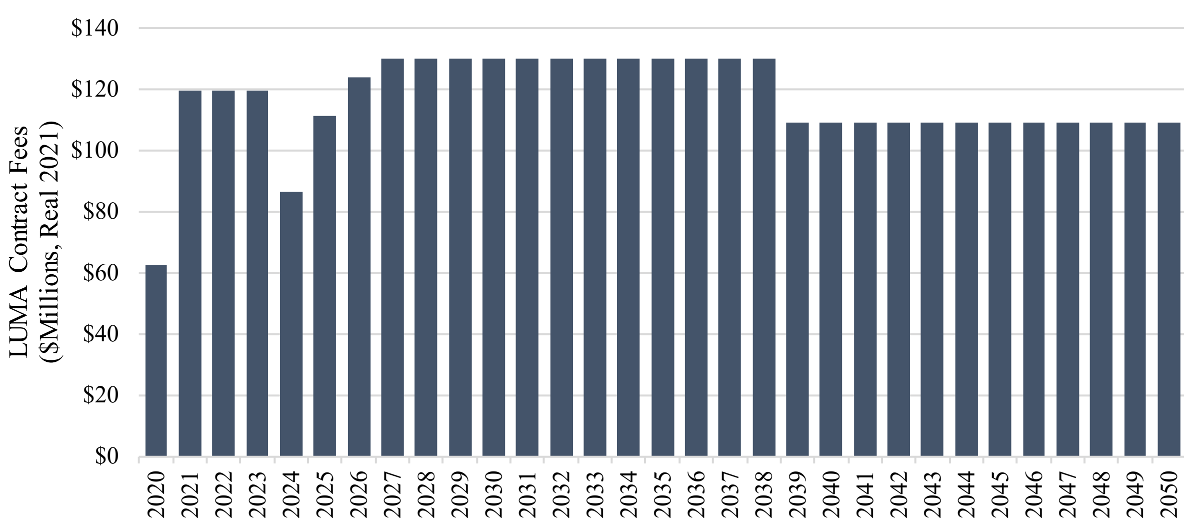

Figure 317. LUMA contract fee schedule

In addition to these fees, LUMA incurs costs to operate and maintain the distribution and transmission systems. Developing a cost forecast for LUMA's fixed O&M responsibilities through FY51 was complicated by several near-term and long-term factors. In 2017, its predecessor (PREPA) entered bankruptcy and since then has had very limited financial ability to perform routine O&M activities. That same year, Hurricanes Irma and Maria hit, devastating the Commonwealth's electric system infrastructure. As a result, O&M efforts have focused on rebuilding efforts, which are expected to differ substantially from activities undertaken in a more steady-state grid in the future.

To derive cost estimates for this new era of the steady-state utility, we sought data for a comparable utility that could help inform O&M costs and act as an appropriate proxy. Hawaiian Electric Company (HECO) is a U.S. electric utility for an island archipelago that is likewise transitioning to 100% renewable energy and is required to file detailed incurred cost reports that are publicly accessible. We used cost data contained in HECO's 2021 annual utility reports to the Hawaii Public Utility Commission to estimate 2019 unit fixed O&M costs by cost type (Table 43) and then escalated these values per FOMB's inflation trajectory and multiplied these adjusted unit costs by the appropriate units to derive annual estimates of fixed O&M budgets (Hawaii PUC 2021).

Table 43. Estimated HECO-Based Per-Unit Fixed O&M Cost

Data Source: Hawaii PUC (2021)

Cost Type	HECO Unit Cost (2019$)
Transmission O&M: existing	$47,312 per line mile
Transmission O&M: new	$0.009 per $ million CapEx
Distribution O&M: existing	$14,217 per line mile
Substation O&M (D): existing	$0.020 million per substation
Substation O&M (Tx): existing	$0.140 million per substation
Customer	$127 per customer
Load	$0.74 per MWh of load
A&G (e.g., legal and regulatory)	$132 million fixed annual

However, the Puerto Rico utility's transition to a steady-state electric system was not expected to occur overnight. To reflect this in the pro forma model, initial O&M costs assumed near-term fixed O&M budget estimates based entirely on publicly available data from LUMA (LUMA 2023b) through 2025. These were then escalated at FOMB's assumed inflation rate through 2050. We phased in linearly the FOMB inflation-adjusted HECO-based fixed O&M budget estimates with the inflation-adjusted LUMA cost figures over a 10-yr period starting in 2028, the year PREPA was assumed to exit bankruptcy. Once the steady state had been achieved starting in 2038, we relied exclusively on an average of the HECO-based and inflation-adjusted LUMA-based fixed O&M budget estimates. The results are shown in Figure 318.

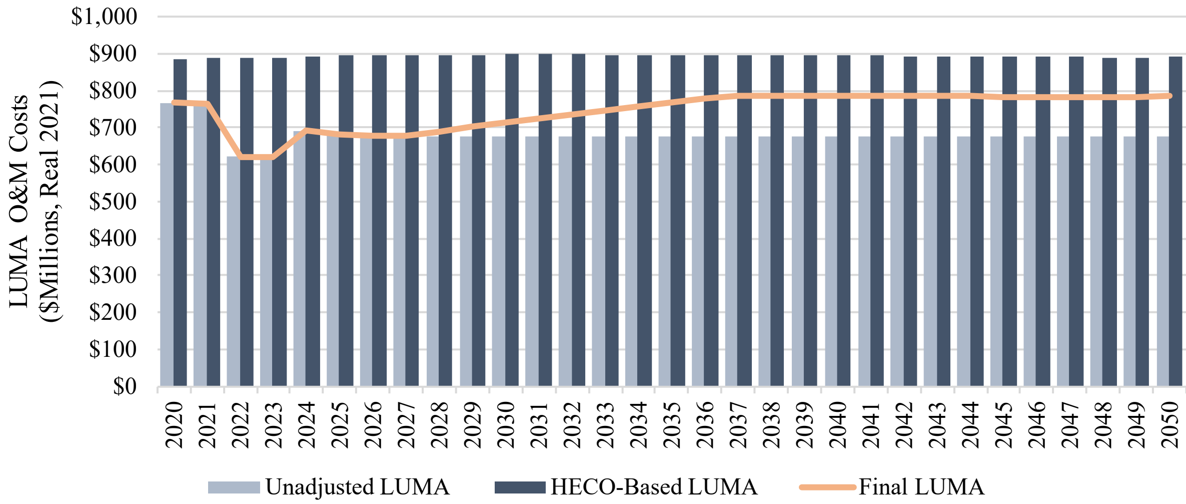

Figure 318. LUMA fixed O&M costs

It is worth noting that HUD- and FEMA-funded hurricane-related infrastructure investments were not assumed to impact the utility's fixed O&M budgets. However, new expenditures on the transmission system did impact these budgets. The resulting LUMA fixed O&M cost trajectories therefore vary across PR100 scenarios (Figure 318) but not materially.

12.1.2.6 Generation Costs

As described more in Section 8.4.2.1 (page 229), Puerto Rico presently has a fragile electric system, due to the current portfolio of generating assets, that is susceptible to frequent outages and lacks resilience to a number of exogenous threats (e.g., hurricanes). The PR100 analysis assumes significant generation and storage investments are made in the early years through 2025 to create a more reliable electric system that also complies with the 40% RPS requirement in Act 17-2019. Between 2025 and 2045, the PR100 analysis models continued investments in renewable forms of electric generation resources and storage technologies to meet interim Act 17-2019 RPS requirements while maintaining a reliable electric system. During the last five years of the analysis horizon, the PR100 analysis models a final set of utility-scale resources which fully meet the Act 17-2019 100% RPS requirement and continue to achieve reliability requirements.

In Puerto Rico, the electric grids capacity, energy, and ancillary service needs are met by a combination of utility-owned generating assets and third-party-owned resources procured through PPOA contracts. Costs associated with each type of electricity generating facilities are discussed in this section.

The utility-owned generating facilities include both fossil fuel and hydroelectric plants. In 2023, Genera assumed responsibility from PREPA for operating and maintaining the existing (i.e., legacy) generating facilities interconnected to the bulk power system. The payments, fees, and incentives were all laid out in their support contract, which has an initial term of 10 years (PREPA, Puerto Rico Public-Private Partnerships Authority, and Genera PR 2023). We assumed the contract was extended until the legacy generation units retire in FY51, with the costs of the Genera contract assumed to decline pro rata with legacy generation retirements (see Contract Fee in Figure 319). Although PREB envisions granting responsibility for operating and maintaining PREPA's hydroelectric facilities to a third party (i.e., HydroCo), this transfer has not yet occurred. Accordingly, we developed estimates for the necessary maintenance expenses as well as labor, nonlabor, and shared expenses associated with activities not directly related to all of the utility-owned generating facilities based on recent historical data (LUMA 2023b) but adjusted going forward to reflect facility retirements (see Nonfuel Fixed O&M in Figure 319). Lastly, these utility-owned generating facilities incur O&M costs whether these power plants are generating electricity. These fixed O&M costs are described in Section 8.2.6.1 (page 218) and used as an input to our model (see Legacy Gen Fixed O&M in Figure 319).

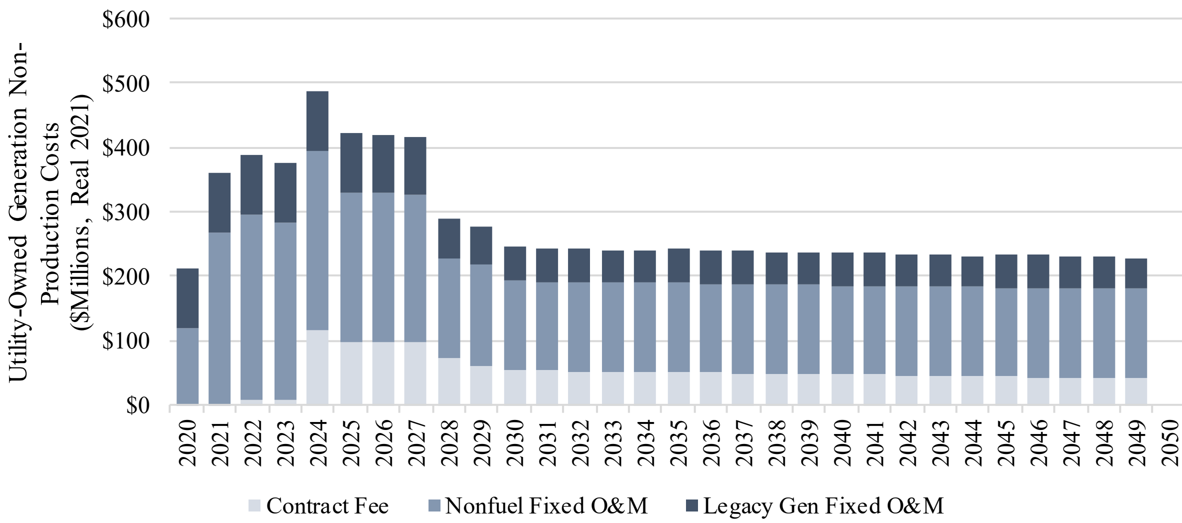

Figure 319. Utility-owned generation non-production costs

The utility-owned generating facilities incur costs to produce electricity, which consist of startup costs, fuel costs (including biofuel starting in 2050), net storage dispatch revenues, and variable O&M costs. These production costs were derived as part of the analytical results described in Section 5.2.5 and vary by PR100 scenario (Figure 320).[156]

[156] Technically, the fuel costs derived from the analytical results described in Section 11.3 included nonutility-owned biofuel costs and nonutility-owned battery storage profits. Unfortunately, we were unable to break those costs out separately and remove them to derive a clean estimate of the utility-owned generation production costs. Therefore, for simplicity, we opted to simply identify these fuel costs as utility-owned production costs but recognize they did include these additional nonutility production costs.

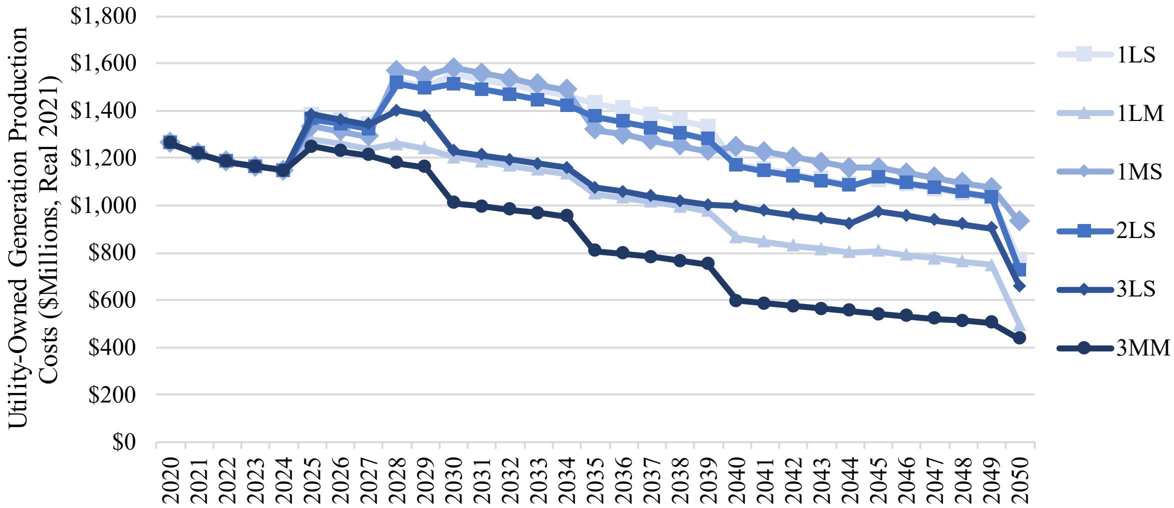

Figure 320. Utility-owned generation production costs

New renewable generation as well as storage resources to meet near-term reliability improvements as well as Act 17-2019 RPS requirements over the entirety of the analysis time horizon are expected to be procured via PPOAs. Because the current installed capacity of renewable resources in the Commonwealth is very small,[157] private nonutility entities will need to install a considerable number of renewable resources, which will vary by scenario. The analysis described in Section 8.2.6.1 (page 218) developed cost projections for all future third-party-owned renewable generation and storage procurement, excluding dispatchable renewable fuel costs (e.g., biofuel). In the pro forma model, these PPOA costs include sponsor-borne transmission network upgrade costs, which were developed as part of this analysis and added to the PPOA costs developed as part of the analysis described in Section 8.2.6.1.8 (page 222). As noted in Section 12.1.2.3 (page 407), the Tranche 1 transmission network upgrade costs were assumed to be funded by FEMA. Beyond Tranche 1, transmission network upgrade costs were assumed to be funded by the third-party sponsor via its PPOAs until 2028 when PREPA was assumed to be in a position to finance these costs. Figure 321 presents the utility-incurred generation-related costs from third-party PPOAs by scenario, including the costs of any sponsor-financed transmission network upgrade costs required to integrate bulk grid-connected renewable generation.

[157] Regarding third-party-owned utility-scale generating facilities in Puerto Rico, legacy resources are a mix of fossil generation and renewables.

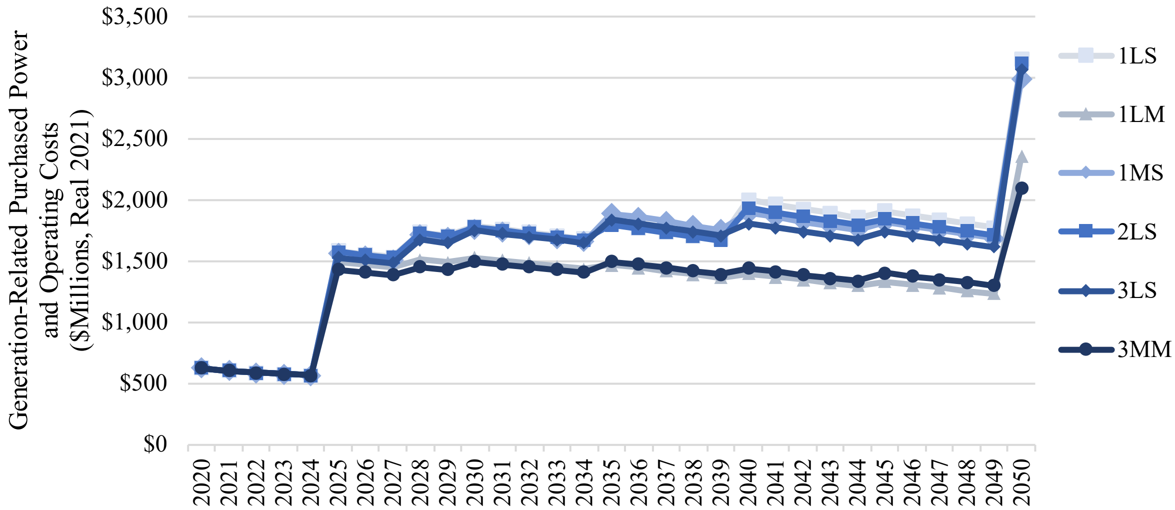

Figure 321. Generation-related purchased power and operating costs

12.1.2.7 Holding Company Costs

PREB has also expressed an interest in contracting with outside entities for the operations, maintenance, and management of property assets via a PropertyCo, for the O&M of the utility's hydroelectric generation via a HydroCo, and for remaining nonoperational functions via a holding company (HoldCo). As previously noted, the pro forma model included HydroCo costs within the generation costs depicted in Figure 321. No PropertyCo-specific cost estimates were discussed in the FOMB 2023 Fiscal Plan. Estimates for HoldCo costs were developed and are shown in Figure 323 (FOMB 2023b).

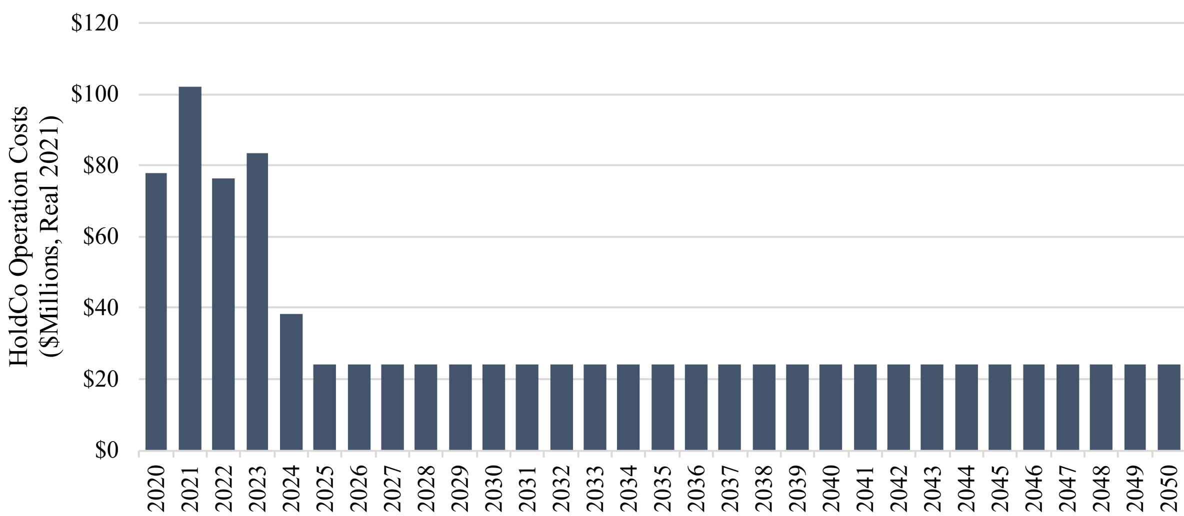

Figure 322. Holdco operating costs

12.1.2.8 Contribution in Lieu of Taxes and Other Subsidies

Municipal and local governments are ratepayers of the utility in Puerto Rico. However, the Contribution or Payment in Lieu of Taxes (CILT) is the mechanism, established by PREPA's Organic Act, by which the utility compensates municipalities with power in exchange for municipal tax exemption (PREB n.d.).

Subsidies to other utility ratepayers in Puerto Rico are required of PREPA by PREB, according to its tariff book (PREPA 2019).

The Help to Humans (PREPA tariff designation SUBA-I) subsidy comprises the following:

- Credit for Consumption of Electrical Equipment Necessary to Preserve Life
- Residential Service for Public Housing Projects Rates—RH3
- Lifeline Residential Service (LRS)
- RFR for Public Housing under Ownership of the Public Housing Administration
- Residential Fuel Subsidy
- Public Lighting (Municipal)
- PREB Assessment.

The Non-Help to Humans (PREPA tariff designation SUBA-NHH) subsidy comprises the following:

- Analog Rate to the Residential to Churches and Social Welfare Organizations
- General Agricultural Service (GAS)
- Credit for Incentives to the Tourism Sector (Hotel Discount)
- Residential Rate for Communal or Rural Aqueducts
- Credit to Small Merchants in Urban Centers (Downtown 10% Subsidy)
- Residential Rate to Common Areas of Residential Condominiums
- Act 73-2008 Industrial Tax Credit
- Irrigation District.

Combined estimates of CILT and subsidies were developed and are shown in Figure 324 (FOMB 2023b).

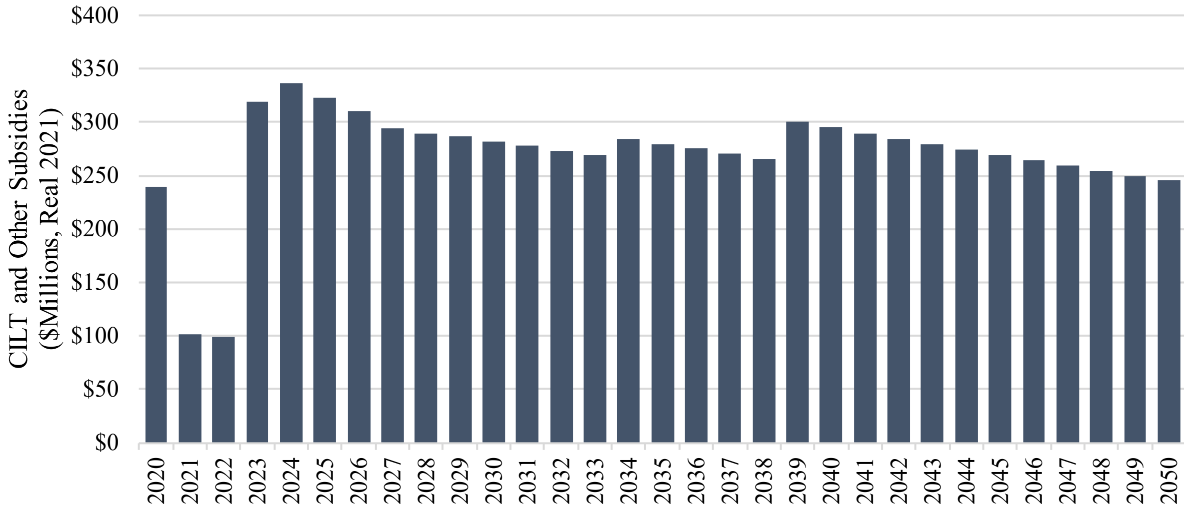

Figure 323. CILT and other subsidies

12.1.2.9 Bad Debt

For the annual revenue requirement to be perfectly collected, bad debt amounts must be recovered. Therefore, a provision for bad debt was added to the annual revenue requirement. Annual bad debt was assumed to be 1.5% of the total revenue requirement excluding bad debt (LUMA 2023b).

12.1.2.10 Energy Efficiency Program Costs

Act 17-2019 as well as recent regulations (i.e., NEPR-MI-2022-0001 Order dated April 3, 2023) set ambitious targets for savings from the installation of energy efficiency measures. The analysis discussed in Section 5.2 (page 124) developed estimates for the energy (kWh) savings associated with these measures over time: a top-down approach that meets the Act 17-2019 energy efficiency requirements. The analysis discussed in that same section also provided an estimate of the program administration costs required to achieve these savings levels (Figure 325).

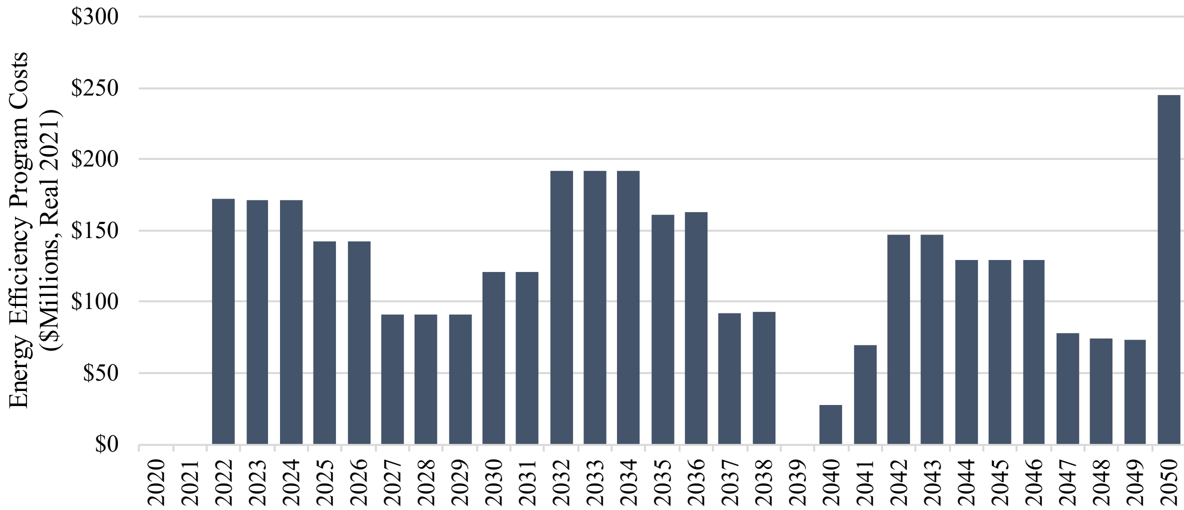

Figure 324. Energy efficiency program costs

12.1.2.11 Billing Determinants

Two types of billing determinants were used to calculate electricity rates in the pro forma model: retail sales and the number of customers. Distributed solar PV systems are assumed to interconnect to the system under a net energy metering export compensation regime. Therefore, retail sales billing determinants are calculated by subtracting the electricity produced by these distributed solar PV systems from the gross retail sales net of energy efficiency savings and EV charging that was reported in Sections 7.4 (page 199), 5.1 (page 119), 5.2 (page 124), and 5.3 (page 138), respectively.

12.1.2.11.1 Distributed Energy Export Compensation

According to Act 17-2019, the current method for compensating customers who have lawfully interconnected their solar PV systems to the electric grid is net energy metering. Under this compensation scheme, a customer is allowed to consume any electricity produced by their solar PV system rather than withdraw electricity from the electric grid through the utility meter. If any electricity produced by the customer's solar PV system remains unconsumed, it is injected (or exported) onto the electric grid through utility meter (effectively turning the meter backward). Each month, the meter is read to determine if more electricity was injected onto the grid than was withdrawn from the grid. If such is the case, energy (kWh) credits accrue that can be applied in subsequent months when more electricity is withdrawn than injected, subject to some restrictions.[158] Each June, if any energy credits remain from the prior 12-month period, the utility issues a financial credit to the customer where 75% of the energy credits are valued at the higher of 10 ¢/kWh or total ¢/kWh minus fuel and purchased power charges (PREPA 2019).

In this analysis, under net energy metering, we assumed the total annual electricity produced by distributed solar PV systems never results in excess energy credits at the end of the 12-month period. Thus, we simply deducted all electricity produced by distributed solar PV systems from

[158] Energy credits are limited to a daily maximum of 300 kWh for residential customers and 10 MWh for commercial customers (DSIRE 2023).

the total forecasted electric load, without regard for whether the electricity was self-consumed or exported to the grid.[159]

Act 17-2019 also states that net energy metering will be the compensation scheme through spring 2024, at which point PREB shall release a report describing its study of benefits and costs of the net metering program, distributed generation technologies, and storage technologies, among other items. Once that report is filed, PREB has the discretion to alter the export compensation scheme.

12.1.2.11.2 Retail Sales

Forecasted load, energy efficiency savings, EV charging, and distributed PV production trajectories were developed as part of the analysis discussed in Section 7. This analysis multiplied distributed PV production trajectories provided in kWh_{dc} by an inverter loading ratio of 1.3 to convert these values to kWh_{ac}. Distributed PV kWh_{ac} were then subtracted from the load forecast net of energy efficiency and EV to produce the final retail sales trajectory displayed in Figure 326.

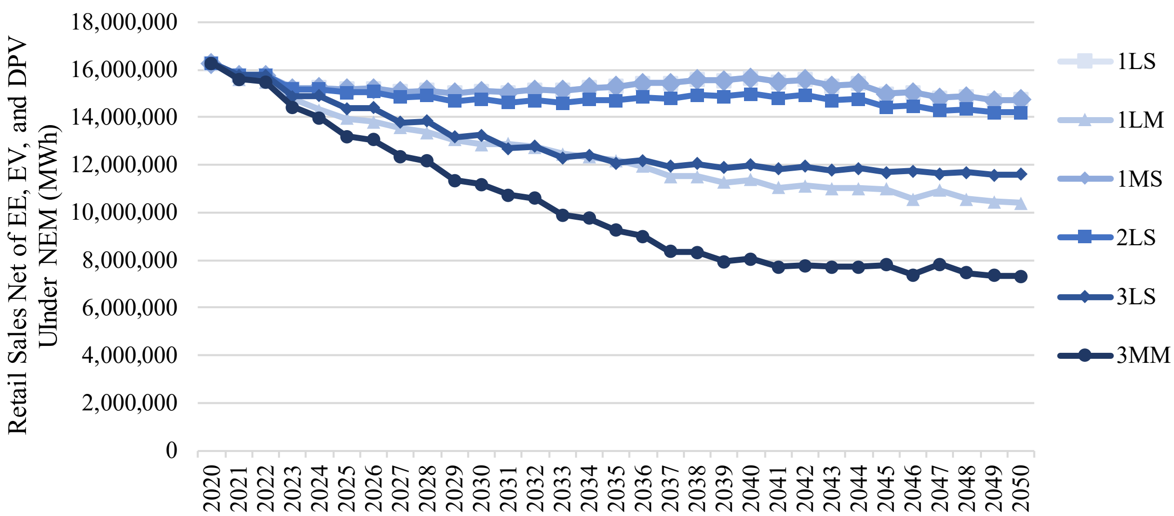

Figure 325. Retail sales: Forecasted load net of energy efficiency, EV, and distributed PV

12.1.2.11.3 Retail Customers

The number of customers in the residential, commercial, and industrial classes was estimated as part of this analysis based on historical relationships between population and the number of class-level customers.[160] No historical data were available for the simplified "Other" class; therefore, the number of customers in this class was not assumed to change over time. The trajectory of the number of customers is displayed in Figure 327.

[159] Had we instead assumed some level of excess energy credits at the end of each year, they would have shown up in the revenue requirement as an additional cost to be borne by all ratepayers.

[160] Although population figures in Puerto Rico are generally trending down, the ratio of the number of customers to population has been generally trending up. For example, LUMA's official historical data shows residential and commercial customer numbers growing from 2020 to 2021 and again from 2021 to 2022 (LUMA n.d.).

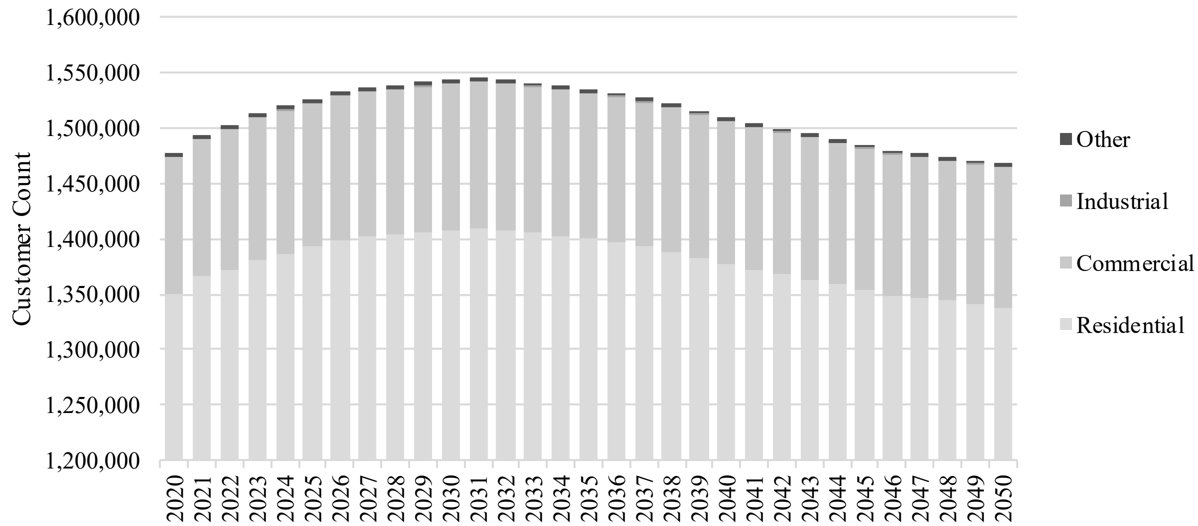

Figure 326. Customer counts by rate class

12.1.2.12 Cost Allocation and Rate Setting

With the annual revenue requirement of the electric utility characterized, the last two steps in the analysis were to allocate that revenue requirement to each of the four simplified customer classes (residential, commercial, industrial, and other) and to calculate rates. The rates calculated in our study assumed the total revenue requirement was perfectly collected in each year.

This allowed us to, first and foremost, estimate an all-in average retail rate, which was defined as the total revenue requirement divided by the total retail sales in each year of the analysis. For decades, the electric utility industry has used this metric to readily and simply represent the average cost of electricity to all utility ratepayers.

Because individual customers' bills are based not on the average all-in retail rate but instead class-specific rates, we also sought to develop simplified class-specific rates. PREPA, like many utilities, recovers some costs via basic tariff charges (i.e., monthly customer charge, energy charge) set during infrequent general rate cases and other costs via rate riders that are updated on a more frequent basis and, importantly, are balancing accounts that fully collect underlying costs. Typically, basic tariff charges differ by customer class while rate riders can be, and often are, universally applied to all customer classes. The process to develop class-specific rates for our study is described here.

Table 44 lists each of the specific revenue requirement cost elements discussed in Sections 12.1.2.1 (page 405) and 12.1.2.10 (page 419) and the type of charge that is assumed to recover each cost from customers.

Table 44. Revenue Collection Method for Revenue Requirement Elements

Revenue Requirement Element	Basic Charge	Rate Rider
Fuel costs		●
Purchased power costs (PPOAs)		●
Transmission network upgrades (PPOAs and PREPA-funded)	●	●
Distribution system upgrades (PPOAs)		●
Bankruptcy (legacy debt charges)		●
PayGo pension		●
LUMA contract fees	●	
LUMA fixed O&M costs	●	
Genera contract fees	●	
Genera and legacy generation fixed O&M costs	●	
Holdco, PropertyCo, and HydroCo contract fees	●	
CILT and subsidies		●
Energy efficiency programs		●
New capital expenditures	●	
Bad debt	●	

The method for allocating costs and establishing rates differentiated by basic charges versus rate riders is detailed in the next two sections.

12.1.2.12.1 Allocation of Costs for Estimation of Basic Tariff Charges

Once the costs to be collected via basic tariff charges were identified, we developed a method for allocating these costs to specific customer classes and to the basic charge tariff components within each class. Because this methodology will be developed in future utility rate cases and is therefore not currently known to us, we developed a simplified process for this cost allocation that preserves the current basic charge cost allocation relationships. This was accomplished through a four-step process.

In Step 1, basic tariff charge customer ($/month) and volumetric ($/kWh) rates were developed for each simplified customer class (residential, commercial, industrial, other) based on actual 2020 revenues. Extant customer charges were first multiplied by the 2020 number of customers in each class. This step produced an estimate of 2020 customer charge revenue. For residential customers, this calculation was performed separately for GRS customers and for all low-income customers grouped together. Class-specific 2020 customer charge revenue was then subtracted from class-specific 2020 basic tariff charge revenue. This step produced an estimate of 2020 volumetric charge revenue for each simplified customer class. Volumetric charge revenue for each class was then divided by 2020 retail sales (kWh) for each class. This step produced the average $/kWh volumetric basic tariff charge for each class modeled. This volumetric basic tariff charge estimation methodology was used because (1) demand billing determinants for commercial and industrial rate classes were not developed in PR100 and (2) 2020 data for Tier-1 and Tier-2 consumption for residential customers were not available.

In Step 2, initial basic tariff charge revenues for future years were estimated. This was accomplished by multiplying the annual class-specific basic tariff charge customer and volumetric rate components developed in Step 1 by the projections of annual customer numbers and annual retail sales for each simplified customer class. Note that in Step 2, these initial basic tariff charge revenues were not yet calibrated to the pro forma, basic tariff charge annual revenue requirements per the inputs discussed in Sections 12.1.2.1 and 12.1.2.10.

Step 3 calculated the shortfall or surplus needed to reconcile the initial annual basic tariff charge revenues developed in Step 2 to the pro forma basic tariff charge revenue requirement in each year. This step was accomplished as follows. For each year, the total revenue calculated in Step 2 was subtracted from the total annual basic tariff charge revenue requirement. For a given year, if the result was positive, the result produced was the basic charge shortfall. In this case, the initial basic charge revenues were not sufficient to collect the basic tariff charge revenue requirement, and the initial basic tariff charge revenues produced in Step 2 must be increased by the basic charge shortfall. If the result was negative, the result produced was the basic tariff charge surplus. In this case, the initial basic tariff charge revenues over-collected the basic tariff charge revenue requirement, and the initial basic charge revenues produced in Step 2 must be decreased by the basic charge surplus.

In Step 4, each annual basic tariff charge shortfall or surplus was allocated to customer classes pro rata with the class-specific customer and volumetric initial basic tariff charge revenue allocation developed in Step 2. For each class, when the allocated basic tariff charge shortfall or surplus amounts developed in Step 3 were added to corresponding initial basic tariff charge revenue components developed in Step 2, the class-specific basic tariff charge revenue—by customer and volumetric component—was perfectly collected. Step 4 therefore completed the allocation of basic tariff charge revenue requirements by simplified customer class, broken out by customer and volumetric components.

12.1.2.12.2 Rate Setting for Basic Charges

For each of the simplified customer classes, all-in average $/kWh rate results were calculated for each year and class. This was accomplished for each class by dividing the sum of class-specific customer and volumetric basic charge revenue requirements developed in Step 4 by class-specific retail sales.

Basic charge rate component trajectories for GRS and LRS residential customers were needed to calculate customer bills both before and after adoption of distributed PV plus a battery energy storage system (BESS). Generally, this was accomplished by applying basic charge customer and volumetric charge escalation rates to the extant GRS and LRS basic charge rate components. To calculate the low-income customer charge rate trajectory, the annual low-income customer charge revenue requirement developed in Step 4 was divided by the projected annual number of low-income residential customers. The low-income customer charge escalation rate in year n was calculated as the:

> Low-Income Charge = [low-income customer charge in year n ÷ low-income customer charge in year n-1] minus 1.

This escalation rate trajectory was applied to the extant LRS customer charge. A similar calculation was performed for GRS customers.

To calculate the annual residential volumetric basic charge rate escalation, the residential volumetric basic charge revenue requirement developed in Step 4 was divided by annual residential retail sales. The residential volumetric charge escalation rate in year n was calculated as

> Residential volumetric energy charge = [residential volumetric rate in year n ÷ residential volumetric rate in year n-1] minus 1.

To estimate GRS and LRS basic charge rates, these escalation rates were applied to the extant residential GRS and LRS volumetric basic charge rate components. This methodology preserved the ratio of Tier-2 to Tier-1 basic charge volumetric rates over time.

12.1.2.12.3 Cost Allocation and Rate Setting for Rate Riders

Costs that are collected via rate riders were assumed to be contemporaneously and perfectly collected using a volumetric energy charge ($/kWh). For all rate riders except the legacy bankruptcy repayment amounts, rate riders were assumed to be universally applied to retail sales from all rate classes, except for retail sales associated with the lowest consumption tier in the RFR class. To derive the annual rate rider rates ($/kWh) for all costs except for legacy bankruptcy repayment amounts, the annual utility cost ($) to be collected via each rate rider was divided by total annual retail sales less those associated with the lowest tier in the RFR class (kWh). For a given rate rider, the cost allocation was produced when the rate rider was multiplied by class retail sales (net of the lowest-tier RFR usage for residential customers). As a result, these costs were nearly perfectly allocated to each customer class based on a pro rata share of retail sales. Legacy bankruptcy repayment amounts were modeled by customer class per the proposed (FOMB 2023c) connection fee and volumetric rates, as described in Section 12.1.2.4.

12.1.3 Results

12.1.3.1 Utility Revenue Requirement

In 2020, the utility collected revenue of $3.2 billion (Figure 328). Our analysis showed a rapid and substantial increase in utility-incurred costs in the first 5 years of the analysis ending at a level between $5.0 billion and $5.3 billion. Between 2025 and 2045, the revenue requirement generally trended downward, shrinking to $3.9 billion–$4.7 billion. However, by 2050, substantial costs were incurred dramatically increasing the revenue requirement to $4.3-$5.4 billion.

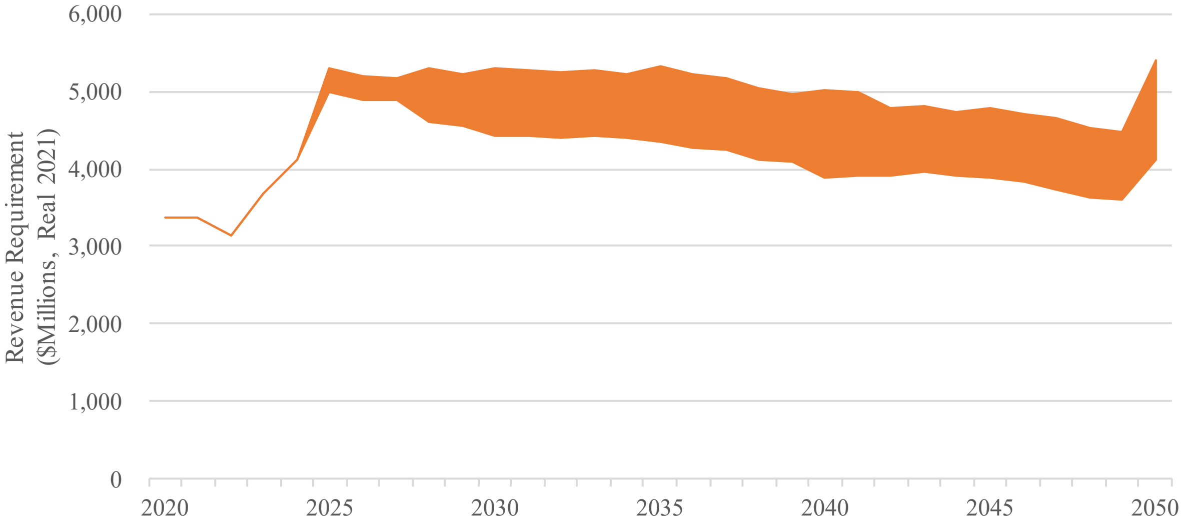

Figure 327. Total revenue requirement

By dividing the total revenue requirement into broad categories of its component elements, it was possible to identify specific drivers of these increases over time (Figure 329, Figure 330, and Figure 331). These broad categories were defined as follows:

- **Renewable Energy Generation**: Purchased power costs inclusive of reliability investments, transmission expansion and FEMA/HUD cost-share debt service costs[161]
- **Thermal Energy Generation**: Utility-owned generation fixed O&M, nonfuel O&M, and production costs inclusive of biofuel
- **Wires**: LUMA fixed O&M and FEMA/HUD cost share paid via rates
- **Administrative**: Contract fees for LUMA and Genera, HoldCo operating costs, legacy debt, PayGo pension, CILT and other subsidies, EE program costs, and bad debt

Between 2020 and 2025, the large increase in utility-incurred costs was driven by three key factors: investments to achieve an adequate generation fleet, costs of new energy efficiency programs, and PREPA's exit from bankruptcy (i.e., repayment of legacy debt and pension obligations). In the former case, although our scenario analysis obligated the utility to meet the 40% RPS requirement by 2025, the roughly 25% increase in generation-related expenses in that period reflected efforts to transition the electric system away from its fragile state of operation, which happened to be achieved with new renewable resources.[162] Across all of the scenarios, the utility's revenue requirement did not change substantially between 2025 and 2045. Even though additional Renewable Energy Generation costs were incurred to meet the increasing RPS requirements, they were offset by Thermal Energy Generation cost reductions along with lower

[161] Ideally, the FEMA/HUD cost share debt service costs would have been assigned to the Wires category and the transmission expansion debt service costs to support new third-party renewable projects would have been separately assigned to the Renewable Energy Generation category. However, due to the way the revenue requirements model was developed, these costs could not be separated. For that reason, the costs are jointly assigned to the Renewable Energy Generation category.

[162] We ran a sensitivity that relaxed the 40% RPS requirement but still incurred generation-related investments to achieve a more reliable electric system by 2025. The utility's generation-related costs, as well as the overall revenue requirement, were comparable to those incurred when the 40% RPS requirement was imposed. For details on this sensitivity, see the discussion in Section 8.4.2.1 (page 224).

Administrative costs, due to full repayment of legacy bankruptcy debt obligations and pension funding obligation declines. The ramp-up to achieve the 100% RPS requirement between 2045 and 2050 resulted in roughly 20% increase in the utility's revenue requirement, driven entirely by additional Renewable Energy Generation procurement costs and despite substantial Thermal Generation Cost reductions associated with fossil fuel-driven resource retirements.

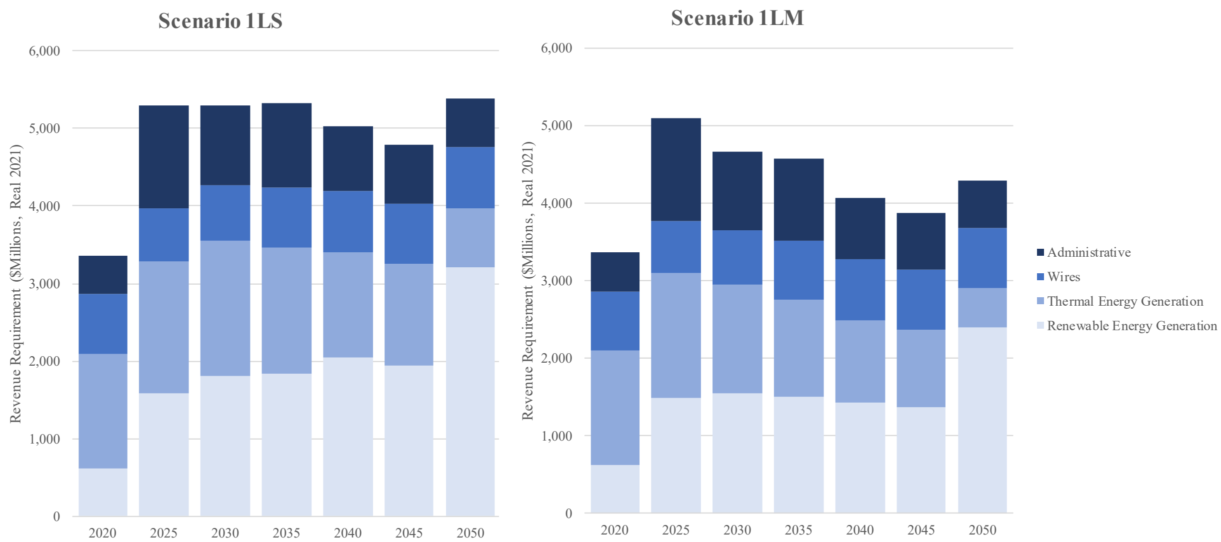

Figure 328. Revenue requirement components for the 1LS scenario and 1LM scenario

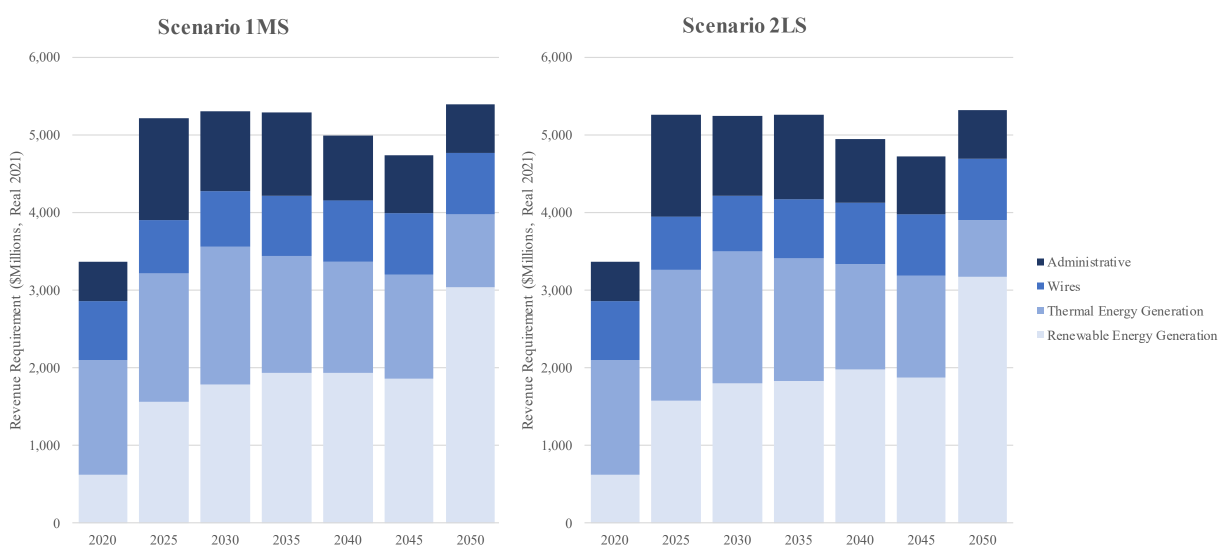

Figure 329. Revenue requirement components for the 1MS and 2LS scenarios

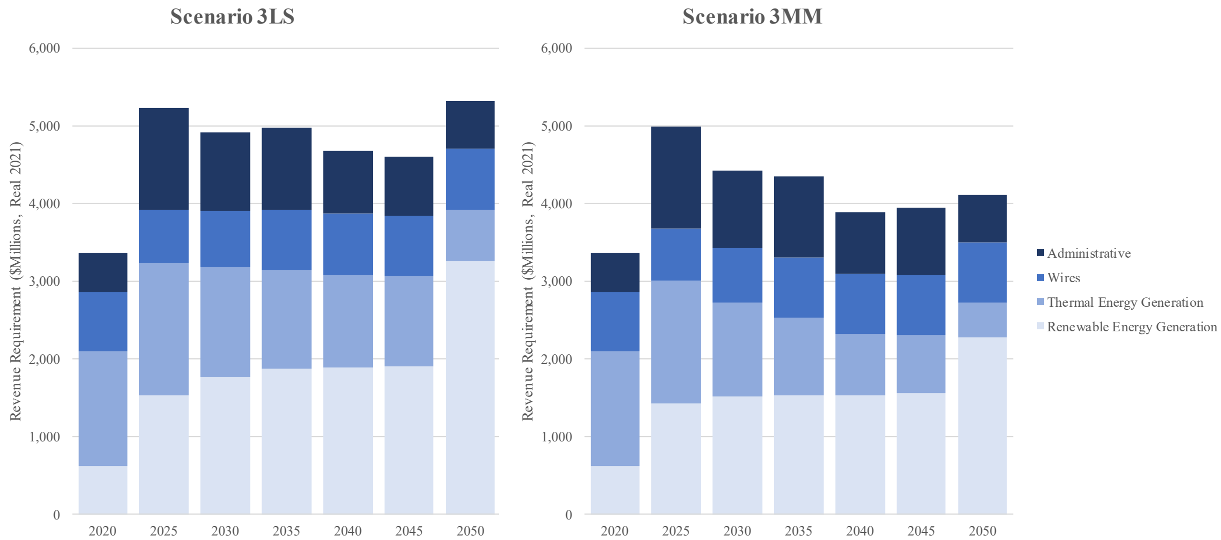

Figure 330. Revenue requirement components for the 3LS and 3MM scenarios

Over the course of the analysis period, our findings indicated a shift in the drivers of revenue requirement expenditures away from variable costs toward higher fixed or sunk costs over time. Utility-owned generation fuel costs and bad debt were considered to be the only truly variable costs in our analysis, meaning they were driven by changes in retail sales and represented ≈40% of the total revenue requirement in 2020 but dropped to roughly 11%–17% of the total revenue requirement by 2050, depending on the scenario (see Variable Costs Impacted by PR100 in Figure 332.

In contrast, the cost categories characterized as fixed or sunk were driven by the transition to a more reliable electric system in the near term and 100% renewable energy sources in the long-term (i.e., Legacy Generation fixed O&M, LUMA and Genera fixed O&M, purchased power costs, Genera contract fees, FEMA CapEx cost share borne by ratepayers, and new PREPA financed debt service). These grew over time, representing roughly 50% of the revenue requirement in 2020 and 2025 but growing to around 60% by 2045 and then jumping up to roughly 75% by 2050. The remaining revenue requirement elements (i.e., LUMA contract fees, HoldCo costs, legacy debt repayment, PayGo pension, CILT and other subsidies, and energy efficiency program costs) were considered fixed but unaffected by the achievement of Act 17-2019 RPS requirements (see Fixed/Sunk Costs Not Impacted by PR100 in Figure 332. They comprised roughly an equal share of the revenue requirement in 2020 (13%) as in 2050 (10%–13%)—although they rose and then fell again slightly in the intervening years (see Sunk/Fixed Costs Not Impacted by PR100 in Figure 332.

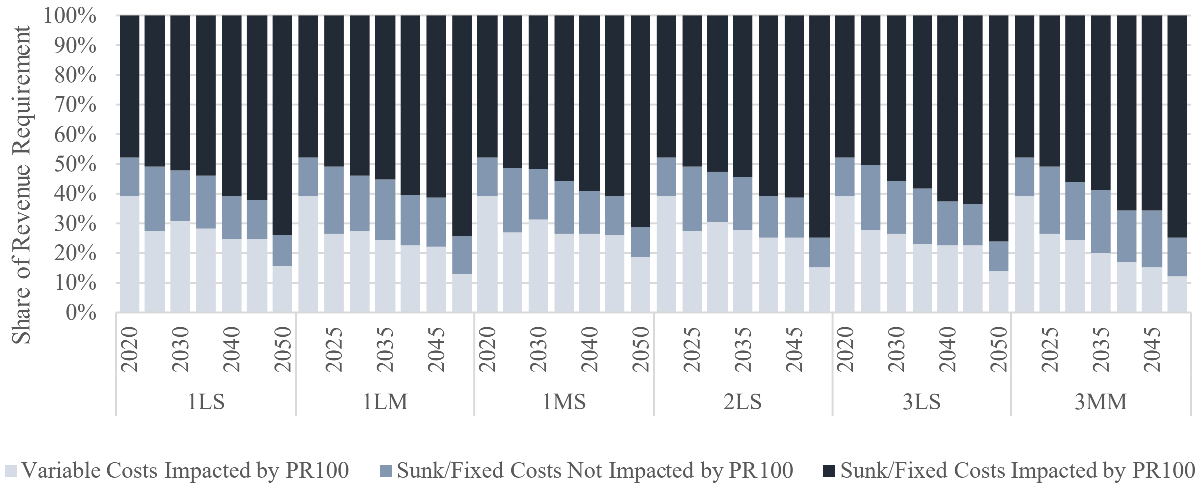

Figure 331. Share of fixed/sunk versus variable revenue requirement elements by impact of PR100

12.1.3.2 Utility Retail Rates

Our pro forma financial model derived all-in average retail rates based on the estimated revenue requirement (Figure 333).[163] Between 2020 and 2025, our analysis indicated that all-in average retail rates increased between roughly 65 to 80% from their starting level of 19.9 ¢/kWh, again due in large part to the cost increases associated with improving the reliability of the electric system. Thereafter through 2045, rates either decreased by up to 0.4% per year or increased by as much as 1.5% per year. The substantial increase in the revenue requirement between 2045 and 2050 to fully achieve the 100% renewable energy requirement caused all-in average retail rates to rise, jumping between 11% and 17%, depending on scenario.

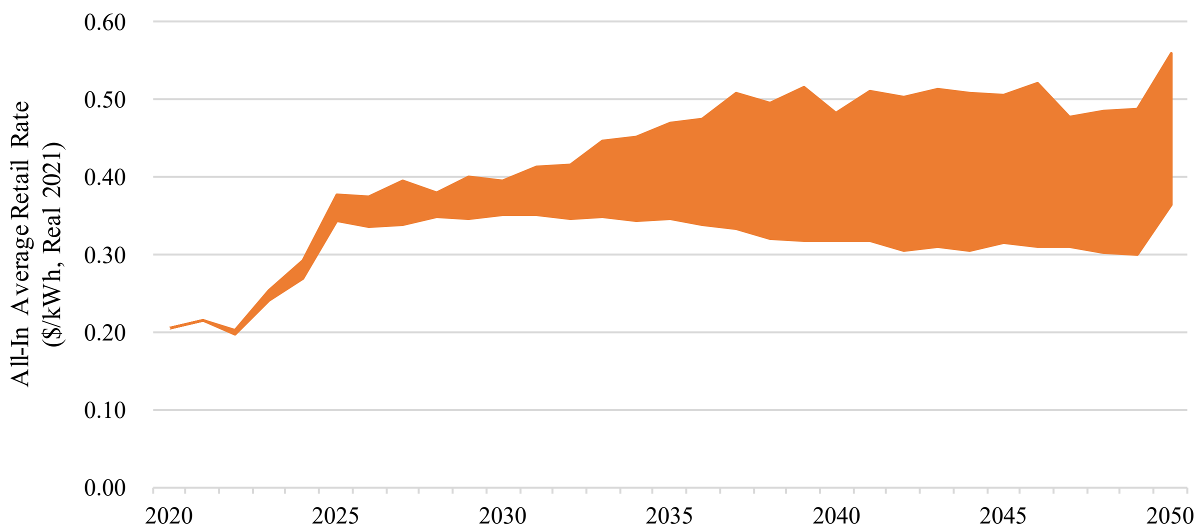

Figure 332. All-in average retail rate

[163] FOMB's 2023 Certified Fiscal Plan (FOMB 2023b) estimated the 2040 utility retail rate to be 42.8 ¢/kWh in real terms. This rate level fell within the range of our rate estimates in 2040, which are 31.8–48.3 ¢/kWh in real terms.

The share of the average retail rate assumed to be collected by rate riders generally increased over the analysis period. In 2020, rate riders comprised 65% of the all-in average retail rate. Our analysis indicated a rapid increase to around 75% of the average retail rate by 2025, driven by purchased power costs as well as PREPA's assumed emergence from bankruptcy. Thereafter, rate rider share of the average retail rate stayed around that level until 2050, at which point rate riders comprised between 75% and 80% of the average retail rate (Figure 334).

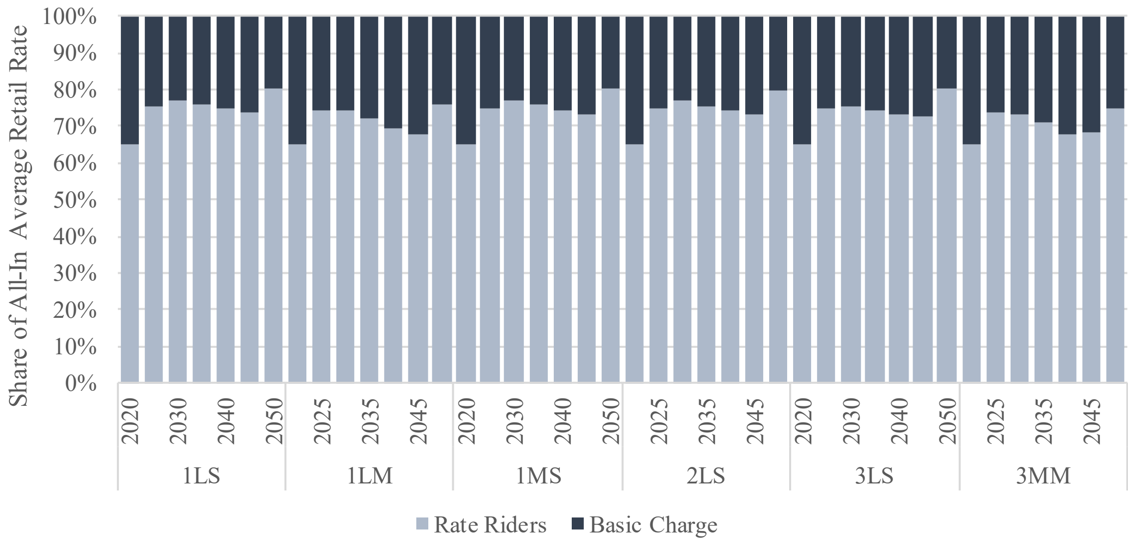

Figure 333. Share of all-in average retail rate via basic charge versus rate riders

Our pro forma financial model also derived estimates of all-in retail rates for each of our four simplified customer classes. The general trend in the rate level for each class (Figure 335, Figure 336, Figure 337, and Figure 338) was consistent with the trend observed for the utility-level all-in average rate—rate levels increased rapidly between 2020 and 2025, with a more varied but increasing range continuing through 2045, ending with another rapid increase through 2050.

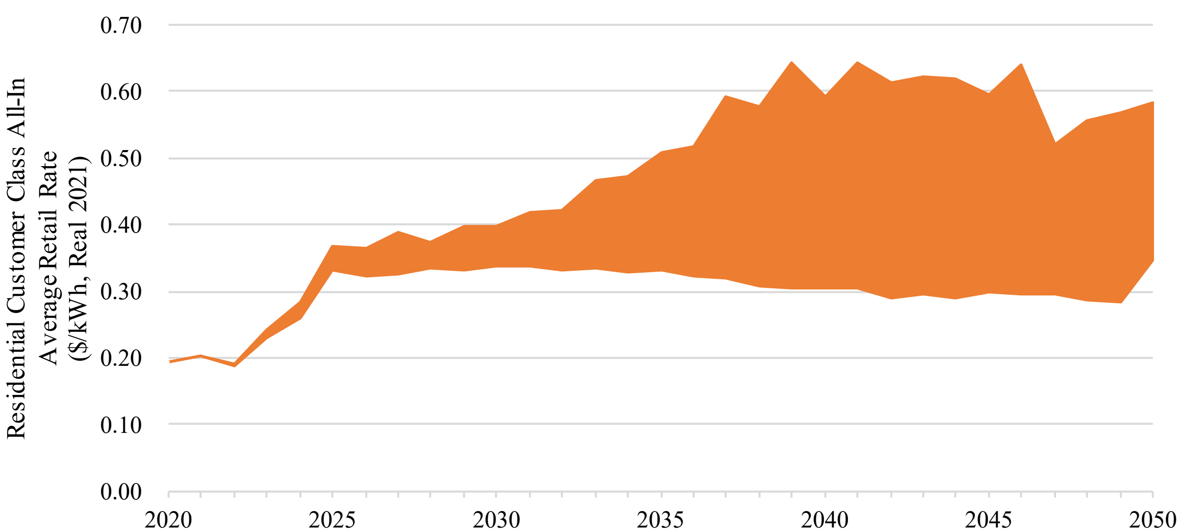

Figure 334. Residential customer class all-in average retail rate

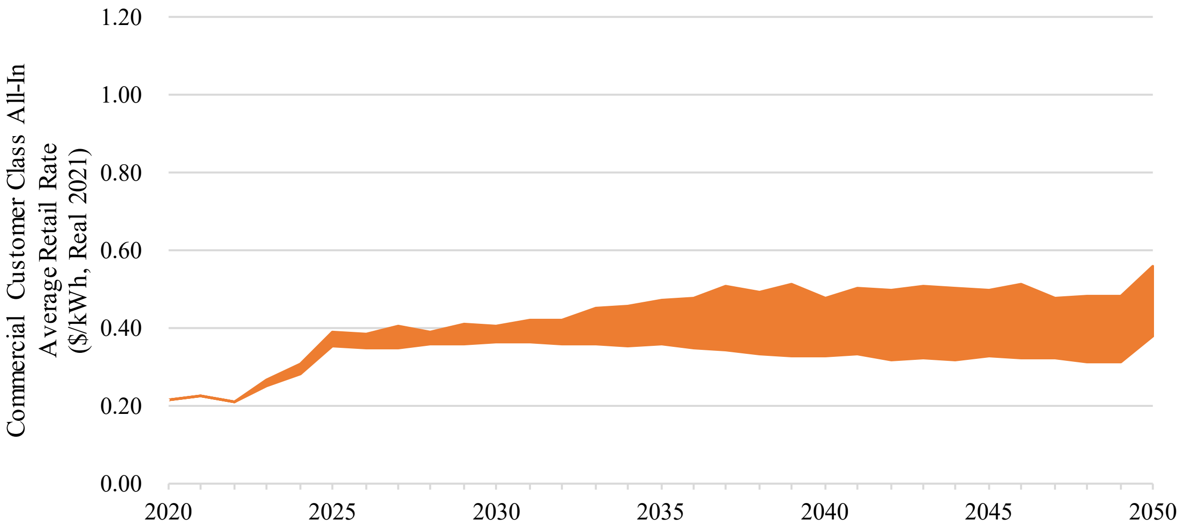

Figure 335. Commercial customer class all-in average retail rate

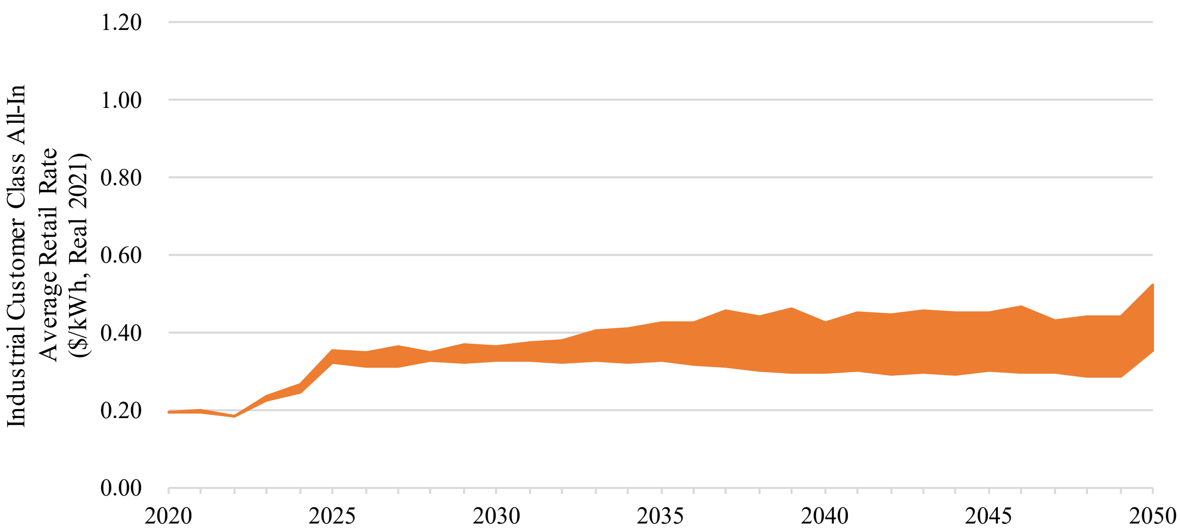

Figure 336. Industrial customer class all-in average retail rate

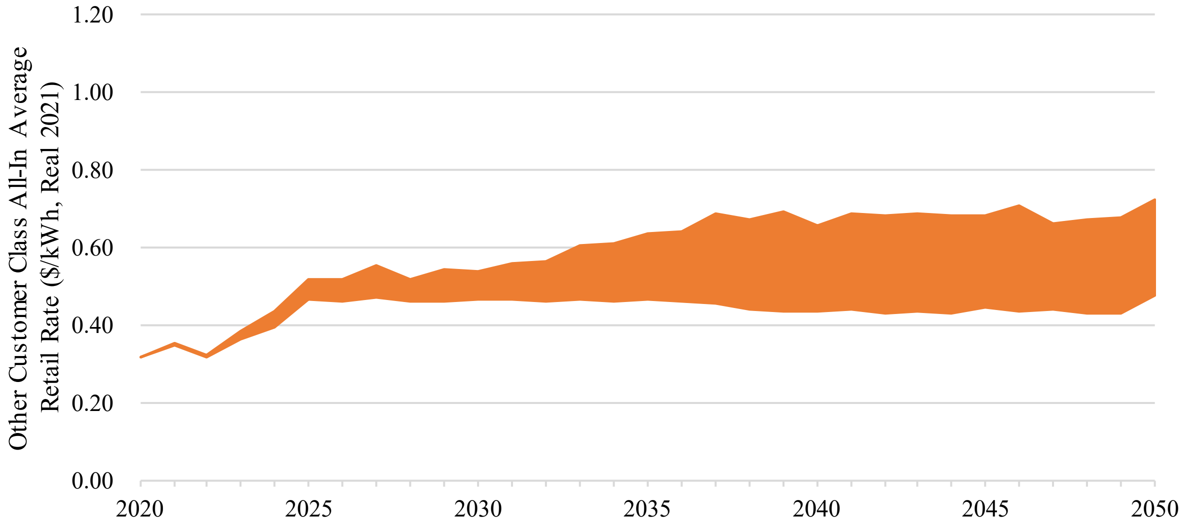

Figure 337. Other customer class all-in average retail rate

12.1.3.3 Average Residential Customer Utility Bills

Monthly bills were calculated for an average residential customer served on GRS and LRS rate schedules both before and after adopting a distributed PV (distributed PV) system. The distributed PV system was assumed to be sized to perfectly serve the customer's annual load.

An average residential GRS class customer adopting distributed PV in 2020 was expected to reduce their monthly utility bill from about $84/month to $4/month, avoiding all utility bill components except the monthly customer charge (Figure 339). By 2025, the impact was projected to grow even further because of the retail rate increases associated with all of the reliability improvement investments described in Section 12.1.3.2. The estimated utility bill for the class-average customer without distributed PV in 2025 ranged from $145/month to $166/month, depending on scenario, while the utility bill for a customer who had adopted a distributed PV system perfectly sized to meet their annual load was between $5 and $6/month. As the range in the retail rate continued to rise over the next 20 years, the range in utility bills for the average GRS customer who did not invest in distributed PV likewise continued to grow. By 2050, the utility bill for the class-average customer who did not invest in distributed PV ranged from $157/month to $287/month, depending on the scenario, while it ranged from $4/month to $7/month for those with distributed PV.

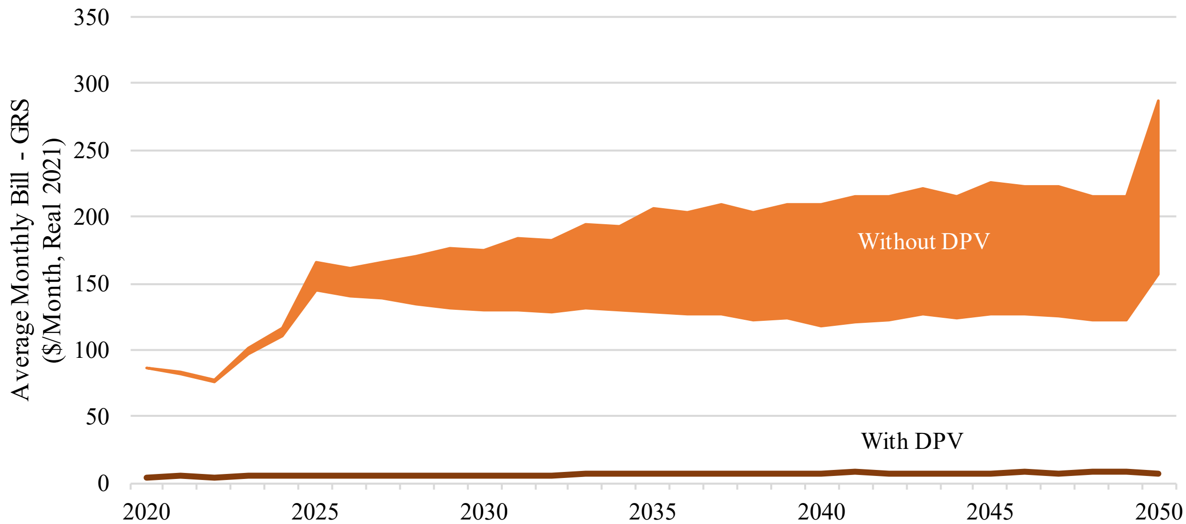

Figure 338. Average monthly bill for GRS customers

DPV is distributed PV.

Similarly, an average residential LRS class customer adopting a distributed PV perfectly sized to its annual load was expected to reduce their monthly utility bill considerably. In 2020, such an investment caused the monthly utility bill to change from about $50/month to $3/month, avoiding all utility bill components except the monthly customer charge (Figure 340). By 2025, the estimated impact grew even further because of the predicted retail rate increases associated with all of the reliability improvement investments described in Section 12.1.3.2. The utility bill for the class-average LRS customer without distributed PV in 2025 ranged from $84/month to $96/month, depending on scenario, while the bill for a customer who installed a distributed PV system perfectly sized to meet their annual load was around $4/month. As the range in the retail rate continued to rise, the range in utility bills for those who did not invest in distributed PV likewise continued to grow as well. By 2050, the utility bill for the class-average LRS customer who did not invest in distributed PV varied from $93/month to $170/month, while it ranged from $3/month to $5/month for those who did invest.

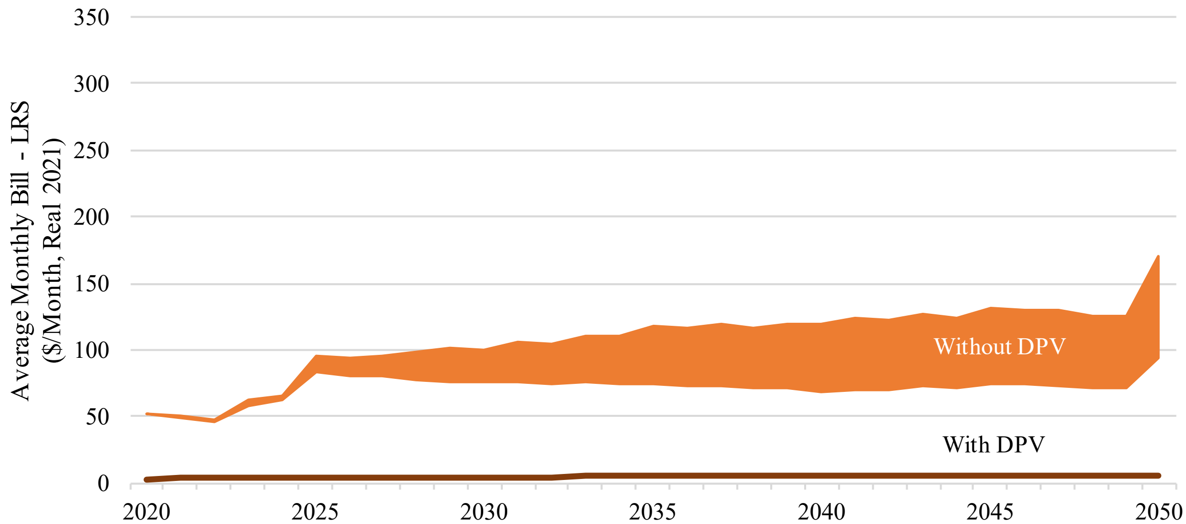

Figure 339. Average monthly bills for LRS customers

12.1.3.4 Impact of Land Availability Constraint

One of the key variations in our scenarios sought to better understand the impact of imposing constraints on the opportunity to develop utility-scale renewable energy resources on agricultural land. We assessed the economic implications when this constraint was imposed (the 1LS scenario: economic adoption, less land availability, and stress load) as well as when no such restrictions were applied (the 1MS scenario: economic adoption, more land availability, and stress load), keeping distributed PV adoption and the underlying load forecast constant. We were most interested in understanding whether the imposition of land constraints would increase the purchased power costs associated with new renewable energy resources required to meet Act 17-2019 requirements.

Our analysis showed that the assumed limits placed on the use of agricultural land for renewable energy development to meet Act 17-2019 requirement had a very small impact on the utility's purchased power costs (Figure 341). Up until 2035, purchased power costs are effectively identical across the two scenarios. From 2035 onward, imposing such constraints caused purchased power costs to change modestly, by roughly ±5%.

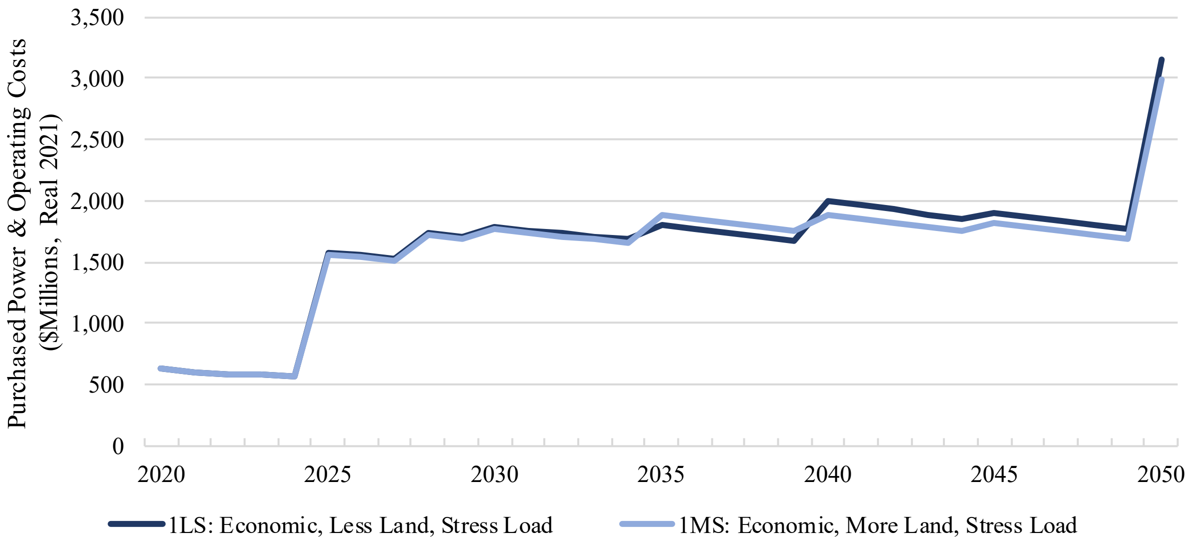

Figure 340. Purchased power and operating costs (1LS versus 1MS)

12.1.3.5 *Impact of Retail Sales Variation*

One of the other key variations in our scenarios sought to better understand the impact of differences in the demand for electricity. When changes in load were combined with the impacts of distributed PV adoption on utility costs, we can better understand the economic implications associated with changes in retail sales. To that end, we compared several key metrics across two scenarios. The first represented the highest level of retail sales (the 1LS scenario: economic adoption, less land availability, and stress load) while the second captured the opposite extreme, when retail sales were projected to be at their lowest (the 3MM scenario: maximum adoption, more land availability, and mid load). As shown in Figure 342, retail sales in 2050 drop from 2020 levels by 55% for the lowest forecast (3MM) relative to falling 10% for the highest usage forecast (1MS).

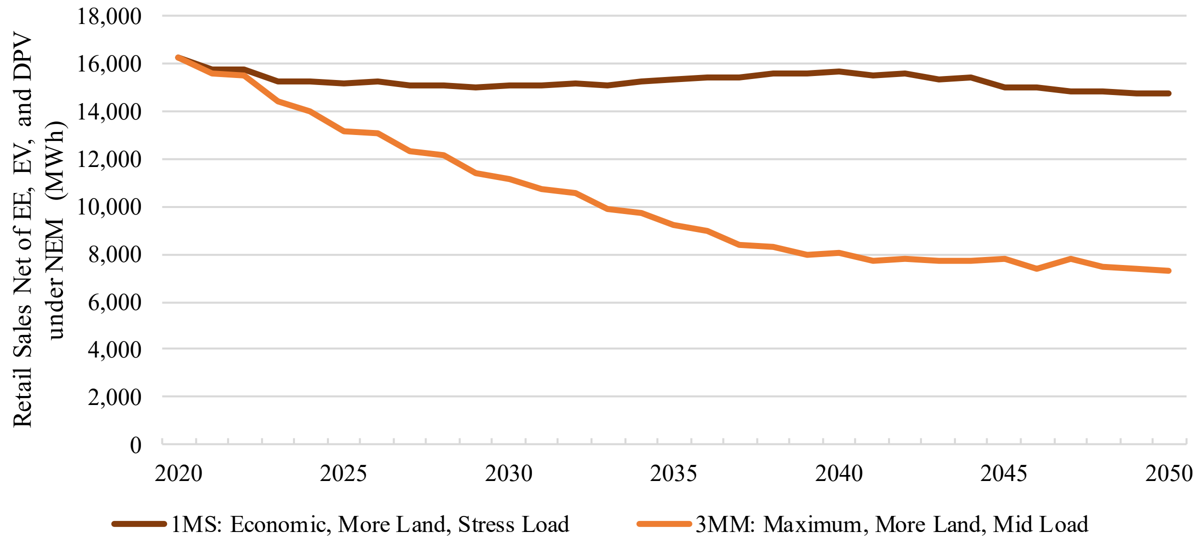

Figure 341. Retail sales net of EE, EV, and distributed PV under net energy metering (NEM) (1MS versus 3MM)

The stark reduction in retail sales between the two bookend scenarios had implications for the level of collected revenue each year, which affected the repayment of the legacy debt negotiated in the bankruptcy settlement. Lower annual legacy debt repayment occurs in the lowest retail sales scenario (Figure 343). As a result, the repayment date was extended by 4 years (Figure 343) for the 3MM scenario.

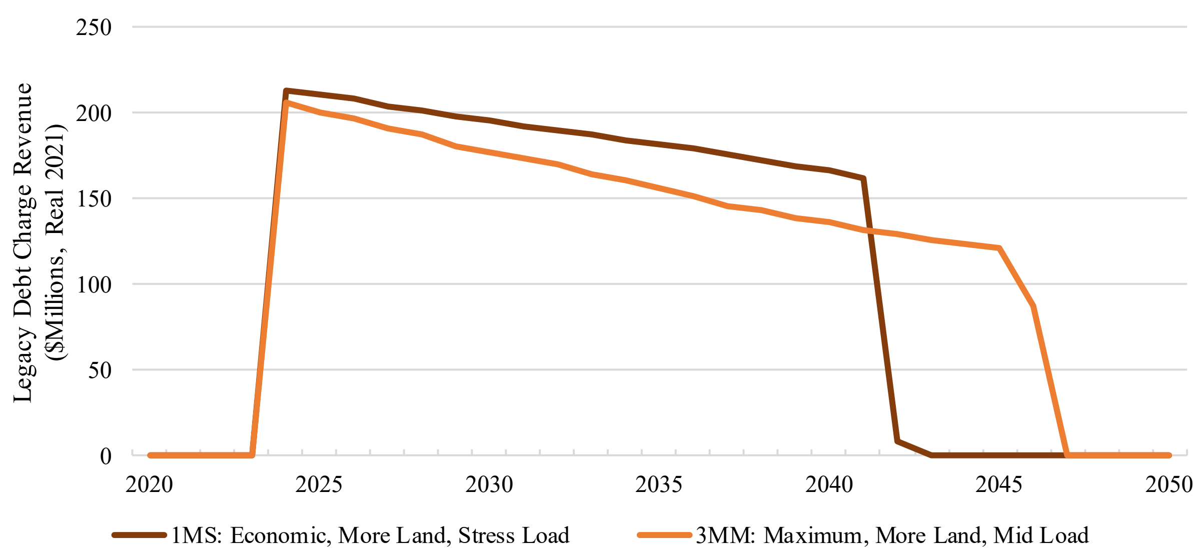

Figure 342. Legacy debt charge revenue (1MS versus 3MM)

The level of retail sales also had an impact on the costs incurred by the utility. As renewable energy penetration increased, the utility-owned fossil resources produced less energy overall but incurred additional cycling costs to manage the variability of the utility-scale renewable resources and, in conjunction with storage resources, was required to operate in ways that provided grid services that the utility-scale renewable energy resources could not. Although fossil generation costs were smaller when the retail sales level was at its lowest, this net impact was evident nonetheless. Furthermore, the achievement of 100% RPS in 2050 forced investment in a portfolio of new resources to provide the comparable grid services required to integrate distributed PV generation. As a result, the scenario with the lowest retail sales level experienced increases in generation production costs in 2050 that were smaller (35%) than the scenario with the highest retail sales level (Figure 344). The 50% reduction in sales in 2050 between these two scenarios did not translate into comparable reductions in the utility's revenue requirement. Indeed, the utility's revenue requirement for the scenario with the lowest retail sales level was only 24% lower than the revenue requirement under the highest retail sales level in 2050 (Figure 345).

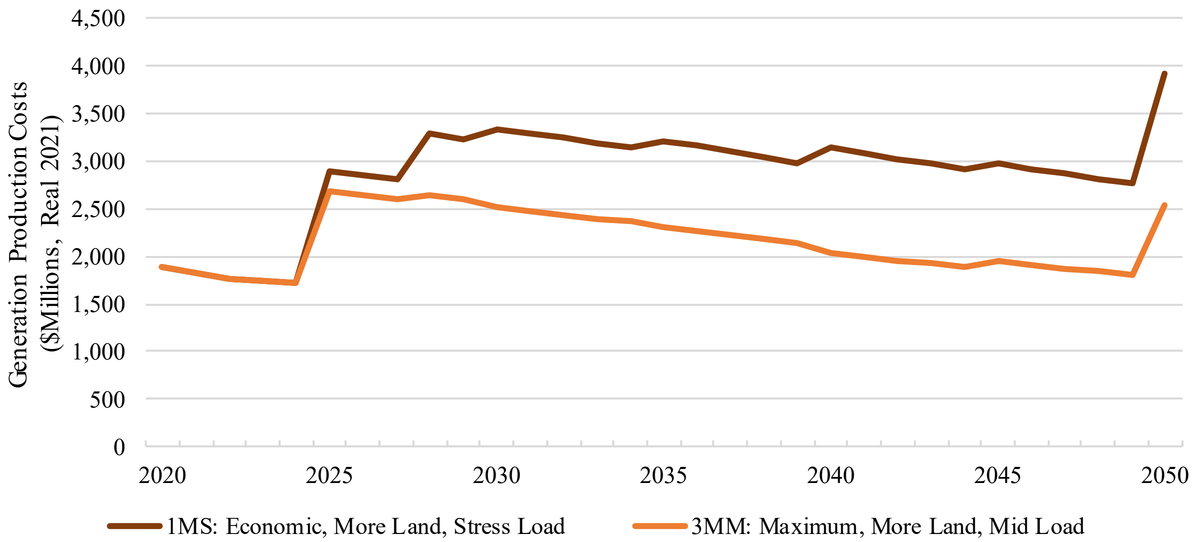

Figure 343. Generation production costs (1MS versus 3MM)

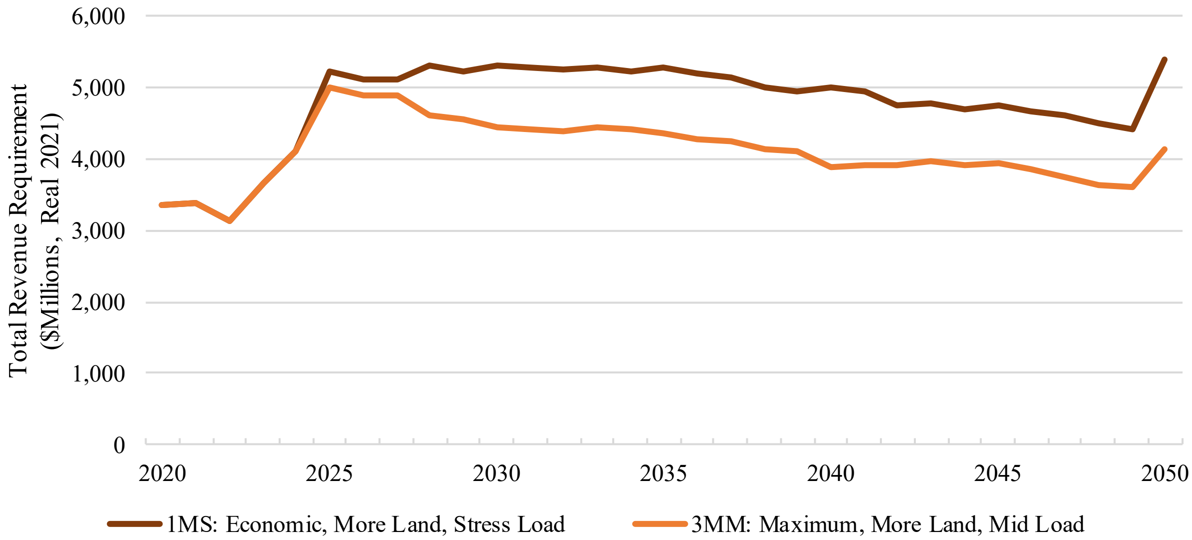

Figure 344. Total revenue requirement (1MS versus 3MM)

Because utility retail sales in the 3MM scenario declined so much more than utility costs, those costs had to be spread over a much smaller sales base to keep the utility financially healthy. This resulted in an increase in retail rates between 2025, when the electric system achieved a more reliable state of operation, and 2050: moving from 37¢/kWh to 56¢/kWh for the lowest retail sales level (Figure 346). In contrast, the retail rate level modestly drops between 2025 and 2045 for the highest retail sales level (34¢/kWh to 32¢/kWh) and then increases as the utility achieves 100% renewable energy penetration in 2050 (37¢/kWh) (Figure 346).

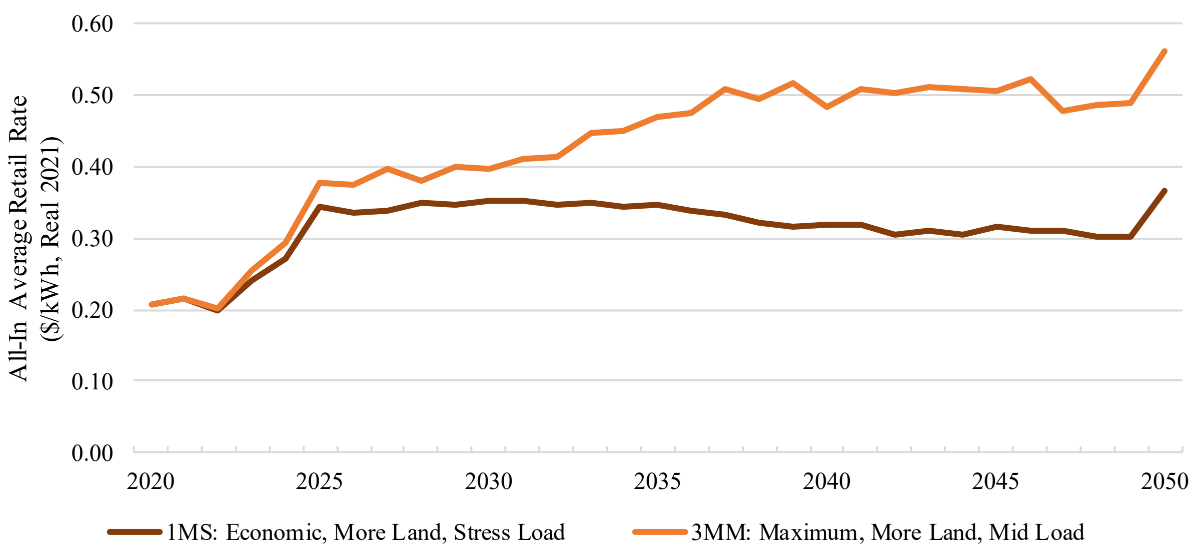

Figure 345. All-in average retail rate (1MS versus 3MM)

12.1.3.6 Impact of Utility-Scale Versus Distributed-Scale Renewable Energy Investment

The PR100 scenarios also varied by the level of utility-scale renewable energy investment and distributed-scale renewable energy investment. Because the capacity expansion modeling analysis sought to build utility-scale renewable energy after assessing what level of rooftop solar PV would be adopted, we can assess the economic trade-offs from the utility's standpoint associated with these different levels of investment in the extreme: maximum utility-scale renewable energy investment under the 1LS scenario (economic adoption, less land, and stress load) versus maximum distributed-scale renewable energy investment under the 3MM scenario (maximum adoption, more land, mid load).

One of the key economic impacts from the trade-off between distributed-scale and utility-scale renewable energy investment is that in the former case, individual customers pay for that investment directly whereas in the latter case the utility incurs that cost and passes it through to its customers. As a result, the utility's generation production costs were consistently lower because the system saw more distributed-scale renewable energy investment undertaken directly by interested customers and less utility-scale renewable energy investment which was funded by the utility via all of its ratepayers (Figure 347). By 2050, utility-incurred generation production costs were 35% lower in the 3MM scenario versus the 1LS scenario.

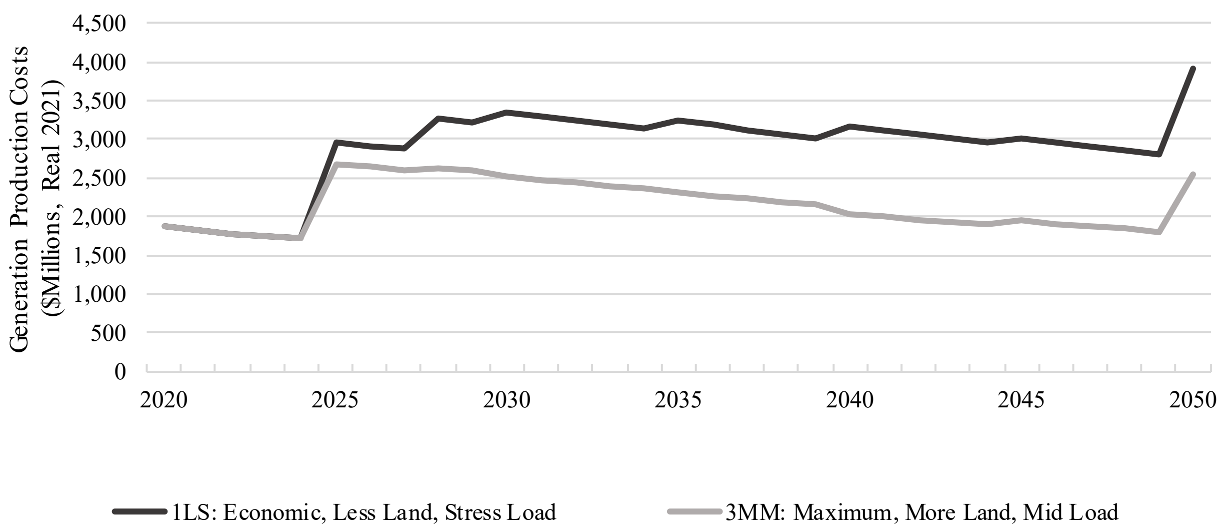

Figure 346. Generation production costs (1LS versus 3MM)

This result largely drove a somewhat similar outcome for the utility's revenue requirement. Starting in 2025 after utility generation-related investments were made to achieve a reliable and stable electric system, the total revenue requirement consistently dropped through 2045 for both scenarios and was consistently lower for the highest level of distributed-scale RE adoption than for the highest level of utility-scale RE adoption (Figure 348). By 2050, when the utility achieved its 100% renewable energy goal, the total revenue requirement was roughly the same (2%) or considerably lower (-17%) than it was in 2025 for the highest level of utility-scale RE adoption and the highest level of distributed-scale RE adoption, respectively, but was 24% lower in 2050 for the 3MM scenario relative to the 1LS scenario.

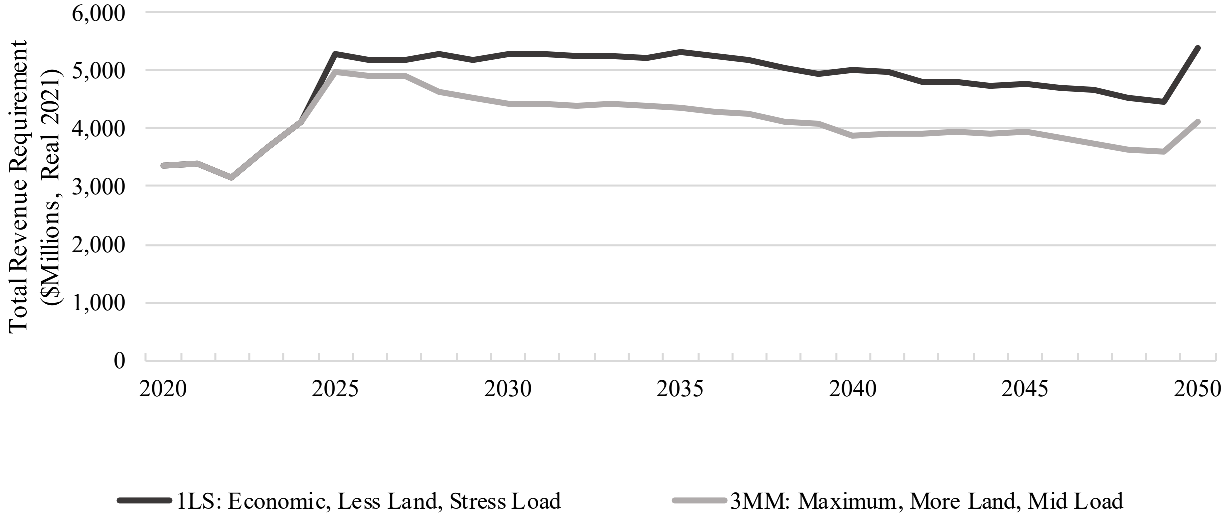

Figure 347. Total revenue requirement (1LS versus 3MM)

Because the level of distributed PV adoption affects the level of retail sales, the utility saw a consistently lower level of retail sales net of EE, EV, and distributed PV production (because of net energy metering [NEM]) for the highest level of investment in distributed-scale renewable energy resources than for the highest level of utility-scale renewable energy resource investment (Figure 349). By 2050, the highest level of distributed PV adoption resulted in retail sales that were 50% lower than when the highest level of utility-scale renewable energy resource occurred.

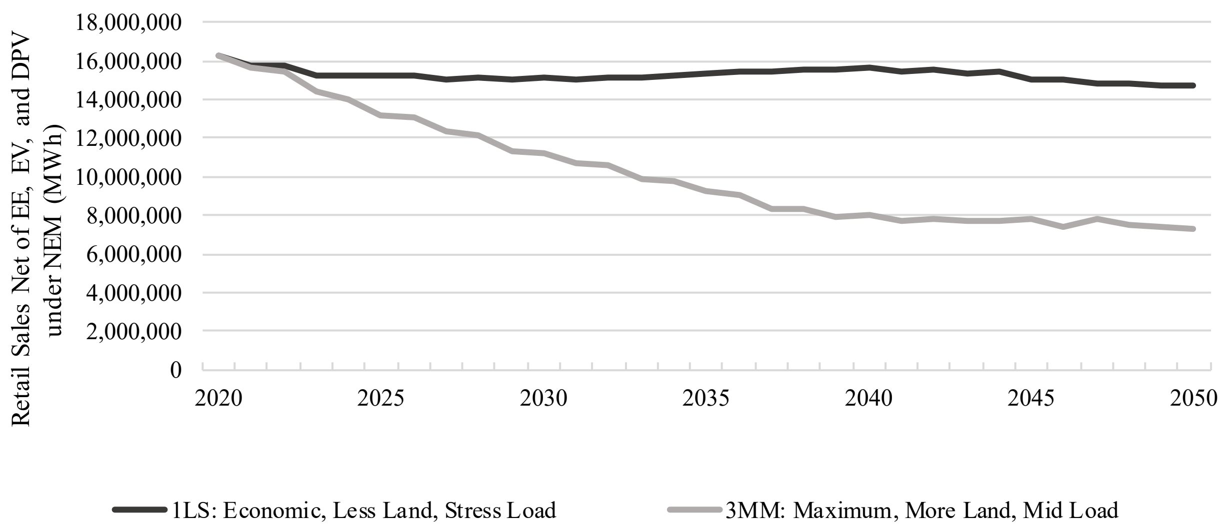

Figure 348. Retail sales net of EE, EV, and distributed PV under NEM (1LS versus 3MM)

Because utility retail sales declined while utility costs rose, those higher costs must be spread over a much smaller sales base to keep the utility financially healthy. As a result, utility retail rates were consistently higher for the highest penetration level of distributed-scale renewable energy resources than for the highest penetration of utility-scale renewable energy resources. In 2050, utility retail rates were 56¢/kwh for the highest distributed-scale renewable energy resource penetration level, which was 53% higher than rates for the highest utility-scale renewable energy resource penetration level.

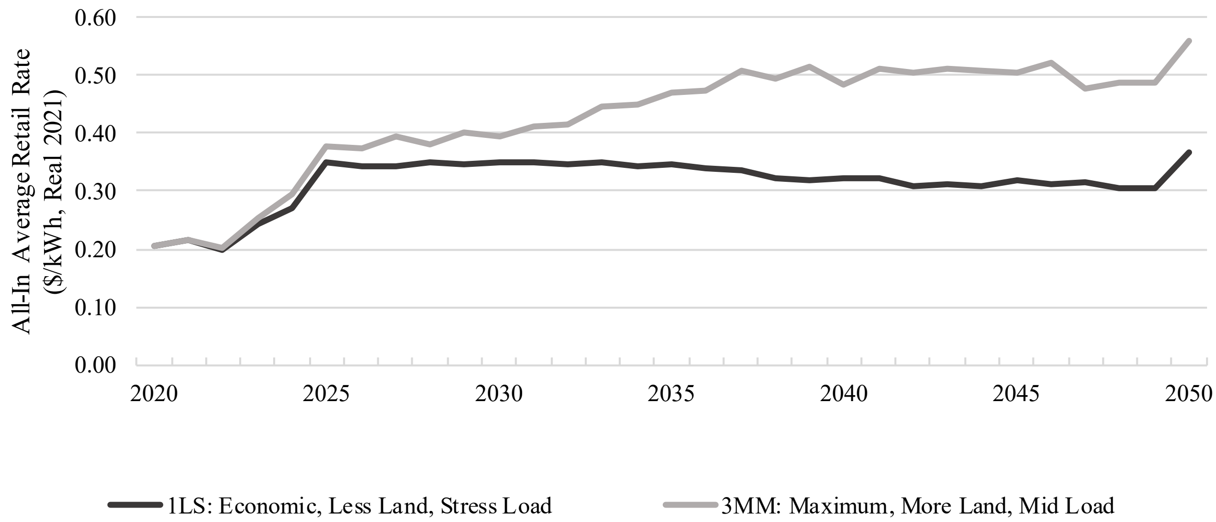

Figure 349. All-in average retail rate (1LS versus 3MM)

12.1.3.7 Impact of Distributed-Scale Renewable Energy Investment Variation

Because the capacity expansion modeling, production cost modeling, and distribution system modeling analyses quantify the impacts associated with different levels of distributed solar PV adoption, we can assess the economic trade-offs, from the utility's standpoint, associated with these different levels of investment holding land availability constraints and the load forecast constant: minimum level of distributed PV adoption under the 1LS scenario (economic adoption, less land, and stress load) versus intermediate level of distributed PV adoption under the 2LS scenario (equitable adoption, less land, and stress load) versus maximum level of distributed PV adoption under the 3LS scenario (maximum adoption, less land, stress load).

As discussed in Section 12.1.2.3 (page 407), increasing levels of distributed PV adoption under NEM resulted in increasing distributed PV production (MWh) that could not be integrated on the distribution system without additional infrastructure investments (Figure 351).[164] By 2050, the level of exported energy requiring integration investments for the highest level of distributed PV adoption was roughly 2.5× higher than it was for the lowest level.

[164] Because of timing issues with completing our analysis, the economic impact analysis (Task 10) relied on a preliminary set of results from the distribution grid impacts analysis (Task 9). Because these preliminary levels of excess exported energy were slightly smaller in magnitude than the results described in Section 11 (page 345), the additional battery storage resources contracted for under PPOAs would likely have been slightly larger than we represented here. However, as discussed later in this section, the size of these costs relative to the entire utility's revenue requirement was minimal. Therefore, although the revenue requirement would likely be slightly larger had we been able to incorporate these results from Task 9, the size of that increase would likely be minimal. (All PR100 tasks are listed in Figure 2, page 7.)

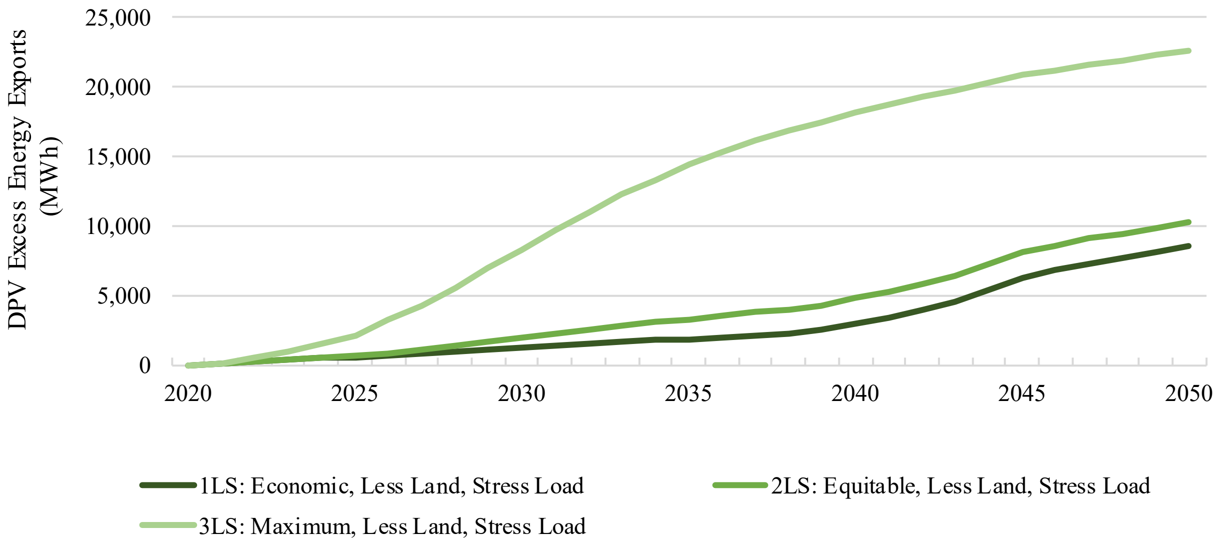

Figure 350. Distributed PV excess energy exports (1LS versus 2LS versus 3LS)

Our analysis assumed the front-of-the-meter storage identified in the analysis discussed in Section 10 could be deployed at the distribution level to support these integration needs. By 2037, distribution system upgrades in the form of storage procured under PPOAs in addition to the requirements identified in Section 8.4.2 (page 225) began to be needed to mitigate the integration challenges by the highest distributed PV adoption scenario under NEM (Figure 352).

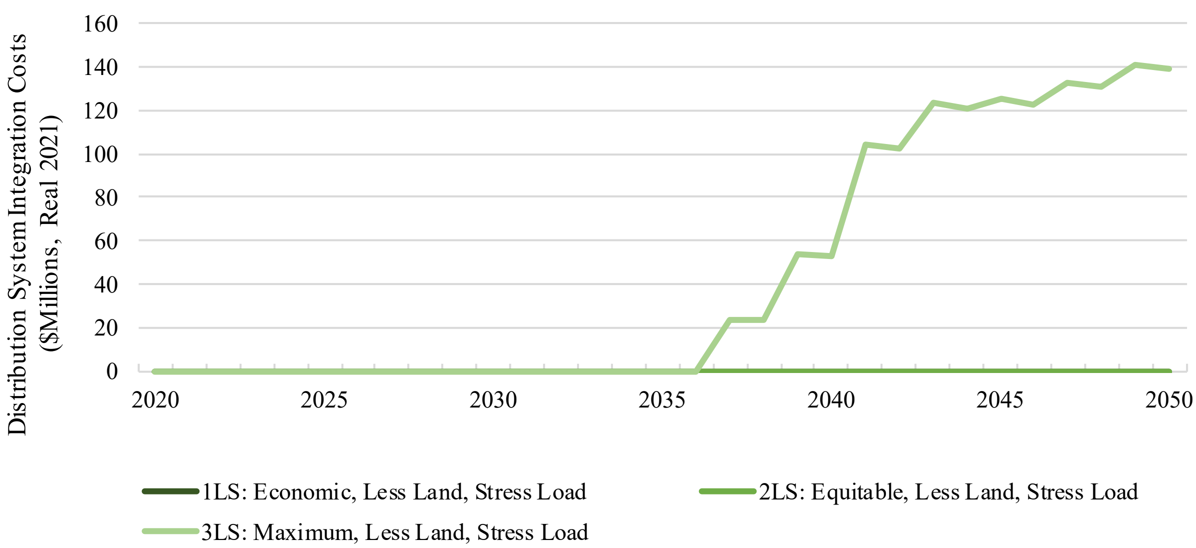

Figure 351. Distribution system integration costs (1LS versus 2LS versus 3LS)

At the bulk system level, electricity from these distributed PV systems reduced the amount of utility-scale generation resources required to meet annual energy demand, but the increased level of variability introduced into the net load profile caused offsetting integration costs. Starting in 2025, utility-owned generation cost savings (%) from the highest level of distributed PV relative to the lowest level of distributed PV were modest but not as large, in percentage terms, as the reductions in retail sales between these two scenarios (Figure 353). However, purchased power costs were nearly identical across the three levels of distributed PV adoption (Figure 354). Starting in 2040, both utility-owned generation and purchased power cost reductions were much smaller, in percentage terms, than the change in retail sales reductions from distributed PV between the highest and lowest level of distributed PV adoption. At the levels of distributed PV penetration seen in the 3LS scenario, the utility incurred substantially more distributed PV integration costs under NEM that offset nearly all the savings from the lower electricity demand.

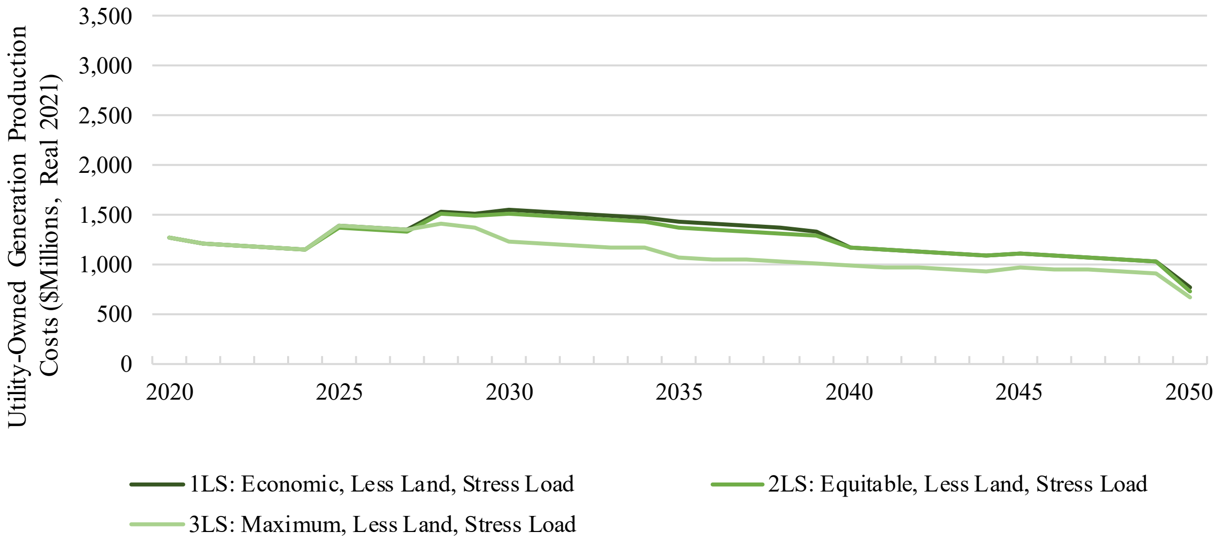

Figure 352. Utility-owned generation production costs (1LS versus 2LS versus 3LS)

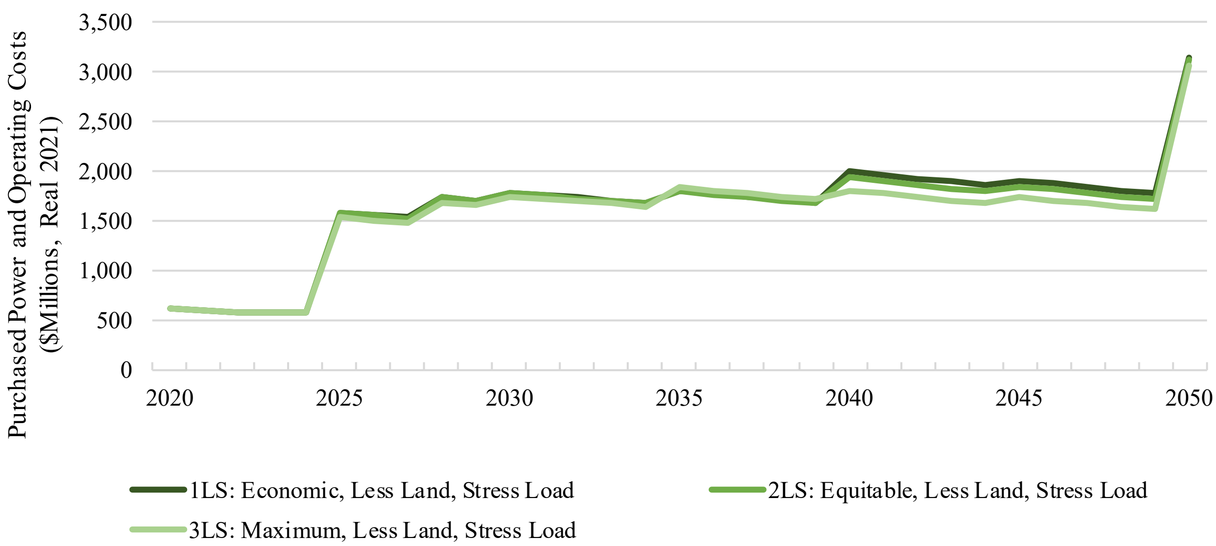

Figure 353. Purchased power and operating costs (1LS versus 2LS versus 3LS)

The net impact of slightly lower generation production costs overall was almost but not entirely offset by higher distribution system battery costs for the highest distributed PV adoption level under NEM. As a result, the total revenue requirement under the highest penetration level of distributed PV was only 1% lower than it is for the lowest penetration of distributed PV in 2050

(Figure 355). With nearly identical total revenue requirements, the 21% reduction in retail sales (1LS scenario versus 3LS scenario) in 2050 caused rates to be higher by 26% (Figure 356).

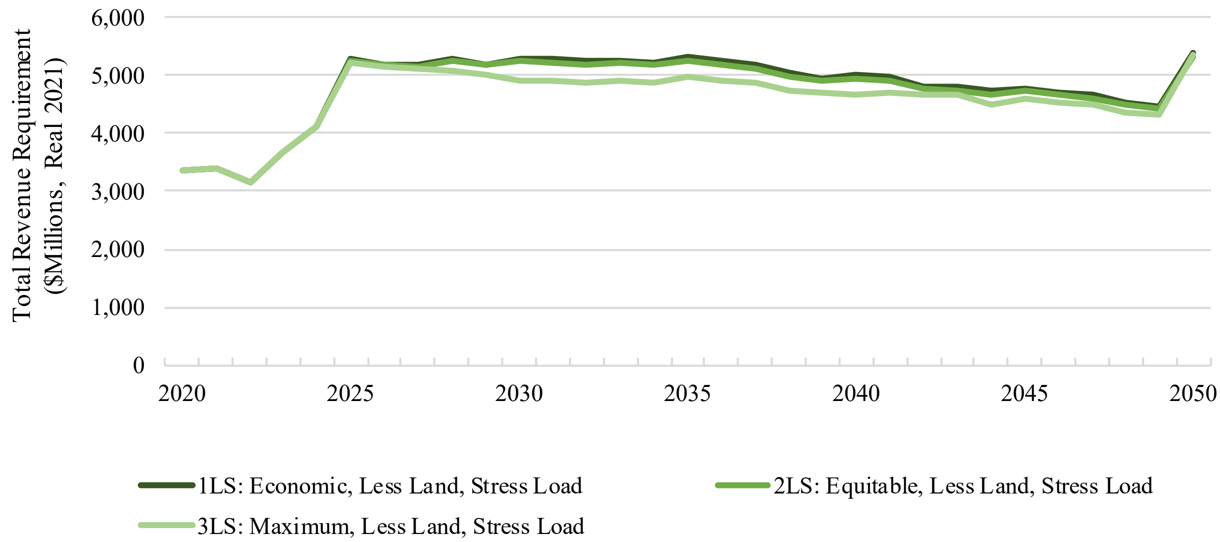

Figure 354. Total revenue requirement (1LS versus 2LS versus 3LS)

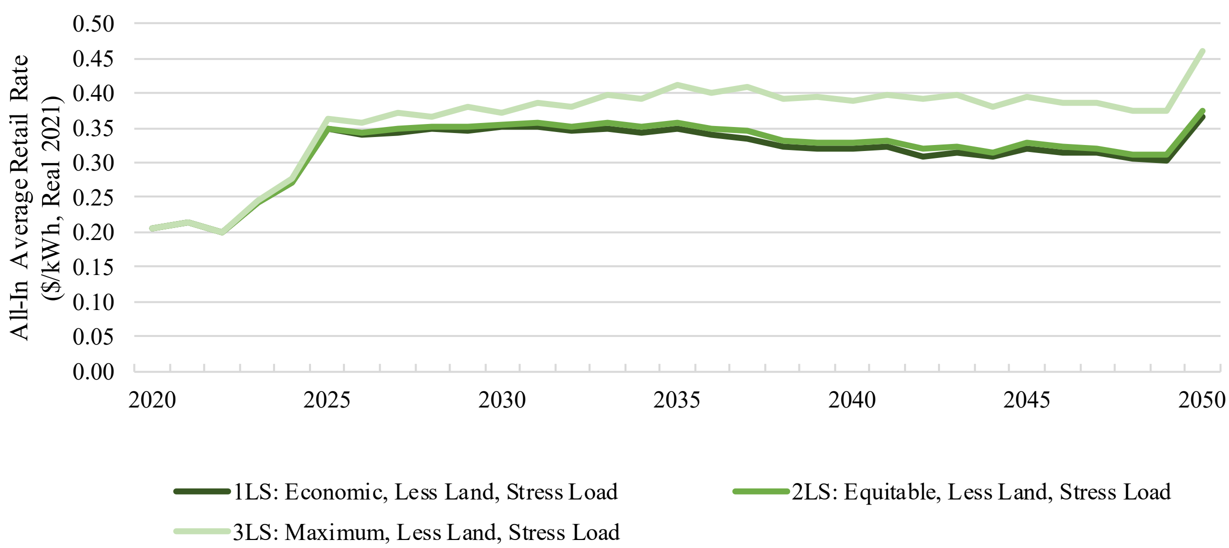

Figure 355. All-in average retail rate (1LS versus 2LS versus 3LS)

The increase in retail rates with higher levels of distributed PV adoption more adversely affected those without distributed PV than those with distributed PV. In any given year, the class-average bills of nonadopters of distributed PV who were either GRS customers (Figure 357) or LRS customers (Figure 358) consistently rose as distributed PV adoption levels under NEM increased. There was minimal difference in bills between the economic and equitable distributed PV adoption levels in 2050, but the maximum adoption levels caused bills to rise another ≈25% relative to these two lower distributed PV adoption levels.

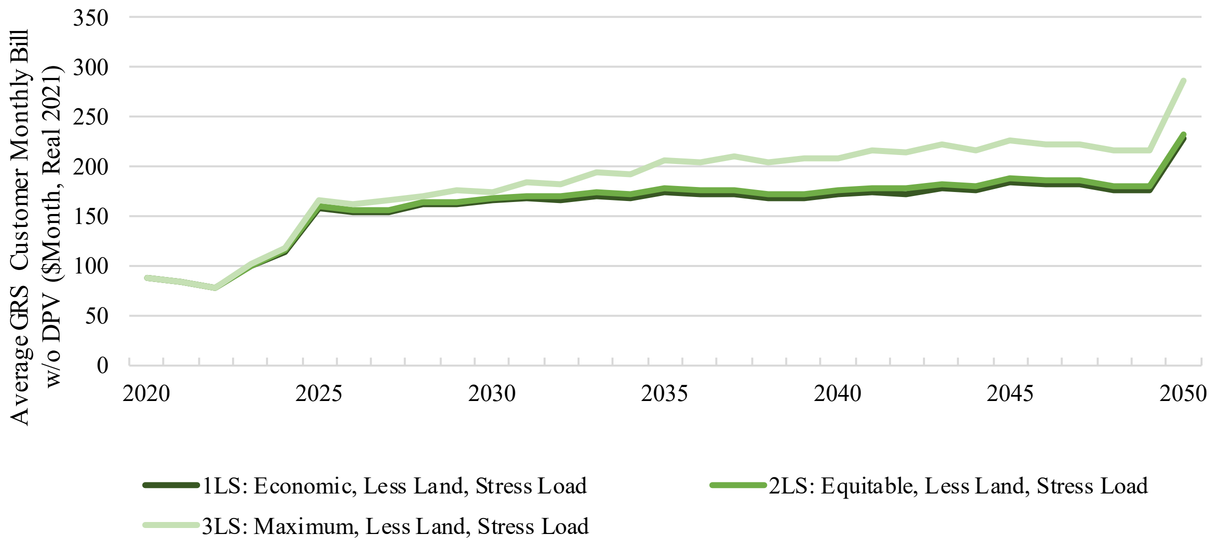

Figure 356. Average GRS customer monthly bill

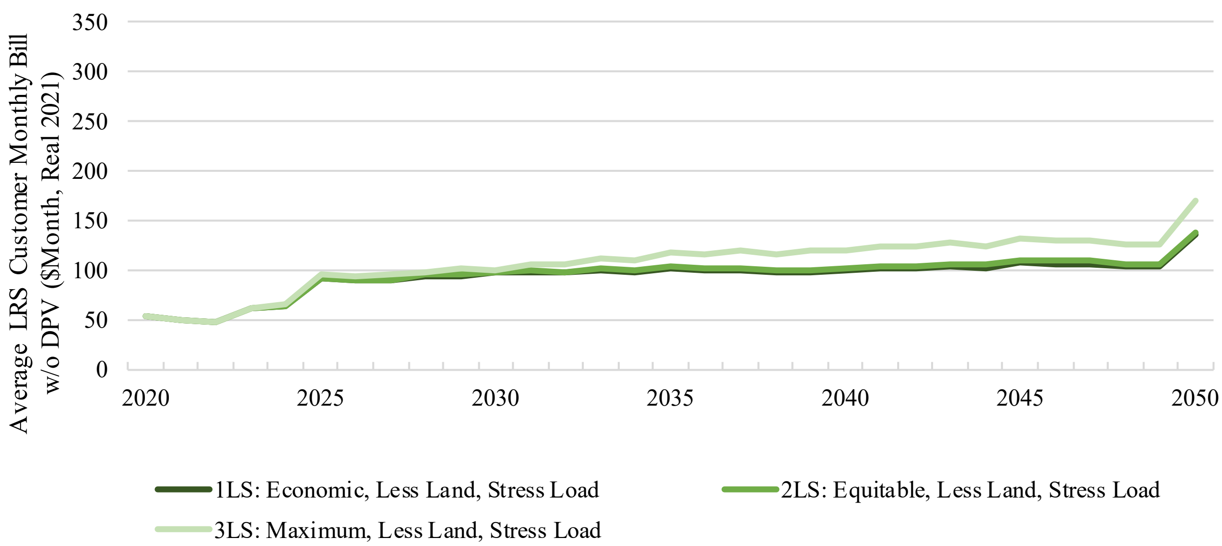

Figure 357. Average LRS customer monthly bill

12.1.4 Discussion

These results suggest three distinct but interrelated challenges facing Puerto Rico as it seeks to transition to 100% renewable forms of energy.

First, the PR100 project developed scenarios representing increasingly higher levels of distributed PV and storage system adoption in response to both current trends and widescale stakeholder support for increased future penetration. Our analysis indicated that increases in distributed PV adoption reduced retail sales and therefore were a key driver of the estimated increases in rates and by extension led to higher bills for nonadopters. These distributed PV systems under NEM effectively encroached on the utility's role in providing energy to the customer, but the utility was also required to integrate these uncontrolled distributed PV exports. PR100 further assumed distributed storage systems, which customers are increasingly investing in, provided resilience during electricity outages but did not supply any grid services.

Second, PR100 assumed the transmission and distribution grid was rebuilt to replicate how it was configured prior to Hurricanes Irma and Maria. This electric system, and the utility structure that supports it, is predicated on a network planning and operating model which leverages economies of scale and is consistent, in principle, with the early electric companies formed at the dawn of the industry. Our PR100 analysis maintained that structure and role for the utility, taking into account the transition of managerial responsibility to a GridCo, GenCo, HydroCo, PropertyCo and HoldCo as required under Act 120-2018 and Act 17-2019.

Third, rates were set to fully collect the utility's annual revenue requirement, and thereby ensured the financial health of the utility. These same rates, however, produced adverse impacts on the financial health of the utility's ratepayers—the citizens and businesses of Puerto Rico.[165] Low-income customers, the least likely to be able to afford distributed PV and battery systems, were more adversely affected by higher rates than other customers, resulting in clear implications for energy justice in this transition.

When these three factors are taken together, PR100 analyzed a highly centralized utility in a future that was increasingly comprised of distributed and decentralized electricity resources which were neither owned nor controlled by the utility. Our analysis illustrates the implications of this seemingly dichotomous future: utility costs could not be reduced as quickly as retail sales resulting in higher retail rates.

However, PR100's estimates are unlikely to perfectly capture how the future unfolds in Puerto Rico. Given these projected increases in retail rates, Puerto Rico's policymakers and regulators are likely to mitigate them and their impacts. Everyone would likely benefit if policymakers consider the financial health of both customers and the utility while developing viable solutions that both reliably and sustainably serve future loads and avoid utility bankruptcy. Although Act 17-2019 envisioned customers as active prosumers, more fundamental reforms will likely be needed first regarding the roles and responsibilities of the utility as well as its customers to achieve this prosumer future while also providing an acceptable level of reliability and resilience that meaningfully and substantially reduces the utility's costs. In addition, a reassessment of the prioritization of grid and customer investments could benefit regulators and stakeholders who are determining how to best support these re-envisioned roles and responsibilities. Such a reassessment could be part of more integrated and comprehensive long-term planning efforts that incorporate the prosumer future and perhaps re-imagine the structure of the grid and the role of the utility. Lastly, regulators could examine potential impacts of redesigned retail rates and distributed generation compensation schemes to identify options that achieve efficient system operation and support equitable solution.

[165] The broader impact of these rate increases on the Puerto Rican economy is discussed in more detail in Section 12.3 (page 474).

12.1.5 Considerations

Considerations that are based on this section's key findings include that Puerto Rico:

- Work to reduce the utility's revenue requirement will require more integrated and potentially longer-term planning efforts that consider all opportunities to reduce integration costs of increasingly greater levels of variable renewable generation resources.
- Redesign retail rates to improve the temporal alignment between the types of costs incurred (i.e., sunk/fixed versus variable) and the types of charges employed to recover those costs (i.e., fixed versus variable) will be increasingly important to support the utility's financial health.
- Mitigate revenue shifts to nonparticipants, address equity and energy justice concerns, and support opportunities that reduce utility costs while capturing broader societal benefits related to renewable generation with the help of distributed PV compensation reform.

12.2 Gross Macroeconomic Impact Analysis

Key Findings

- Construction and installation efforts create more than 6 times the number of jobs associated with O&M efforts on average. However, O&M efforts are permanent lasting jobs with higher associated labor hours as compared to single-year construction efforts.
- Construction and installation jobs, which are nonpermanent, earn more than the O&M jobs that are last postconstruction. Averaged across occupations, worker earnings are generally higher than the median wage.
- Higher levels of distributed solar adoption led to higher job creation both during the construction/installation phase as well as during the operation phase. However, the balance between O&M jobs created from distributed solar is 38% versus utility-scale solar with 44% on average.
- There is a dramatic boom-bust-boom-bust cycle in construction/installation jobs to initially meet the 2025 40% RPS requirement and later meet the 2050 100% RPS requirement. This volatility is even more extreme when focusing on utility-scale jobs where 4,700 construction jobs are needed through 2026 but then drops back to 300 jobs through 2045.
- In contrast to construction/installation jobs, there is considerably more stability in O&M jobs that steadily ramps up over time because of more energy assets being deployed over time.

Considerations

- Ensure an ample workforce is available with the occupational skills needed across both phases of development, given the level of demand for workers needed for construction and O&M efforts, both of which are skill intensive.
- Source workers locally to allow the economic benefits to remain within Puerto Rico. Outsourcing labor outside of Puerto Rico can create obstacles when a labor force cannot meet the workforce demands (e.g., migration and temporary housing). With Puerto Rico's geography, sourcing more labor outside of the Commonwealth can complicate the workforce dynamics and have economic benefits leave the region.
- Consider the right balance between job training efforts to create a local workforce that supports sustainable employment opportunities and outsourcing additional jobs to non–

Puerto Rico entities. This could address the extreme volatility in construction/installation jobs between now and 2030 and then again between 2040 and 2050. Restructuring the RPS could also help mitigate this volatility.

- Develop effective and efficient job training programs to create a sustainable local workforce in time, as growth in O&M jobs is relatively stable.
- Ensure that a workforce, which is sourced locally, has the skillset needed to achieve the levels of deployment envisioned under Act 17, as well as the capacity of infrastructure, such as port access and availability for the sheer amount of equipment and materials being shipped in, can allow these impacts to manifest.

12.2.1 Introduction

Transitioning to an electric grid run on 100% renewable energy will involve major capital investments in the form of construction and installation of such technology as well as the professions necessary to operate and maintain them. Such expenditures have immediate and long-lasting impacts on the economy in Puerto Rico. Such investments as the balance of system costs, the local economic impacts, and benefits are essential to this study. In this section, we assess the gross economic impacts and jobs associated with selected scenarios from PR100.

In this section, we set out a framework and use the Jobs and Economic Development Impact model built for Puerto Rico. This analysis leverages multipliers from IMPLAN—capital and operational expenditures for specific energy technologies to estimate the local economic impacts from the investments made in the territory. The modeling framework employs inputs from other tasks and data specific to Puerto Rico and allows for the analysis of solar and wind. The economic indicators generated by the Jobs and Economic Development Impact (JEDI) models are the total number of local jobs in terms of full-time equivalent (FTE),[166] earnings, and value added (GDP). JEDI uses investments made into construction and O&M to estimate economic impacts in the form of jobs, earnings, GDP, and total industrial output. Capital investments are captured under the construction and installation phase during the deployment of energy assets during the transition as well as investments made in association with the ongoing O&M after construction and installation is complete.

Next, we then investigate the total local economic impacts associated with the level of capacity being installed for six scenarios across the scenario types and variation. Six scenarios across the total number of variations for the deployment of renewable energy into Puerto Rico's electric grid were analyzed through JEDI to estimate the range of economic impacts possible through this effort: 1LM, 1LS, 1MS, 2LS, 3LS, and 3MM. Across permutations with the utilization of utility-owned assets versus distributed, different land use, and various load cases, the goal through this selection is a range of diverse cases where job impacts might differ by technology and capacity.

[166] Jobs are defined as full-time equivalents (FTEs), or 2,080-hr units of labor (one construction period job equates to one full-time job for 1 year). A part-time or temporary job may be considered one job by other models but would constitute only a fraction of a job according to the JEDI models. In this report, the terms jobs and FTEs are used interchangeably for reader accessibility across languages.

12.2.2 Methodology, Inputs, and Assumptions

12.2.2.1 The Jobs and Economic Development Impact Models

The Jobs and Economic Development Impact (JEDI) models[167] offer the capacity to estimate corresponding gross economic impacts associated with specific project capital and operational investments in the form of jobs, earnings, economic output, and value added (i.e., gross domestic product (GDP)) that are local to the area for the project through input-output analysis. These impacts are generated through the expenditures related to the project contingent amount which the expenditures are spent locally as well as the demand within the local economy. In addition, total project expenditures are also related to the amount of energy capacity that is being installed. Ultimately, the spending associated with the construction, installation, and operation of these renewable electric systems will correspond with varying levels of jobs, earnings, output, and value added. To determine the total effect from these capital investments, JEDI has three separate categories for jobs, which we sum up in terms of total impacts. Such impacts are factored in different JEDI models as follows:

- **Construction and On-Site Labor Impacts:** Refers to the on-site and construction-related effects that are incurred from capital expenditures. This can include jobs immediate to construction, management, transportation of goods, and structural and electrical systems-related jobs.
- **Supply Chain and Related Services Impacts:** Refers to the economic activity and jobs related to the capital investments in the form of payments for goods and services that support the jobs in relation to project development and on-site labor during construction. This can include financing of the project as well as equipment that is used during construction.
- **Induced Impacts:** Refers to the economic impacts driven by the overall spending of household earnings associated with capital expenditures related to both on-site labor and construction-related impacts as well as supply-chain-related impacts. Induced impacts manifest as the economic activity done by households that use earnings from the other separate categories and often relate to retail, accommodation services, and childcare.

Overall, the sum of these categories amounts to the total economic effect that results from the overall capacity installed and its associated capital and operational expenditures that are spent locally. To generate these values from capital investments, multipliers and personal consumption patterns are used to estimate a snapshot of the local economy and demand of goods to derive these overall results. Any changes in expenditures in the development of any renewable technologies will similarly have changed in the overall impacts as estimated through these multipliers. For the context of this analysis, jobs will be reported in total across impacts for all scenarios and by technology.

JEDI results are estimated for two phases: the construction and installation phase and the O&M phase. The former is the cumulation in the number of jobs across the entire period of construction and installation converted into a single year equivalent. These jobs include on-site labor such as establishing foundation and rebar, as well as the transportation of goods and services on-site. Similarly, operation results are during the annual operational life for renewable energy assets invested because of Act 17. JEDI does not assume a set life for the capital

[167] "Jobs and Economic Development Impact Models," NREL, https://www.nrel.gov/analysis/jedi/.

investment nor does it consider the impacts that relate to decommissioning. If investments also are shifted away from the project, JEDI cannot capture these changes.

JEDI economic impact estimates are tailored to specific domestic content percentages based off capital and operational investments for reporting. Estimates in this section reflect certain percentages of how much will be spent locally as it relates to cost categories during construction and installation as well as during O&M. As it relates to wind energy, we assume costs pertaining to the balance of system and equipment will have zero domestic content within Puerto Rico and will be imported into the region. For the construction of the plant such as laying rebar, equipment, transportation, and other development and interconnection related costs,70% will be sourced locally (high labor domestic percentage but zero for equipment and manufacturing). Next, for O&M assumptions on domestic content, we assume personnel are sourced 90% in Puerto Rico and for materials and services are 90% sourced locally. For solar, we assume there is nonzero manufacturing plants for solar however due to the scale of capacity expansion, we assume 2% local content within the region as it relates to materials and equipment, and 70% of labor is sourced locally. Other costs such as permitting and land lease requirements are all 100% sourced locally. For solar O&M, we assume 90% of labor will be sourced within Puerto Rico and 50% for materials and replacement and equipment.

To analyze the lasting jobs and economic impacts associated with O&M, the JEDI model allocates labor income according to IMPLAN, or IMpact Analysis for PLANning, household consumption expenditure patterns. We leveraged IMPLAN 2019 expanded household data for the region of Puerto Rico (IMPLAN 2022).[168] These patterns are a snapshot of the economic demand that reflects the purchasing habits of the average household in Puerto Rico. This spending then relates to the industries that are producing goods and then disseminates the economic impacts associated with the different levels of impact. Generally, higher demand for something such as retail and accommodations would lead to a higher level of jobs into the induced impacts category as compared to the transportation of materials, which would fall into the supply chain and related services impact. To reiterate, JEDI defines jobs in terms of FTE. One full-time equivalent is equal to 2,080 hours, the total amount of hours one full-time worker would do across a fiscal year. For the duration of this section, jobs and FTEs are used interchangeably to support reader accessibility.

12.2.2.1 Interpreting JEDI Terminology

JEDI model results were estimated for both construction and operations for the following economic metrics:

- Jobs: Technically defined as a "full-time equivalent" (FTE). One job (FTE) is a position with a defined set of specific labor hours that can be done by one or more people. For example, one job could be the position of one person working a 40-hr week for an entire year. It can also be two people working full-time for 6 months. Both examples are equivalent to one job.

[168] "2019 US Territories Data Release Notes," IMPLAN, https://support.implan.com/hc/en-us/articles/1260801708010-2019-US-Territories-Data-Release-Notes.

Jobs as they are presented are the sum of direct, indirect, and induced jobs.[169] This definition does not look at workforce implications that are often connotated when talking about jobs.
- Earnings: Any type of income from work, generally an employee's wage or salary and supplemental costs paid by employers, such as health insurance and retirement.
- Output: The total amount of economic activity that occurs within an economy. It is the sum of all expenditures during the process of manufacturing, procurement, and deployment. If a developer purchases a locally manufactured $20,000 residential solar panel that uses a $3,000 inverter that is locally produced the total gross output is $23,000.
- Value added: The total aggregate dollar value of an industry's production to a region. It also includes labor payments, property-type income (including profits), and taxes.

12.2.2.2 Understanding JEDI Estimates

JEDI is an input-output economic impact model that calculates a job in terms of FTEs. JEDI is not a workforce assessment model. JEDI also does not calculate the actual current or future employment in Puerto Rico, nor does it identify workforce development gaps or opportunities.

To provide a more reasonable estimate of job need over time from renewable energy deployment, construction related economic impacts are annualized over deployment periods.[170] Construction job estimates will be averaged across the respective 3- and 5-yr intervals and still compared to the annualized O&M figures. JEDI reports the total full-time equivalents to install and construct clean energy projects over varying time scales. As a reminder, construction jobs are defined as full-time equivalents (FTE), or 2,080-hr units of labor (one construction period job equates to one full-time job for 1 year). JEDI assumes fluctuations for work requirements on a project basis that can make estimates vary between years, and as such, the job and economic impact estimates are divided by the number of years for the data provided.

For O&M, JEDI results are reported on an annual basis; therefore, the jobs reported in the rest of this chapter represent the total long-term jobs to operate and maintain the deployment level of the clean energy projects at the end of the year ranges.

For a further breakdown of definitions for the construction and operation periods see below:

- Construction and Installation: The total jobs per year to meet the deployment capacity in a given time period. For the context of PR100, the total jobs per year examines the inter yearly interval estimates across the entire duration of the project (2023-2050). This results in reporting numbers on an average basis across each interval timespan.
- Operation and Maintenance: The total number of jobs at the end of each deployment period supported to operate and maintain the renewable energy assets. Since these jobs are permanent, we assume their labor hours are still in demand after they are initially deployed. As such O&M jobs are summed across each time period as more energy technologies are deployed until 2050 as a final job estimate supported.

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[169] For the results of this section, direct, indirect, and induced jobs are combined. To review a decomposition of jobs by category please see Appendix I.
[170] Other reports such as *Power Sector, Supply Chain, Jobs, and Emissions Implications of 30 Gigawatts of Offshore Wind Power by 2030* (Lantz et al. 2021) have analyzed job results on an average annual basis across time periods.

12.2.2.3 Act 17 Requirement Expenditures Used for JEDI Analysis

The major capital investments made for the construction, installation, and operation of these renewable assets will necessitate a significant demand of workforce needed for each technology type for every scenario. This section provides estimates for expenditures necessary to estimate the local economic impacts that arise from the transition to renewable technology as Act 17 necessitates. Although many economic factors can influence the estimates from JEDI such as technology type, interconnectedness within local supply chain services in Puerto Rico's economy, geography, and changes to future prices over time, capital and operational expenditures generated through the Engage tool[171] and the Distributed Generation Market Demand Model (dGen) primarily drive the estimates that JEDI supplies.

Figure 359 shows the projected annual expenditures during the construction phase that will be used by JEDI to estimate the economic impacts of this transition to renewable energy. For each scenario, we ran JEDI for six intervals of project study between 2023 and 2050. For each technology type, we estimated the corresponding capital and operational expenditures in their own model. Total economic impact estimates reported highlight combined economic impacts for each scenario. See Appendix I for further decomposition of JEDI estimates for each scenario by technology and interval.

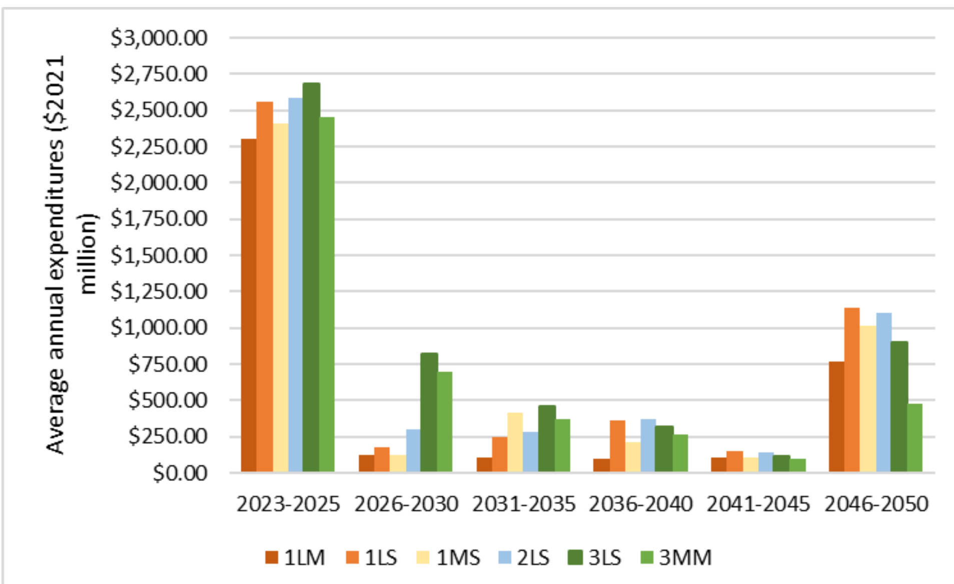


Figure 358. Average Annual Capital Expenditures Across Scenarios, 2023–2050)

Cumulative expenditures were similarly generated for operation and maintenance through PR100 analysis of electric load (Section 7) and capacity expansion modeling (Section 8, page 209) (Figure 360). Cost breakdown structures for distributed solar for residential and nonresidential sectors were not available beyond flat costs. JEDI has cost breakdown structures for both construction and O&M phases for the project and the labor and capital breakdown from JEDI was used to estimate line-item specific costs.

[171] "State, Local, & Tribal Governments: Engage Energy Modeling Tool," NREL, https://www.nrel.gov/state-local-tribal/engage-energy-modeling-tool.html.

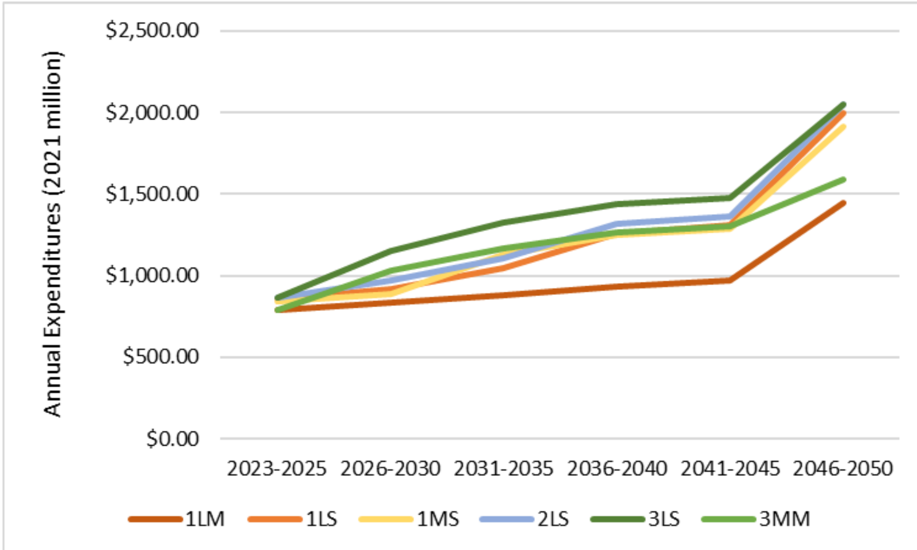


Figure 359. Average annual O&M expenditures across scenarios, 2023–2050

12.2.3 Results

12.2.3.1 Impacts Across Scenarios

Across all scenarios, each scenario supports an average of 2,482 jobs due to construction and installation of renewable energy, $122 million in total earnings, $209 million in economic output, and $145 million in value added on average from 2023 to 2050 (Table 45). These estimates see high peaks during 2023–2025 and during 2046–2050 with lower points between. On average these workers earned $49,288 annually across all sectors within the construction phase. Common between all scenarios is the initial ramp-up of jobs beginning during 2023–2025 and substantially dipping until the last interval in 2046–2050. This ramp-up is required to meet the 2025 40% requirements set forth in Act 17 and the total number of jobs in the inter-intervals drop down as capital investments made to utility-scale solar pulls back until the end of this analysis in 2050.

Table 45. Total Economic Impacts During Construction and Installation Across All Scenarios, 2023–2050

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Total
Total jobs	7,936	1,557	1,202	1,001	468	2,728	14,892
Earnings ($ million 2021)	$390	$80	$60	$50	$24	$131	$734
Average earnings per worker	$49,143	$51,381	$49,917	$49,950	$51,282	$48,021	$49,288
Output ($ million 2021)	$663	$133	$103	$86	$40	$229	$1,254
Value added ($ million 2021)	$460	$89	$71	$59	$27	$163	$869

Although trends in employment differ slightly by scenario over time and magnitude, 3LS and 3MM see a lesser decrease between 2026 and 2035 because of the deployment of distributed solar across Puerto Rico while Scenario 1 variants increase near the end because of the deployment of utility-scale solar energy (Figure 361).

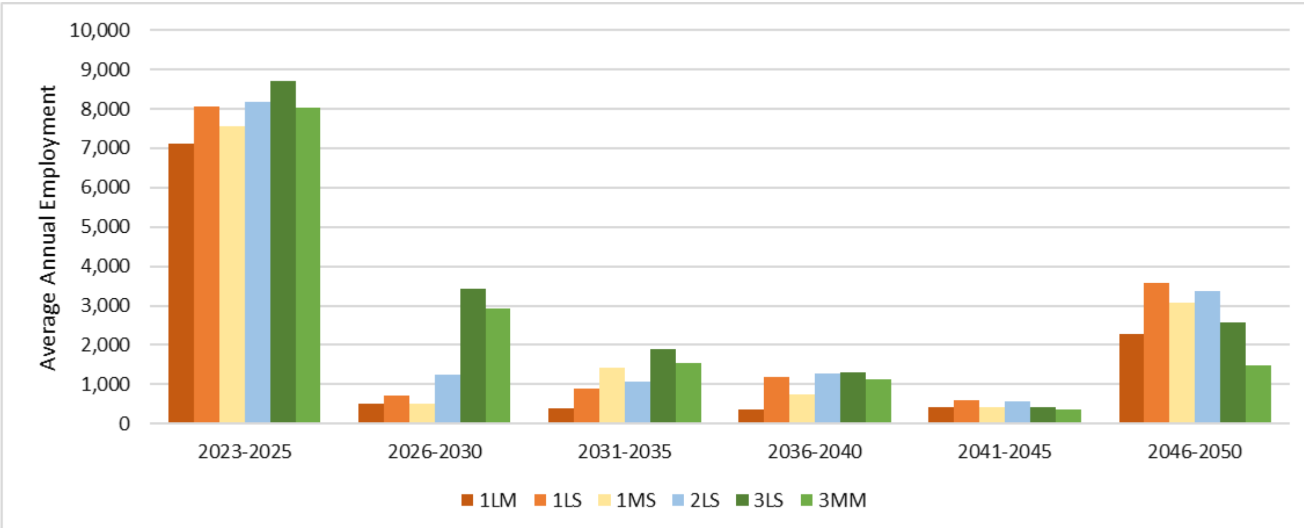


Figure 360. Average annual employment during construction and installation by scenario, 2023–2050

Across all scenarios, the total number of jobs supported annually during O&M is 281 initially in 2023–2025 and increases to a total of 537 jobs by 2050 on average, with an annual average of 386 job FTEs. The average earnings per worker are $41,450 annually across all occupations. Economic activity spurred by the O&M of these technologies supports an average of $25 million on average annually in value added and $35 million economic output between interindustry spending supporting the O&M of this scenario's electric grid assets.

Table 46. Across All Scenarios Overall Average Economic Impacts During O&M, 2023–2050 ($2021 dollars)

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Average annually
Jobs	281	324	363	398	413	537	386
Earnings ($ million 2021)	$12	$13	$15	$16	$17	$22	$16
Output ($ million 2021)	$25	$27	$32	$36	$37	$51	$35
Value added ($ million 2021)	$17	$19	$23	$26	$26	$37	$25

During the O&M phase, 3LS continues to support the highest number of jobs as renewable energy is deployed into Puerto Rico's electric grid. Following the trends during construction and operation, because more expenditures were made in 3LS, its trend continually has the most capacity for jobs supported from 2023 to 2050 with a total annual employment value of 2,500. (Figure 362).

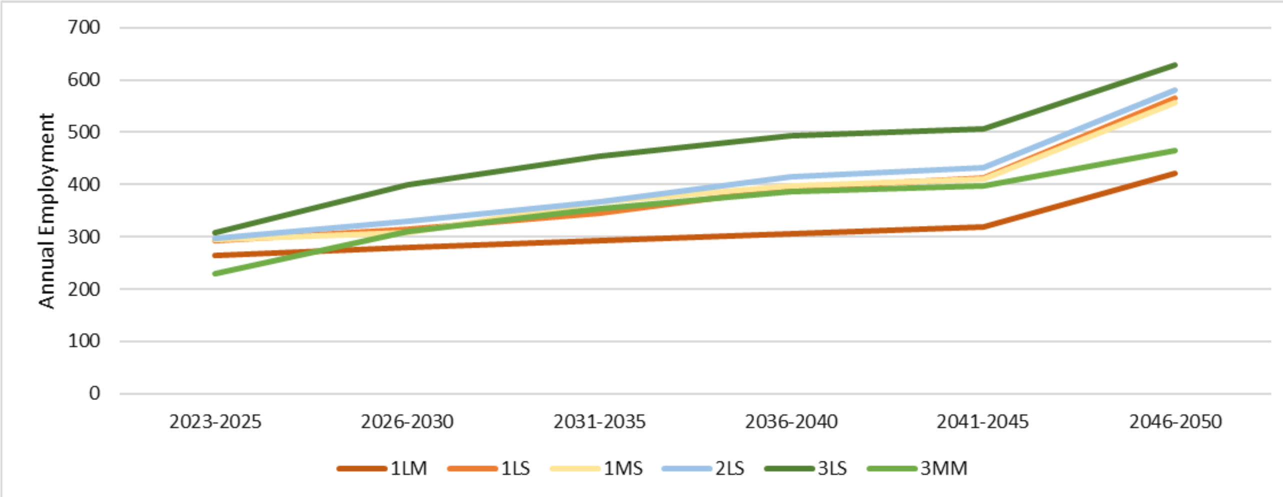


Figure 361. Average annual employment during O&M by scenario, 2023–2050

12.2.3.2 1LM Scenario

Between 2023 and 2050, the selected scenario variation 1LM supports a total capacity of 11,090 jobs from capital investments in renewable energy technology. Across the $545 million in earnings total, workers supporting the total job capacity during the construction phase earn on average $49,143 annually across sectors and occupations (Table 47). In addition, these capital investments spur economic activity and support $644 million in annual value added on average and $927 million between industries spending money to support the construction and maintenance of all the renewable energy assets invested. A significant share of the local economic impacts incurred during construction and installation occurs during the first period from 2023 to 2025 because of the investments specific to utility-scale PV. Investments made between 2026 through 2045 are smaller in comparison as investments in land-based wind and distributed solar continue to be installed, but not utility-scale PV.

Table 47. 1LM: Total Economic Impacts During Construction and Installation, 2023–2050

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Total
Total jobs	7,125	509	391	374	428	2,264	11,090
Earnings ($ million 2021)	$350	$26	$19	$18	$22	$110	$545
Average earnings per worker	$49,123	$51,081	$48,593	$48,128	$51,402	$48,587	$49,143
Output ($ million 2021)	$593	$44	$34	$32	$37	$188	$927
Value added ($ million 2021)	$413	$29	$23	$22	$24	$133	$644

For 2023–2025 and 2046–2050, utility-scale solar energy supports a significant proportion of over 50% for the total average annual employment in those intervals with 3,708 and 1,317 jobs respectively for a grand total of 5,026 jobs supported. Residential solar supports the second most capacity of jobs needed during the construction phase. During 2023–2025 residential solar accounts for 2,547 jobs, in 2026–2030 435 additional jobs are needed, 224 jobs are supported during 2031–2035, 186 jobs during 2036–2040, 353 jobs during 2041–2045, and lastly during 2046–2050 a final 472 jobs are supported during construction. Land-based wind is the third proportionally highest technology supporting the most jobs. During 2023–2025 onshore wind accounts for 506 jobs. When capital investments are incurred and construction begins during 2031–2040 on average an additional 140 jobs are supported annually, and during the last period where wind is deployed a final 369 jobs are supported for a total of 1,154 jobs. Lastly nonresidential solar supports 363 jobs during 2023–2025, 74 jobs additional jobs during 2026–2030, 36 jobs during 2031–2035, 39 jobs during 2036–2040, 75 jobs during 2041–2045, and 106 jobs during 2046–2050 (Figure 363).

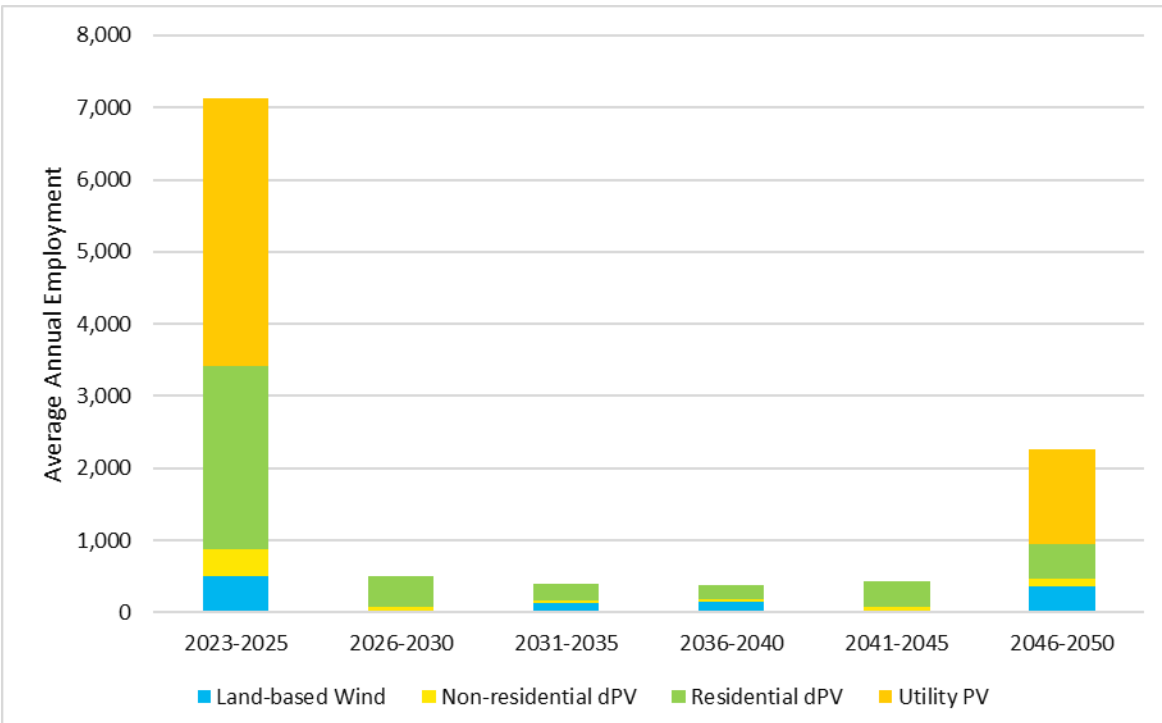


Figure 362. 1LM: Average annual employment during construction and installation by technology, 2023–2050

On average, the total number of jobs annually supported to operate and maintain the capital investments made to the electric grid increases from 265 in 2023 to 422 by 2050, with an annual average of 314 jobs from 2023 to 2050. The average earnings per worker are $41,401 annually across all occupations. Economic activity spurred by the O&M of these technologies supports an average of $18 million annually in value added and $27 million economic output between interindustry spending supporting the maintenance of these electrical assets.

Table 48. 1LM: Average Economic Impacts During O&M, 2023–2050

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Average annually
Jobs	265	279	292	305	319	422	314
Earnings ($ million)	$11	$11	$12	$13	$13	$17	$13
Earnings per worker	$41,509	$39,426	$41,096	$42,622	$40,752	$40,284	$41,401
Output ($ million)	$23	$24	$25	$27	$27	$38	$27
Value added ($ million)	$15	$16	$17	$18	$19	$25	$18

Across 2023–2050 for 1LM, utility-scale solar supports the most jobs, accounting for more than half of all employment. From 2023 to 2045, utility-scale solar initially supports 150 jobs and steadily maintains that number of workers whereas residential rooftop solar grows because of installation over time. From 2046 to 2050, utility solar sees growth in the number of jobs needed to operate and maintain these electrical assets to over 230 jobs because of the investments made during this time. Nonresidential solar supports 10 jobs initially and grows more slowly than residential and utility solar to a maximum capacity of 30 jobs. Lastly, land-based wind follows a similar pattern to nonresidential solar and initially supports 30 O&M jobs and by 2050 supports 50 jobs.

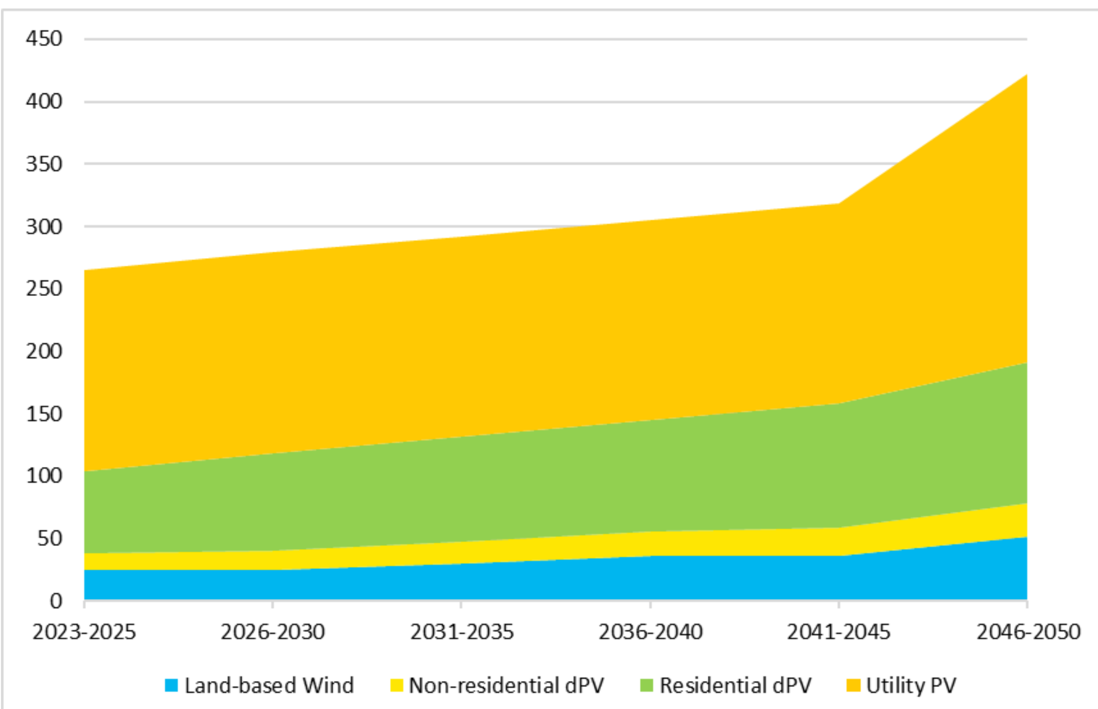


Figure 363. 1LM: Annual employment during O&M by technology, 2023–2050

12.2.3.3 1LS Scenario

Between 2023 and 2050, 1LS supports a total capacity of 14,986 jobs from capital investments in renewable energy technology, as shown in Table 49. Across the $734 million in earnings in total, workers supporting the total job capacity during the construction phase earn on average $48,979 annually across sectors and occupations. In addition, these capital investments support $879 million in value added and $1.26 billion in economic output from interindustry spending of dollars to support the construction phase of all the renewable energy assets installed. Like 1LM, a significant share of the local economic impacts is incurred during construction and installation in 2023–2025 and 2046–2050 because of the investments specific to utility-scale PV in those intervals. Investments made between 2026 and 2045 are smaller in comparison as investments in land-based wind and distributed solar continue to be installed, but not investments in utility-scale PV.

Table 49. 1LS: Total Economic Impacts During Construction and Installation, 2023–2050

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Total
Total jobs	8,048	714	878	1,179	598	3,568	14,986
Earnings ($ million 2021)	$396	$36	$43	$57	$31	$172	$734
Average earnings per worker	$49,205	$50,420	$48,975	$48,346	$51,839	$48,206	$48,979
Output ($ million 2021)	$671	$61	$76	$100	$51	$301	$1,260
Value added ($ million 2021)	$466	$41	$53	$71	$34	$214	$879

Compared to 1LM, utility-installed solar accounts for most jobs needed to support the construction phase during 2023–2025. To contrast 1LM, during 2036– 2040, utility-scale PV has approximately 300 of the 1,000 total jobs supported and only 1,000 jobs in the last interval of 2046–2050. Second to utility solar, residential distributed solar supports 3,000 jobs during 2023–2025. Between 2026 and 2045, residential solar sees additional capacity added each interval with 2026–2030 and 2041–2046 supporting proportionally the most jobs. Lastly, land-based wind sees a higher capacity of jobs needed compared to 1LM. Land-based wind sees around 500 jobs supported during 2023–2026 and 2031–2040 in each respective interval. Lastly, wind energy sees its highest capacity of jobs supported during 2046–2050 with around 1,500 additional jobs, trading off with utility-scale solar.

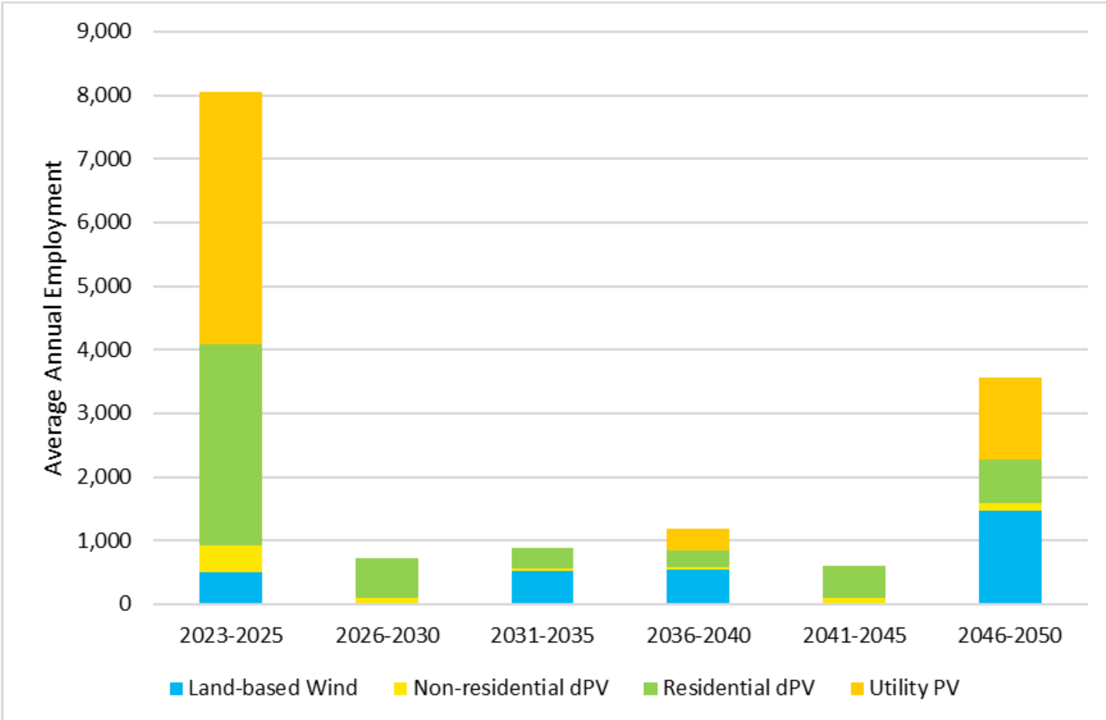


Figure 364. 1LS: Average annual employment during construction and installation by technology, 2023–2050

On average, the total number of jobs annually supported to operate and maintain the capital investments made to the electric grid increases from 265 in 2023 to 422 by 2050, with an annual average of 314 from 2023 to 2050 (see Table 50). The average earnings per worker are $41,343 annually across all occupations. Economic activity spurred by the O&M of these technologies supports an average of $18 million annually in value added and $27 million economic output between interindustry spending supporting the maintenance of these electrical assets.

Table 50. 1LS: Average Economic Impacts During O&M, 2023–2050

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Average annually
Jobs	294	314	346	393	412	565	387
Earnings ($ million 2021)	$12	$13	$14	$16	$17	$23	$16
Earnings per worker	$40,816	$41,401	$40,462	$40,712	$41,262	$40,708	$41,344
Output ($ million 2021)	$25	$26	$31	$37	$38	$58	$36
Value added ($ million 2021)	$16	$17	$21	$26	$27	$42	$25

Across 2023–2050 for 1LS, utility-scale solar supports the most jobs, accounting for just under half of all employment needed to operate and maintain the investments made to transition to a renewable electric grid. From 2023 to 2045, utility-scale solar initially supports around 170 jobs and steadily increases that capacity of jobs needed to 225 jobs. Residential rooftop solar similarly as additional capacity is added over time supporting 80 jobs in 2025 to 150 jobs by 2050. Nonresidential solar supports 15 jobs initially and incrementally gains more to a maximum capacity of 30 jobs needed. Lastly, land-based wind has capacity to operate from 2023 to 2025 with 25 jobs and increases to a maximum of 130 jobs.

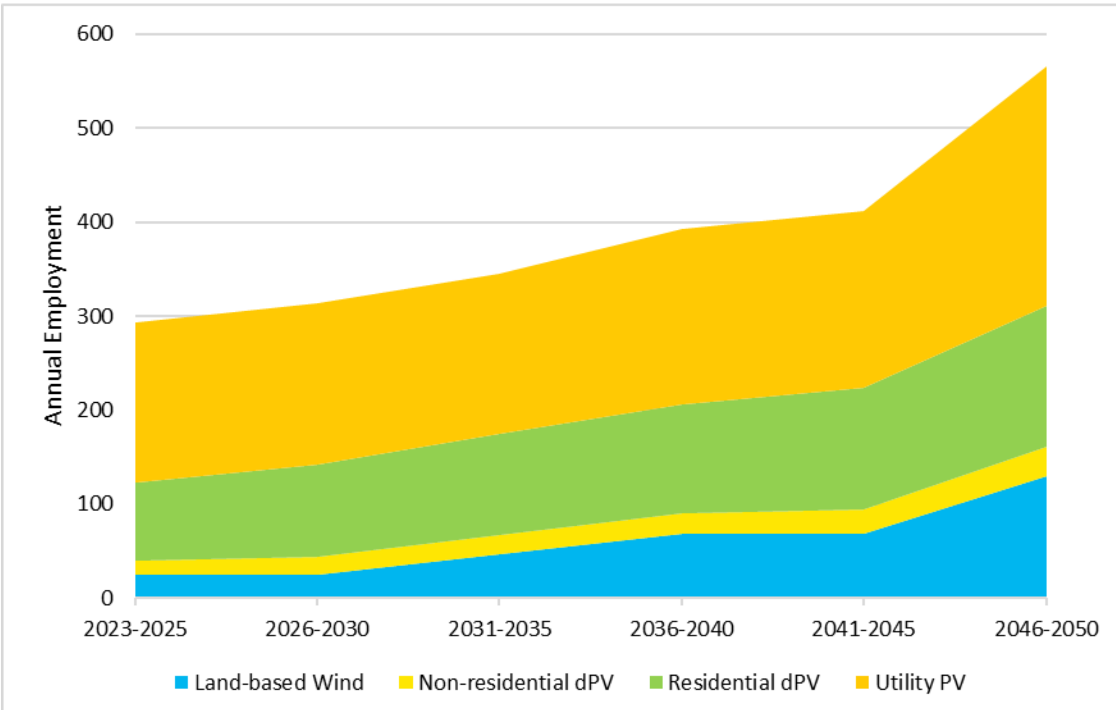


Figure 365. 1LS: Annual employment during O&M by technology, 2023–2050

12.2.3.4 1MS Scenario

Next, across the duration of this transition to a renewable electric grid, 1MS supports on average 2,291 jobs annually from capital investments in renewable energy technology. Across the $669 million in earnings total across all years of construction efforts, workers during the construction phase earn on average $48,669 annually across sectors and occupations. In addition, these capital investments support a total of $814 million in value added and $1.16 billion in economic output from interindustry spending of dollars to support the construction phase of all the renewable energy assets installed.

Table 51. 1MS: Total Economic Impacts During Construction and Installation, 2023–2050

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Total
Total jobs	7,555	509	1,429	741	428	3,084	13,746
Earnings ($ million 2021)	$370	$26	$68	$36	$22	$148	$669
Average earnings per worker	$48,974	$51,081	$47,586	$48,583	$51,402	$47,990	$48,669
Output ($ million 2021)	$632	$44	$124	$64	$37	$259	$1,159
Value added ($ million 2021)	$441	$29	$89	$46	$24	$185	$814

Utility-scale solar accounts for most jobs needed to support the construction phase during 2023–2025 and 2046–2050, supporting 3,465 and 1,331 jobs, respectively, per interval on average annually with no jobs added between 2026 and 2045 because no additional capacity is added during these periods. For land-based wind, we see that across Scenario 1 variation with a high adoption of utility-scale renewable assets across technologies, the most capacity added supports more jobs for land-based wind proportionally with 1,179 jobs on average annually between 2023 and 2025, 1,169 jobs added during 2031–2035, 515 jobs during 2036–2040, and lastly 1,176 jobs added in 2050. With more land available compared to the Less Land variations, more deployment of land-based wind is present in 1MS; with higher expenditures spent on land-based wind, this translates to more jobs specific to land-based wind. This trade-off occurs mostly with residential PV proportionally. For residential solar, 2,547 jobs are initially supported during 2023–2025, and between 2031 and 2040 residential solar has marginally fewer jobs at 435, 224, and 186 jobs, respectively, for each interval. Lastly, residential solar supports on average 472 jobs annually at the end during 2046–2050. Nonresidential solar supports the highest share of jobs during 2023–2025 with 363 jobs on average annually. Between the inner intervals of deployment for nonresidential solar, each year on average supports an annual 56 jobs and boosts to 106 jobs at the end during 2046–2050 for a total of 693 jobs.

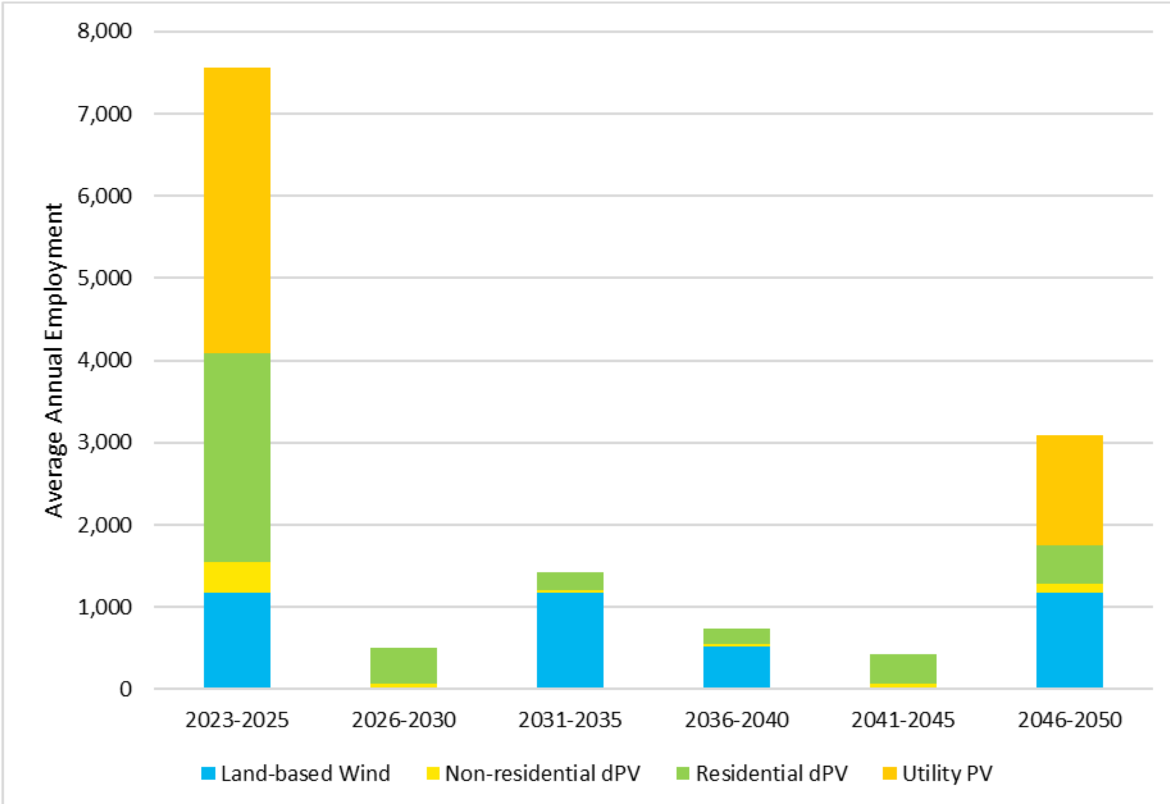


Figure 366. 1MS: Average annual employment during construction and installation by technology, 2023–2050

On average, the total number of jobs annually is 294 in 2023 and increases to a total of 566 by 2050 on average, with an annual average of 389 jobs from 2023 to 2050. The average earnings per worker are $41,131 annually across all occupations. Economic activity spurred by the O&M of these technologies supports an average of $31 million on average annually in value added and $42 million economic output between interindustry spending supporting the O&M of this scenario's electric grid assets.

Table 52. 1MS: Average Economic Impacts During O&M, 2023–2050

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Average annually
jobs	294	309	368	398	411	556	389
Earnings ($ million 2021)	$12	$13	$15	$17	$17	$23	$16
Earnings per worker	$40,816	$42,071	$40,761	$42,714	$41,363	$41,367	$41,131
Output ($ million 2021)	$29	$30	$40	$45	$46	$63	$42
Value added ($ million 2021)	$20	$21	$30	$34	$34	$47	$31

Like other Scenario 1 variants, approximately half of all employment needed to operate and maintain the renewable energy assets are through utility-scale PV during 2023–2025, supporting 152 jobs. Because no additional capital investments are made between 2026 and 2045, utility solar sees an increase of an additional 74 jobs bringing a cumulative annual total of O&M jobs to 226 to support the O&M of utility solar panels. For residential solar, an initial 66 annual jobs on average are supported during 2023–2025 with approximately 8 jobs on average added annually between the middle intervals of 2026–2045 and with 14 jobs added at the end annually between 2046 and 2050. Following a similar trend for when capital investments are made for land-based wind within 1MS, jobs are supported for the O&M of wind energy when these costs are incurred. Initially in 2023–2025, land-based wind supports a total of 63 jobs annually. As more land-based wind capacity is installed during 2031–2035, 2036–2040, and 2046–2050, the total jobs added for each interval is 52, 23, and 52, respectively, for a total of 190 jobs. Nonresidential solar, although smaller than other technologies, sees an initial 13 jobs supported and incrementally grows between 2026 and 2045 with an average of 2 jobs. Lastly, over 2046–2050, nonresidential solar sees an additional 5 jobs for a cumulative 27 jobs on average.

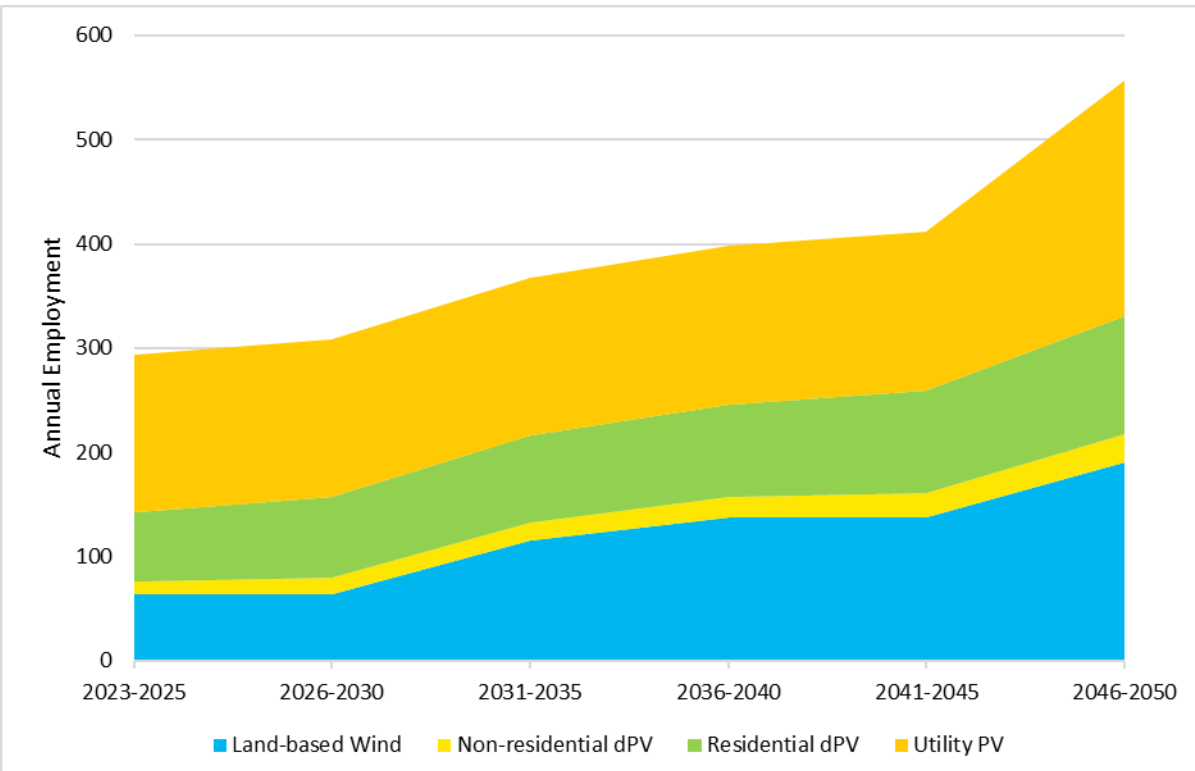


Figure 367. 1MS: Annual employment during O&M by technology, 2023–2050

12.2.3.5 2LS Scenario

2LS acts a scenario that has some relative trade-offs between utility-scale deployment with distributed renewable energy deployment. Unlike scenario 3 variants, it has more utility deployment but still utilizes more distributed resources than scenario 1 variants. 2LS supports a total of 15,698 jobs across all intervals of construction efforts due to capital investments in renewable energy technology. Across the average earnings of $772 million from 2023 to 2050, workers supporting the construction and installation of renewable energy during the construction phase earn on average $49,178 annually across sectors and occupations. Additionally, these capital investments spur economic activity and support in total $772 million in value added and $1.3 billion between industries spending money to support the construction and maintenance of all the renewable energy assets invested.

Table 53. 2LS: Total Economic Impacts During Construction and Installation, 2023–2050

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Total
Total jobs	8,171	1,241	1,070	1,281	554	3,381	15,698
Earnings ($ million 2021)	$402	$63	$53	$62	$28	$163	$772
Earnings per worker	$49,198	$50,766	$49,533	$48,400	$50,542	$48,211	$49,178
Output ($ million 2021)	$681	$106	$92	$110	$47	$284	$1,321
Value added ($ million 2021)	$472	$71	$64	$77	$32	$202	$918

As with previous cases, utility-installed solar accounts for most jobs needed to support the construction phase during 2023–2025 and 2046–2050 supporting 3,918 and 1,437 jobs respectively. The only other time capital investments are made for the construction and installation for utility PV occurs between 2036–2040, supporting 187 jobs for the additional capacity added then. For land-based wind, a trade-off for less utility-scale assets and with less land as its variation, land-based wind initially supports 507 jobs. Additional capacity is installed between 2031 and 2040 and on average 517 jobs are added annually during these intervals. Lastly, during 2046–2050 onshore wind supports an additional 1,239 jobs. This trade-off occurs mostly with residential PV proportionally early on during 2023–2025 where it had an additional 3,322 jobs supported annually in this interval on average. 2026–2030 is where residential solar had its second highest number of jobs needed at 1,153s on average. Between 2031–2040 an additional 521 jobs were added on average. For the last period of 2046–2050, the construction of residential solar rooftops supports an additional 579 jobs. Nonresidential solar proportionally adds the most jobs early on during 2023–2025 supporting a total of 424 jobs total, and between 2026–2050 it supports on average a total of 648 jobs needed to construction and install industrial and commercial rooftop solar panels.

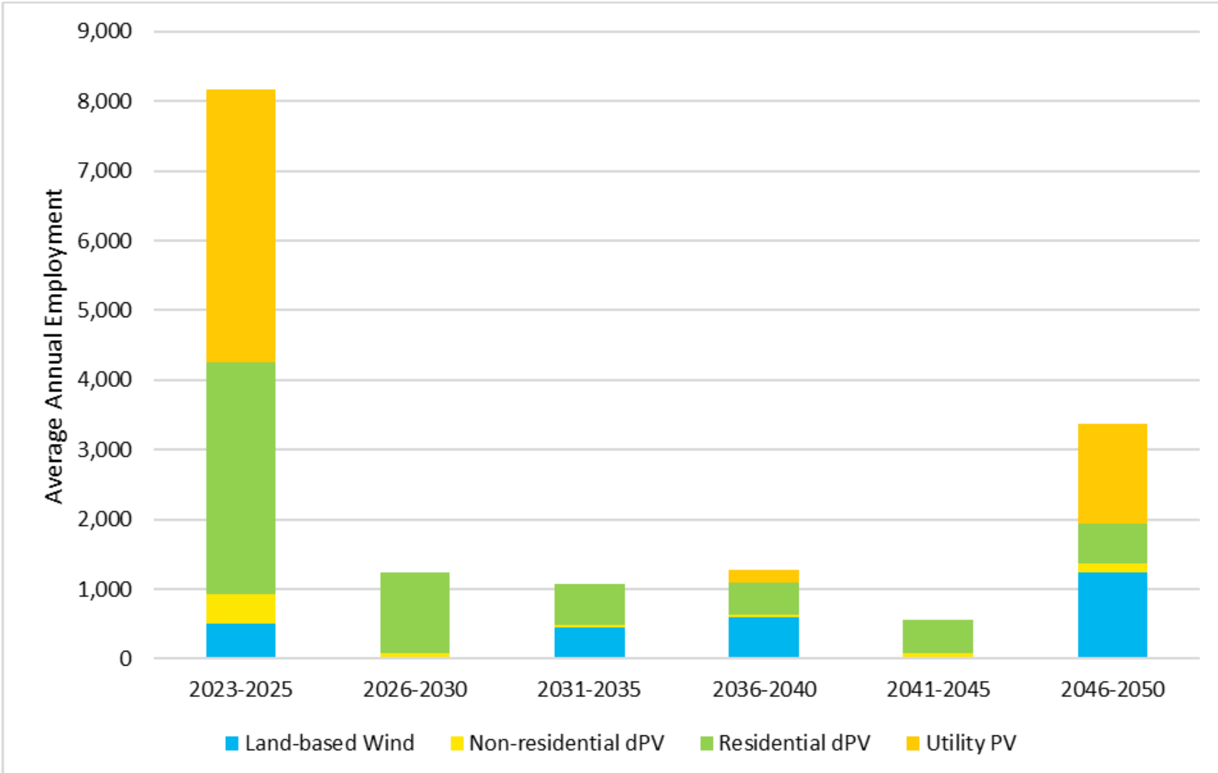


Figure 368. 2LS: Average annual employment during construction and installation by technology, 2023–2050

On average, the total number of jobs annually supported is 296 between 2023 and 2025 and increases to a total of 581 by 2050 on average, with an annual average of 403 jobs from the start to end of the analysis. The average earnings per worker are $39,702 annually across all occupations. Economic activity spurred by the O&M of these technologies supports an average of $25 million annually in value added and $36 million economic output between interindustry spending supporting the O&M of these electrical assets.

Table 54. 2LS: Average Economic Impacts During O&M, 2023–2050

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Average
Total jobs	296	330	366	415	432	581	403
Earnings ($ million 2021)	$12	$13	$15	$17	$18	$24	$16
Earnings per worker	$40,541	$39,394	$40,984	$40,964	$41,667	$41,308	$39,702
Output ($ million 2021)	$25	$27	$31	$38	$39	$57	$36
Value added ($ million 2021)	$16	$18	$22	$27	$28	$41	$25

Initially, utility-scale PV supports a total of 170 jobs on average. As more capital expenditures are made and more solar energy is installed during 2046–2040 and 2046–2050, an additional 9 and 75 jobs are supported, respectively, for a total annual employment of 254 jobs on average needed to operate and maintain utility-scale solar panels. Residential solar initially supports the second-highest number of jobs at 86. Across the middle and later intervals, the number of additional jobs supported continually decreases proportionally such that in 2026–2030 an additional 31 jobs were added, and between the middle and end intervals of 2031–2050 an average of 15 jobs were added annually. Land-based wind follows a similar pattern for the deployment of capacity added to utility-scale PV, where more turbines were added during the intervals of 2023–2025, 2031–2035, and 2046–2050. In the initial period, a total of 25 jobs were added. During 2031–2035, 18 jobs were added, and during 2036–2040, a total of 24 jobs were supported. Lastly, for land-based wind, between 2046 and 2050, 52 jobs were added to support the last deployment of wind energy for a total of 119 jobs supported for wind. Nonresidential solar, although smaller than other technologies, has an incremental gain of jobs added from 2023 to 2050. Initially during the first interval, nonresidential solar supports 15 jobs. For all other intervals, the additional capacity supports an average of 3 jobs from 2026 to 2050 for a total of 31 jobs for the O&M of nonresidential solar panels.

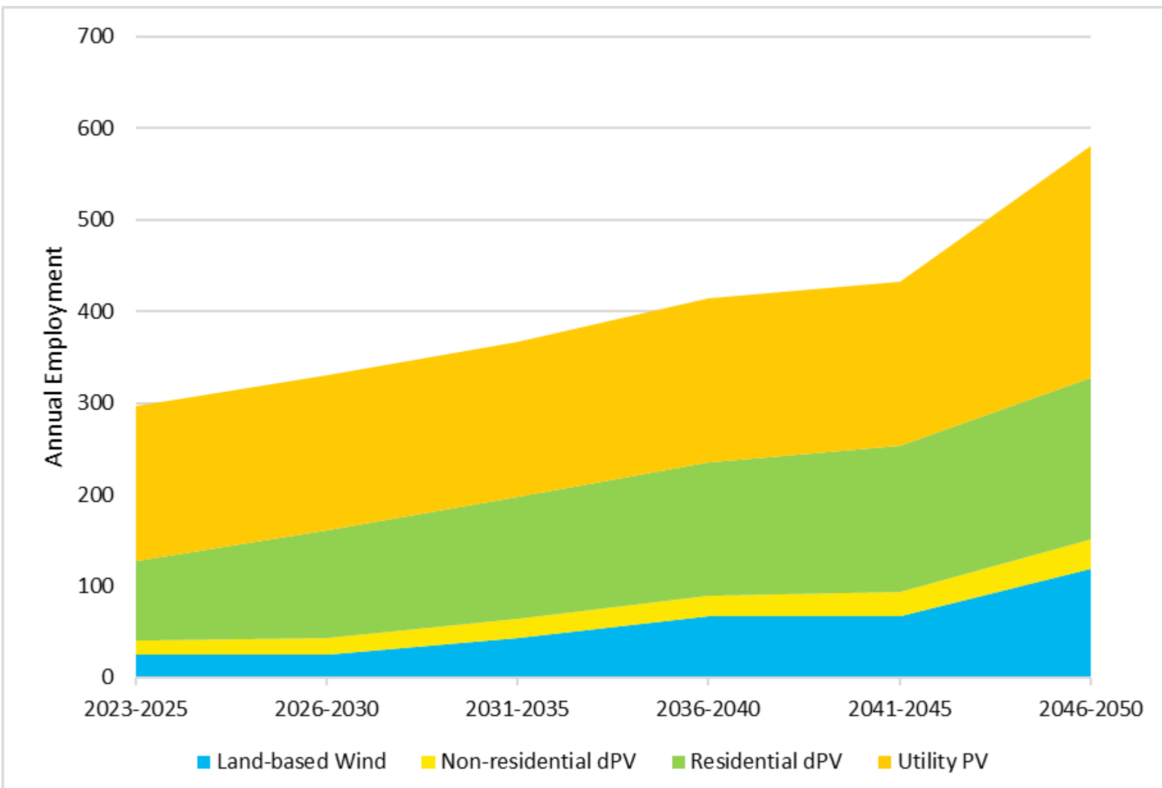


Figure 369. 2LS: Annual employment during O&M by technology, 2023–2050

12.2.3.6 3LS Scenario

3LS is the scenario variant with the highest adoption of distributed renewables with less land use available for utility-scale deployment. 3LS supports a total of 18,358 jobs in its capacity across all years of construction and installation efforts. Across the total earnings of $915 million from 2023 to 2050, workers supporting the construction and installation of renewable energy during the construction phase earn on average $49,842 annually across sectors and occupations. In addition, these capital investments spur economic activity and support $1 billion in value added on average and $1.5 billion between industries spending money to support the construction and maintenance of all the renewable energy assets invested.

Table 55. 3LS: Total Economic Impacts During Construction and Installation, 2023–2050

Construction Phase	**2023–2025**	**2026–2030**	**2031–2035**	**2036–2040**	**2041–2045**	**2046–2050**	**Total**
Total jobs	8,694	3,438	1,900	1,312	429	2,585	18,358
Earnings ($ million 2021)	$430	$176	$97	$67	$22	$124	$915
Earnings per worker	$49,459	$51,193	$51,053	$51,067	$51,282	$47,969	$49,842
Output ($ million 2021)	$727	$294	$163	$112	$37	$215	$1,548
Value added ($ million 2021)	$502	$196	$109	$75	$25	$153	$1,060

Across all technologies, residential solar accounts for the most employment supported during the construction period with 3,937 jobs on average during 2023–2025. This trend continues nearly to the end from 2026 to 2045. For each interval, the deployment of more residential solar corresponds with an additional 3,309 jobs during 2026–2030, 1,694 jobs from 2031 to 2035, and 1,243 jobs from 2036 to 2040; during 2041–2045, residential solar supports 298 jobs; lastly, during 2046–2050, it supports 181 jobs. Second to residential solar, utility-scale solar supports the second-most employment during 2023–2025 and the most during 2046–2050 when further capital expenditures are spent to support the construction of more utility-scale solar electrical systems. In the first period (2023–2025), utility-scale PV supports 3,600 jobs and during 2046–2050, an additional 1,500 jobs are supported. For land-based wind, capital expenditures occur during 2023–2025, 2031–2035, and at the end, in 2046–2050, where jobs during construction are supported. Initially, during 2023–2025, the deployment of wind energy supports 25 jobs, an additional 6 jobs during the 2035 interval, and 30 jobs during 2046–2050. Lastly, nonresidential PV supports proportionally its most at a total of 630 jobs during 2023–2025 with minor additions added as more capacity is installed across the rest of all other intervals. Between 2026 and 2050, an additional five jobs on average are added annually to support the construction of industrial solar panels.

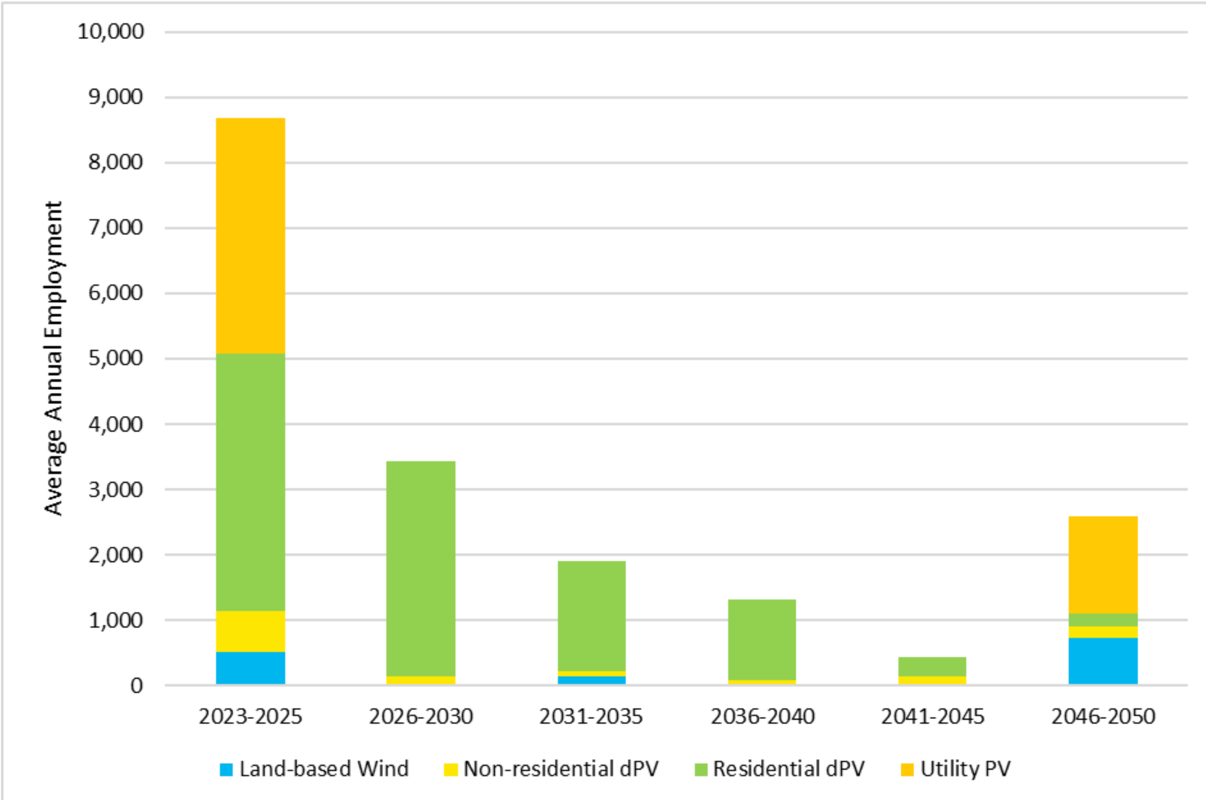


Figure 370. 3LS: Average annual employment during construction and installation by technology, 2023–2050

On average, the total number of jobs annually supported is 307 between 2023 and 2025 and increases to a total of 629 by 2050 on average, with an annual average of 465 jobs from the start to end of the analysis. The average earnings per worker are $38,710 annually across all occupations. Economic activity spurred by the O&M of these technologies supports an average of $25 million annually in value added and $35 million economic output between interindustry spending supporting the O&M of these electrical assets.

Table 56. 3LS: Average Economic Impacts During O&M, 2023–2050

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Average annually
Jobs	307	400	455	493	507	629	465
Earnings ($ million 2021)	$12	$16	$18	$19	$20	$25	$18
Earnings per worker	$39,088	$40,000	$39,560	$38,540	$39,447	$39,746	$38,710
Output ($ million 2021)	$25	$30	$34	$36	$37	$50	$35
Value added ($ million 2021)	$17	$21	$24	$26	$26	$36	$25

Initially, utility-scale PV supports a total of 157 jobs on average. As more capital expenditures are made and more utility-based solar energy is installed in 2046–2050, an additional 79 jobs are supported for a total annual employment of 236 jobs on average needed to operate and maintain utility-scale solar panels. Residential solar initially supports the second-highest number of jobs at 102. The number of jobs supported through residential solar continually decreases proportionally: In 2026–2030, an additional 88 jobs were added; between 2031 and 2040, an average of 41 jobs were added annually; lastly, between 2041 and 2050, an average of 7 jobs were added for a total of 286 jobs across the entire analysis. Land-based wind follows a similar pattern for the deployment of capacity added to utility-scale PV, where more turbines were added during the intervals of 2023–2025, 2031–2035, and 2046–2050. In the initial period, a total of 102 jobs were added. During 2031–2035, an additional 6 jobs were added; lastly, between 2046 and 2050, 30 jobs were added to support the last deployment of wind energy for a total of 61 jobs supported for wind. Nonresidential solar, although smaller than other technologies, has an incremental gain of jobs added from 2023 to 2050. Initially during the first interval of 2023–2025, nonresidential solar supports 23 jobs. For all other intervals, the additional capacity added supports an average of 5 jobs from 2026 to 2050 for a total of 47 jobs for the O&M of nonresidential solar panels.

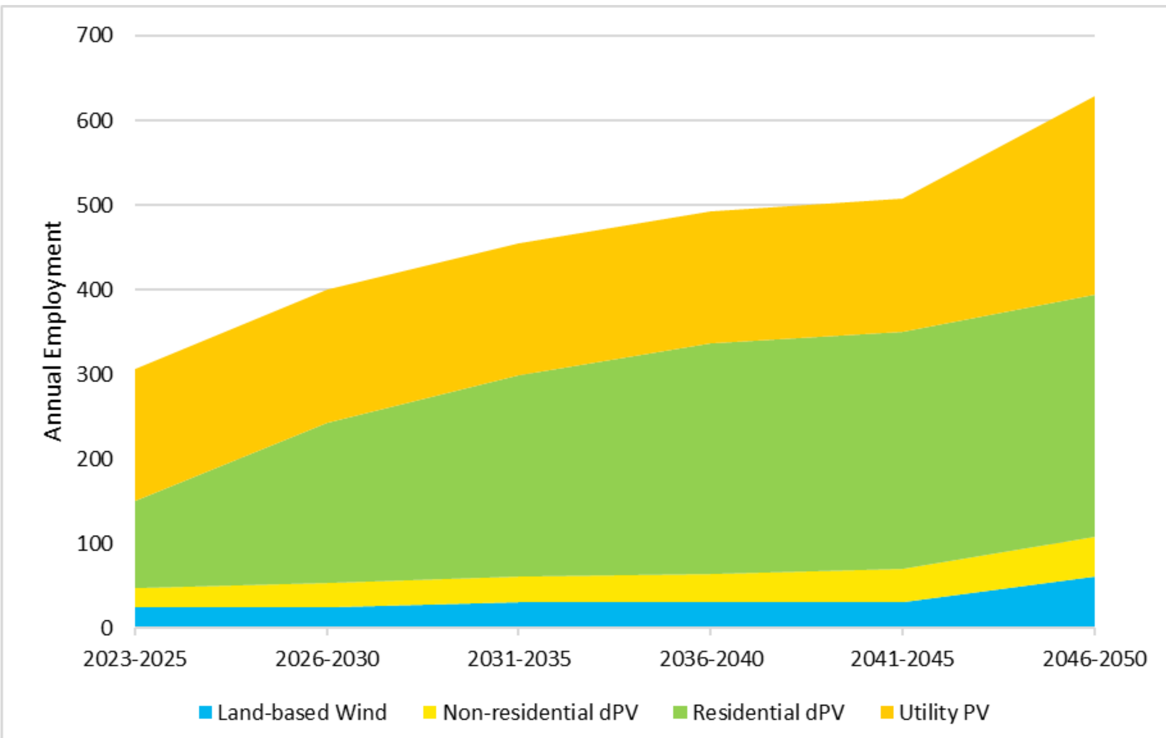


Figure 371. 3LS: Annual employment during O&M by technology, 2023–2050

12.2.3.7 3MM Scenario

The last scenario, 3MM, which uses more rooftop solar than Scenario 1 or Scenario 2 with more land and compensation, supports on average 2,579 jobs annually from capital investments for solar and wind energy. Across the $129 million in earnings total on average, workers supporting the total job capacity during the construction phase earn on average $50,019 annually across sectors and occupations. In addition, these capital investments spur economic activity and support $150 million in annual value added on average and $218 million between industries spending money to support the construction and maintenance of all the renewable energy assets invested. A significant share of the local economic impacts incurred during construction and installation occurs between 2023 and 2030 because of the investments specific to distributed solar for residential and nonresidential customers.

Table 57. 3MM: Total Economic Impacts During Construction and Installation, 2023–2050

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Total
Total jobs	8,023	2,931	1,544	1,120	371	1,484	15,472
Earnings ($ million 2021)	$395	$150	$79	$57	$19	$71	$771
Earnings per worker	$49,233	$51,177	$51,166	$50,893	$51,213	$47,844	$49,832
Output ($ million 2021)	$674	$251	$132	$96	$32	$126	$1,311
Value added ($ million 2021)	$468	$167	$88	$64	$21	$90	$898

Utility-scale solar accounts for most jobs needed to support the construction phase during 2023–2025 and 2046–2050, supporting 3,900 and 1,400 jobs, respectively. The only other time capital investments are made for the construction and installation for utility-scale PV occurs between 2036 and 2040, supporting just under 200 jobs for the capacity added then. For land-based wind, with a trade-off for fewer utility-scale assets and less land as its variation, land-based wind initially supports 500 jobs. Additional capacity is installed between 2031 and 2040 and on average 500 jobs are added annually during these intervals. Lastly, during 2046–2050, land-based wind supports an additional 1,200 jobs. This trade-off occurs mostly with residential PV proportionally early on during 2023–2025 where it had an additional 3,300 jobs supported annually in this interval on average. The period 2026–2030 is when residential solar had its second-highest number of jobs needed at 1,150 on average. Between 2031 and 2040, an additional 500 jobs were added on average. Nonresidential solar proportionally adds the most jobs early on during 2023–2025, supporting a total of 400 jobs, and between 2026 and 2050 it supports on average a total of 80 jobs needed to construct and install industrial and commercial rooftop solar panels.

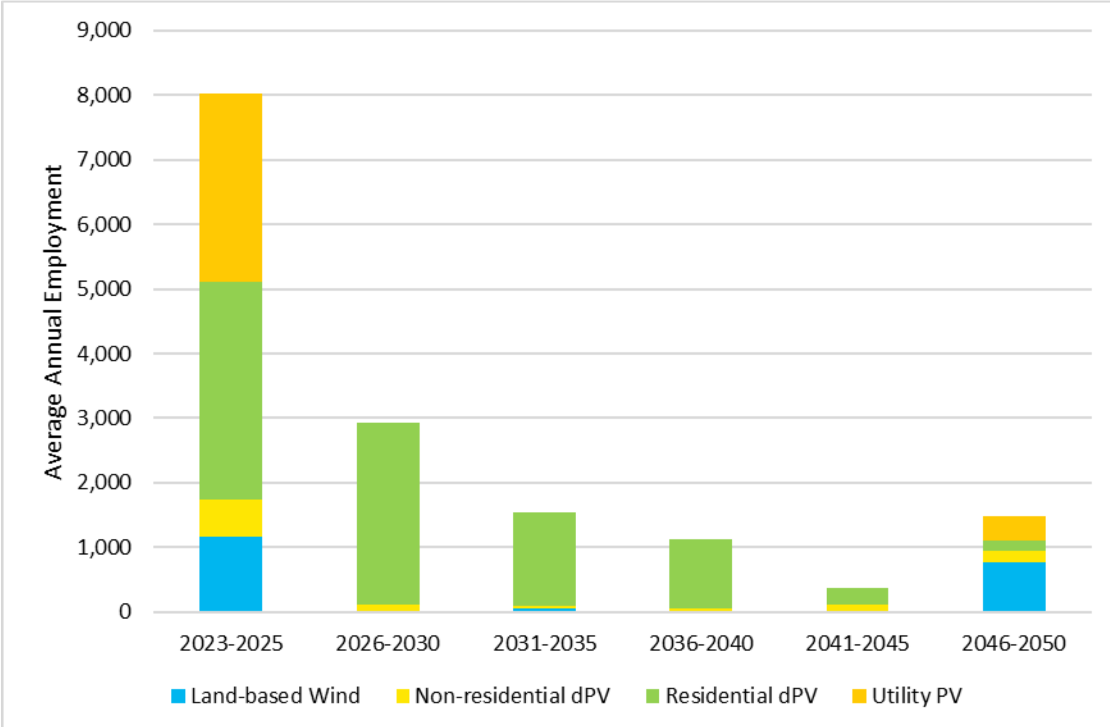


Figure 372. 3MM: Average annual employment during construction and installation by technology, 2023–2050

On average, the total number of jobs annually supported is 296 between 2023 and 2025 and increases to a total of 581 by 2050 on average, with an annual average of 403 jobs from the start to end of the analysis. The average earnings per worker are $42,017 annually across all occupations. Economic activity spurred by the O&M of these technologies supports an average of $25 million annually in value added and $36 million economic output between interindustry spending supporting the O&M of these electrical assets.

Table 58. 3MM: Average Economic Impacts During O&M, 2023–2050

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Average annually
Jobs	230	310	354	386	398	466	357
Earnings ($ million 2021)	$10	$13	$14	$16	$16	$19	$15
Earnings per worker	$43,478	$41,935	$39,548	$41,451	$40,201	$40,773	$42,017
Output ($ million 2021)	$24	$29	$31	$33	$34	$43	$32
Value added ($ million 2021)	$17	$21	$23	$24	$25	$32	$24

During 2023–2025, utility-scale PV supports the most jobs during the maintenance of the first initial operable deployment of renewable energy with 127 jobs. At the last interval (2046–2050), more capital expenditures are made and more utility-scale PV is deployed, supporting an additional 22 jobs for a total annual employment of 149 jobs on average needed to operate and maintain utility-scale solar panels. Land-based wind supports the second-greatest number of jobs initially with a total of 63 jobs during 2023–2025. In 2031–2035 when more land-based wind is deployed, two jobs were added. Lastly, in 2046–2050, the last deployment of land-based wind occurs and a total of 34 jobs were added. In sum, land-based wind has a cumulative annual 99 jobs to support the total capacity of wind energy installed. Next, residential solar supports an average of 30 jobs across the years of energy deployed. The largest addition of O&M jobs added is during 2026–2030 with a total of 75 jobs; proportionally, the second-highest amount is added in the interval later with 40 jobs added during 2031–2045. After the interval of 2036–2040 where 30 jobs are supported, the latter intervals of 2041–2050 support on average 6 jobs. Nonresidential wind energy initially supports 21 jobs during 2023–2025 and across the rest of the analysis supports on average 4 jobs from 2026 to 2050 for a cumulative total of 42 jobs.

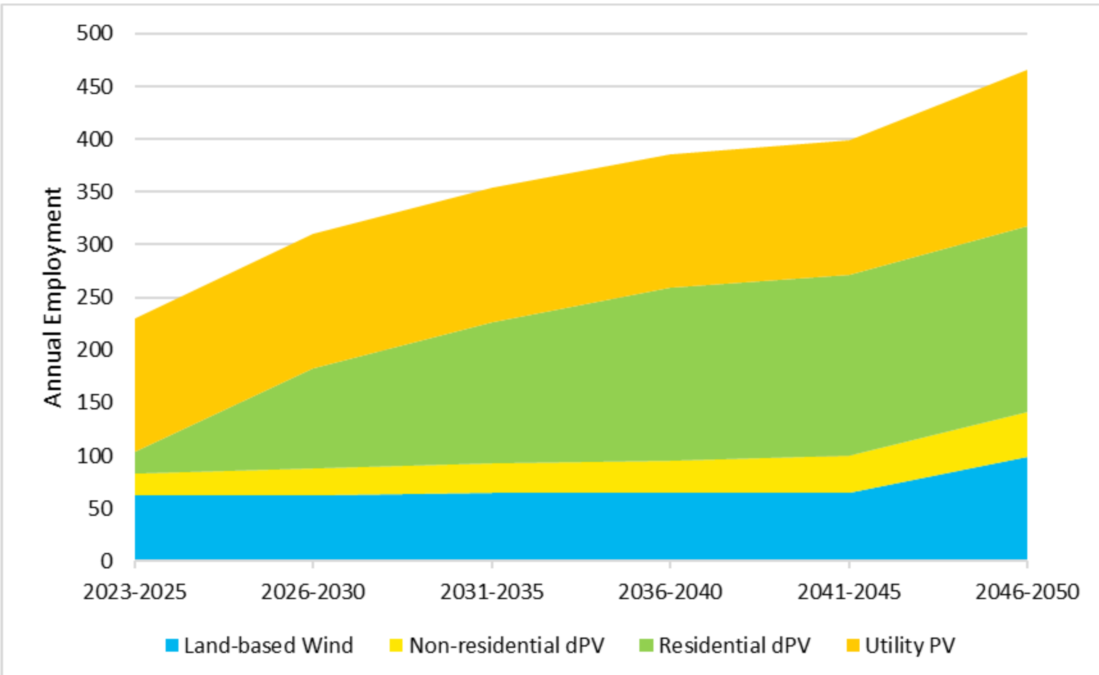


Figure 373. 3MM: Annual employment during O&M by technology, 2023–2050

12.2.4 Discussion

12.2.4.1 Overview of Economic Impacts

Transitioning Puerto Rico's electric grid to 100% renewables by 2050 supports a total of 14,892 workers across all construction efforts where the average earnings for workers supporting these projects amounts to $49,000. Residential solar construction and installation account for 48% of all jobs during construction, with utility-scale solar, land-based wind, and nonresidential accounting for 28%, 19%, and 6%, respectively.

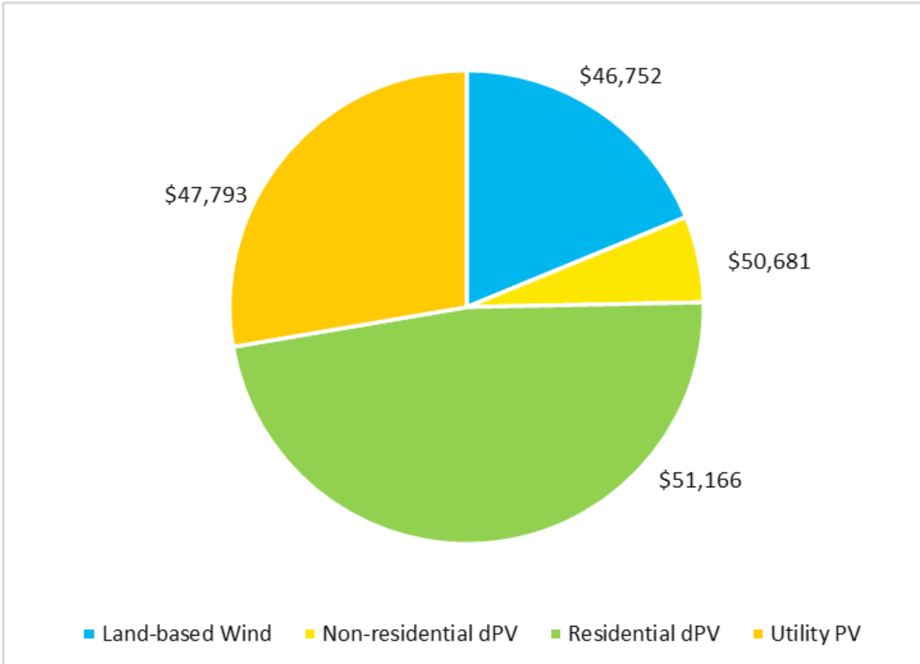


Figure 374. Proportion of jobs during O&M with corresponding earnings by technology, 2023–2050

The 3MM scenario had the highest average annual earnings for workers at $50,019 during construction and installation, and the scenario with the lowest wage is 1MS averaged at $48,450 across technologies due to capacity variation between scenarios and their respective variations. The total difference between the highest and lowest earnings across scenarios is $1,569 (Figure 376).

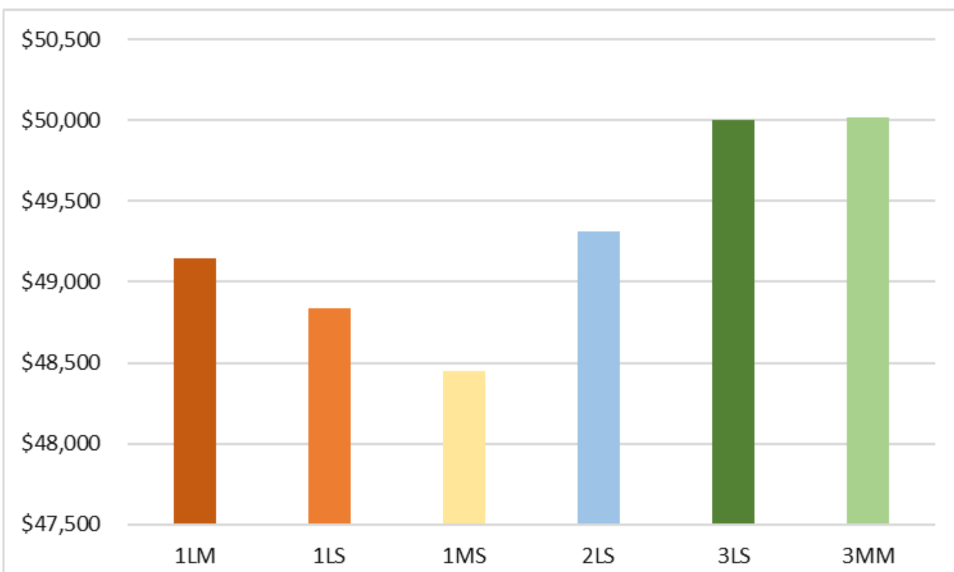


Figure 375. Average earnings during construction and installation by scenario across technologies, 2023–2050

To maintain and operate the new renewable energy assets deployed on Puerto Rico's electric grid, an annual average total across all scenarios of 2,121 lasting O&M jobs with the average earnings across all workers equaling $41,450 are required. When we examine technology, utility-scale solar energy has a proportion of 44% of these jobs, residential solar has 31% of jobs, land-based wind has 19% of jobs, and nonresidential solar has the final 7% as shown in Figure 377.

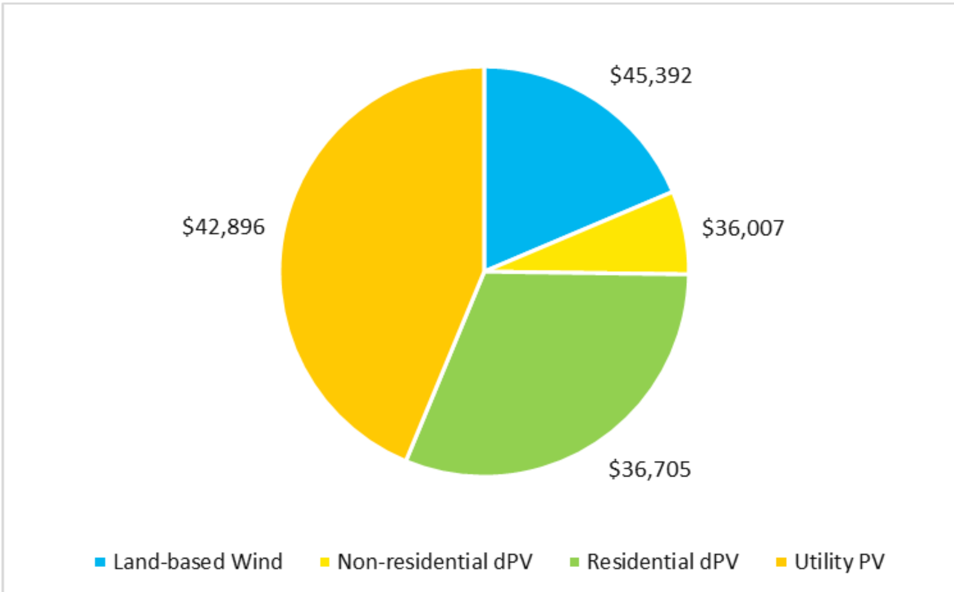


Figure 376. Proportion of jobs during O&M with corresponding earnings by technology, 2023–2050

The 3LS and 3MM scenarios have the highest average annual earnings for construction at $42,017 during construction, and the scenario with the lowest average wage is 1MS with $39,561. The total difference between the highest and lowest earnings across scenarios is $2,456 as shown in Figure 378.

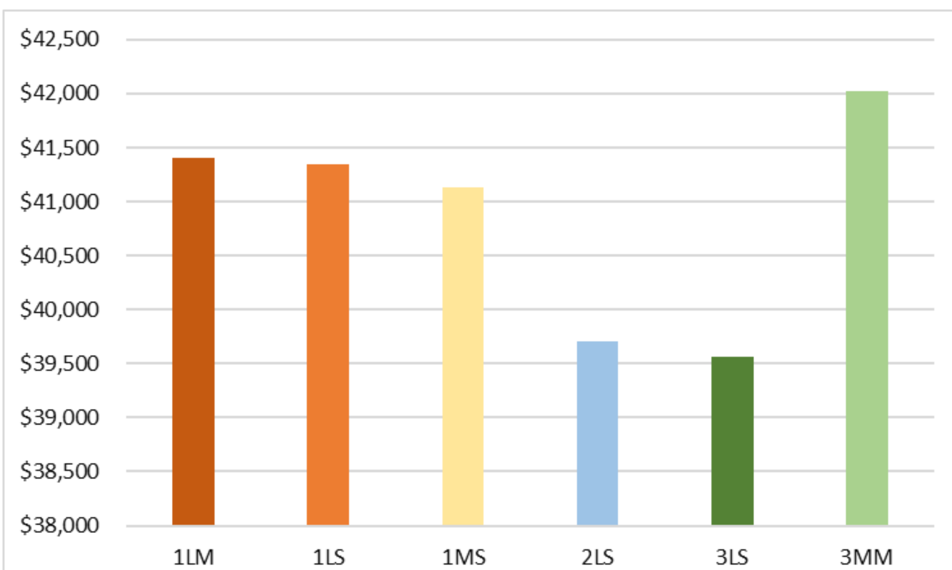


Figure 377. Average earnings during O&M by scenario across technologies, 2023–2050

12.2.4.2 Workforce Implications and Limitations of JEDI

JEDI estimates rely on accurate project information to best calibrate results for analysis. Impacts from JEDI correlate proportionally to the amount of capital investments spent for and the local content of a project. Shifts in demand over the course of the project's timeline are not factored into JEDI. This gross-level analysis contrasts itself to the portion of the macroeconomic analysis, which has levers in response to shifts in demand and factors in aspects to a project such as shifts in energy costs. As such, JEDI estimates require nuanced interpretations. JEDI assumes project details are economically feasible and no hurdles such as port accessibility for the access of imported equipment and materials or a lack of occupational skills impact the development of a given project. Lastly, JEDI does not capture positive or negative externalities such as grid reliability improvements or impacts, changes in land use, and stability of electrical rates that can occur because of the shift of an entire region's technological mix of renewable energy for the electric grid.

Holistically, there is a significant degree of demand for workers needed for both construction and O&M. For construction, the job estimates from JEDI highlight mobilizing around 5,000 construction workers in Puerto Rico by 2025 due to 40% RPS requirements. The size of the industry of construction and extraction services is approximately 33,000 (BLS 2022), suggesting the possibility of a serious effort to ensure that workforce dynamics can respond in time to construct and install these electrical assets in the short run where RPS requirements necessitate fast deployment of utility-scale solar. JEDI estimates are calibrated around the local percentage of workers available and reflect a level of local content that can take on this work and support these projects with the assumption that the projects are economically and logistically feasible. Although JEDI cannot estimate workforce implications that come from this project, serious consideration should be given to consider the right balance between job training efforts now to create a local workforce that can keep economic benefits within Puerto Rico and not be outsourced in the short run.

As opposed to construction, the incremental gains to O&M jobs over time suggest a workforce could be developed over time through effective training programs for solar and wind power technicians to create a sustainable local workforce with gainful wages that are above the average wage in Puerto Rico. Although it is also important to ensure Puerto Rico has a workforce trained to operate and maintain the deployment of energy assets under Act 17, consideration must be given to ensure aspects of geography and port access are accessible for equipment and materials needed to maintain the grid.

12.2.5 Conclusions

PR100 scenarios present a range of economic impacts across different mixes of technology and varying levels of capital and operational expenditures. Common across these scenarios, utility-scale solar has the most capacity for labor hours from jobs sourced during construction and installation while also having the highest average earnings associated during that phase. Across all energy types, all technologies have wages that are higher than median wages in Puerto Rico.

Although construction jobs yield a higher magnitude of jobs supported during construction and installation, O&M jobs are permanent because they are needed to maintain these assets as part of the electric grid in Puerto Rico. For O&M, utility-scale PV has on average 44% of jobs to other technologies across scenarios with average annual earnings of $42,896. Residential solar follows with 31% of jobs. Together with nonresidential solar, solar across technological breakdown accounts for 81% of all jobs with land-based wind having the remaining 19% of jobs supported.

Jobs supported through construction and installation efforts created more than 6× the jobs supported associated with O&M. In addition, jobs supported through construction—although lasting only the duration of the construction timeline—also had slightly higher earnings than the permanent jobs created in O&M over the lifetime of the renewable energy technologies. Both, however, have wages that are higher than the average in Puerto Rico. Although there are both more jobs supported through construction and having higher wages, the initial ramp-up in 2025 and 2050 are affected significantly by utility-scale solar. Contrasting this, O&M jobs steadily increase over time because of more deployment of renewable energy. This ramp-up carries risk dependent on the rollout of these technologies, and a mobile workforce that can capture these economic benefits is something that regulators must seriously consider.

12.3 Net Macroeconomic Impact Analysis

Key Findings

- In the initial years (2022–2025) when Puerto Rico transitioned to a more reliable and stable electric system, aggregate job and real income losses due to electricity price increases outweighed the gains caused by new investments and expenditures.
- Between 2025 and 2045 as increasingly more renewable energy resources were added to this more reliable electric system, real electricity prices stabilized and sometimes declined, resulting in generally positive, but small, economic impacts.
- Across Puerto Rico, the distribution of CapEx and O&M expenditures was relatively even across scenarios, meaning stimulative impacts did not vary substantially on a regional basis.
- Simulated economic impacts on real household income varied substantially across regions, time, and scenarios, due in part to differences in the relative sizes of the regional economies.
- Low-income households (earning $15K/year or less) were especially vulnerable to large electricity price increases, which had implications for energy justice.
- Increasing levels of distributed PV plus storage adoption were slightly more harmful to the economy relative to a higher reliance on utility-scale renewable energy resources.

12.3.1 Introduction

Puerto Rico's transition to a 100% renewable electric system will require large capital investments and associated operating and maintenance outlays for both utility-scale provision and distributed generation. This will create substantial economic benefits in the form of jobs and wages that will boost household income and create broader opportunities for increased expenditures in the Commonwealth. At the same time, financing the transition means households and businesses will confront large increases in electricity-related expenses, either through higher utility rates or expenses related to adopting and maintaining distributed PV and storage. These price increases will negatively impact the economy.

In this section, we provide estimates of the *net* economic impacts associated with the scenarios described earlier in this report. We examine these scenarios in the context of three unique time periods (i.e., epochs) where:

- Epoch 1 (2022–2025) saw considerable initial generation-related investments to achieve a more reliable electric system and concomitant electricity price increases.
- Epoch 2 (2026–2045) marked a transition to distributed PV plus storage, with smaller investment levels and relatively stable real electricity prices (i.e., inflation-adjusted).
- Epoch 3 (2046–2050) saw substantial final investments to reach 100% reliance on renewable energy.

Our analysis uses a six-region computable general equilibrium (CGE) model built specifically for Puerto Rico. The model offers a comprehensive framework to evaluate the myriad economic impacts of electric system policies. We simultaneously consider two countervailing effects for the selected scenarios.

- **Stimulative Effects:** We estimated how increases in technology-specific capital expenditures (CapEx) and operations and maintenance expenditures (O&M) related to the scenarios positively affect the Puerto Rico economy over time. The JEDI model is discussed in the prior section of this section; however, our use of the CGE model provides a wider set of economic results related to the impact on the distribution of real household income and employment impacts across a larger set of commercial sectors.
- **Contractionary Effects:** Unlike the JEDI model we also analyzed how electricity price increases affect the economy writ large as well as different economic actors. For example, commercial and industrial electricity price increases raise production costs, which can lead to lower output and employment, reduce national exports, and stoke inflation. Similarly, when households face electricity price increases, it reduces their spending power. Taken together, these effects directly lessen household well-being and indirectly affect businesses through lower customer demand for locally produced goods and services.

Although our analysis looked at the employment and income effects across the Puerto Rico economy, our work uniquely considered the impact on lower-income households who may be especially sensitive to both the positive and negative effects of the transition.

12.3.1.1 Distinct Epochs in Puerto Rico's Electric System Transition

Puerto Rico currently has a very fragile electric grid that experiences frequent outages. Increasing the reliability and resilience of the grid to meet industry standards requires significant investments. At the same time, Act 17 includes a near-term requirement (2025) for the utility to meet 40% of its retail electric sales from renewable sources of electricity generation. As a result, Epoch 1 is marked by substantial CapEx in renewable energy technologies as Puerto Rico seeks to meet reliability standards that comply with early goals of the RPS.[172] Although this led to substantial rate increases across the various scenarios, which can hurt economic activity, the Commonwealth's economy will enjoy associated job and income gains as it builds a more reliant and resilient grid. In addition, the transition from imported fossil fuels to domestic renewable

[172] As noted elsewhere the costs (and associated rate increases) of building a significantly more reliable and resilient electric system would be substantial for Puerto Rico even in the absence of adopting the specific scenarios we look at in the transition to a 100% renewable electricity system.

energy resources means that Puerto Rico can enjoy longer-term benefits including increases in energy security and jobs remaining in the Commonwealth (Carfora, Pansini, and Scandurra 2022).

By the start of Epoch 2 Puerto Rico will have largely established a reliable and resilient electric system. As such, we can look at economic changes in Epoch 2 as conditioned on a new "state of the world." Reflecting this, CapEx investments in transmission, distribution, and utility-scale renewable energy generation are much smaller than in Epoch 1, resulting in fewer new jobs and other positive economic impacts. There is, however, increased adoption of distributed PV plus storage in this time, which creates new economic activity for businesses involved in installing and maintaining these systems.

Finally, we considered the Epoch 3. Substantial new CapEx is incurred to meet the 100% RPS requirement while maintaining a reliable and resilient electric system, resulting in beneficial economic activity as well as electric rate increases.

12.3.1.2 Limitations

Our study has several limitations that should be kept in mind. First, although we quantified the impacts of both new expenditures and associated rate changes, we did not quantify the value of increased reliability and resiliency of the electric system, nor do we quantify any benefits of increased energy independence. These improvements can significantly increase both household economic well-being and business profits due to the avoidance of short and long-duration electricity outages and other disruptions. Thus, we remind readers that the electric system under any of the scenarios we discuss will be much improved over the current one.

Second, our study only considered a limited set of economic indicators. Perhaps most important, we did not consider the local and global economic benefits associated with reduced emissions from burning fossil fuels. Such benefits can be difficult to quantify but are real and substantial, and include fewer health problems (e.g., respiratory illness) and slowing the adverse impacts of climate change such as sea-level rise, more intense hurricanes, extreme heat events, etc.[173]

Third, our analysis did not examine all potential impact channels beyond the electricity sector. For example, we did not consider the impacts of the expanded adoption of EVs, which would have important impacts on the local transportation economy, including automobile dealerships and repair shops, and gasoline stations. We also did not consider the impacts of investments in energy efficiency, such as the purchase of energy-efficient appliances and the workforce needed to retrofit buildings.

Finally, our analysis only considered six potential scenarios. There are many other potential pathways to achieve the goals laid out in PR100.

[173] For examples of studies that consider such effects, see Aktar, Alam, Al-Amin (2021); Estrada, Botzen, and Tol (2017); Bielecki et al. (2020); and Barbir, Veziroğlu, and Plass Jr. (1990).

12.3.2 Economic Impact Model

To estimate the net economic impacts of the transition we used a six-region CGE model built specifically for Puerto Rico. A CGE model characterizes economic interactions among producers, households, and government. The model is founded in economic theory and is used to describe how an economic change affects the various agents. CGE models are built around a social accounting matrix, which describes commodity purchases and income payments between households, firms, and relevant government agencies. In this section, we first present the CGE model then briefly describe a social accounting matrix. We then describe the regions in the model and the data used in constructing the model.

12.3.2.1 A Six-Region CGE Model for Puerto Rico

Figure 379 (page 480) portrays the basic modeling framework in a circular flow diagram. *Households* are the primary suppliers of labor, entrepreneurship, and capital to the economy. In exchange, they receive wages, profits, and other returns on investments. Households use this income to purchase goods and services (including electricity), save for the future, and pay taxes. When prices of goods and services change, households are affected through changes in real household income (i.e., income adjusted for price changes, or purchasing power). When a price increases, households respond by purchasing less of the good. However, higher prices of an essential good like electricity—which has very inelastic demand—means households typically spend more on the good, leaving them with less money to spend on other goods and services.

Our model considered six household income groups[174] for each region which allowed us to examine the impact on low-income groups. Specifically, previous research shows that lower-income households are more vulnerable to electricity rate increases, as they tend to allocate a larger share of their disposable incomes to utilities than do more affluent households (Baxter 1998).

Firms—which comprise of industrial and commercial entities—are the primary users of labor and capital (e.g., buildings, machines, and equipment). Firms use these inputs—along with other intermediate inputs (e.g., materials and electricity) to produce goods and services, which they sell to both households and other firms. Higher electricity rates affect the costs of production for firms and can impact final output prices.

Governments collect taxes from both households and firms, using this revenue to provide a variety of goods and services, such as education, healthcare, and infrastructure. The CGE model also accounts for trade both between regions in Puerto Rico and between Puerto Rico and other places (i.e., "*Rest of the World*"). When domestic prices increase relative to the rest of the world, export sectors become less competitive.

A CGE model is flexible enough to examine both demand- and supply-side changes. Demand-side changes are caused by factors such as changes in household and government spending, business investment, and exports. Supply-side changes are caused by factors such as changes in technology, input prices, wages, and taxes.

[174] Incomes groups were as follows: Less than \$10,000; \$10,000-\$15,000; \$15,000-\$25,000; \$25,000-\$35,000; \$35,000-\$75,000; and Greater than \$75,000.

A social accounting matrix rests at the core of a CGE model and reflects the data the describes the interactions between households, firms, government, and the rest of the world. The social accounting matrix provides an integrated system of accounts that consistently relate production, consumption, investment, and the public sector from both microeconomic and macroeconomic perspectives.[175]

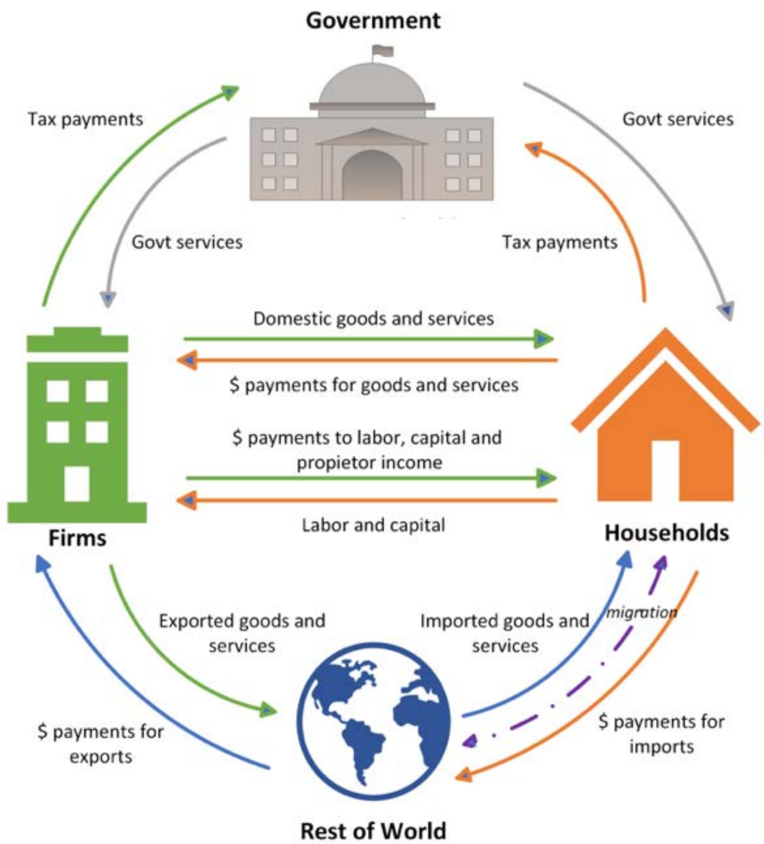


Figure 378. CGE model structure

Source: Amini et al. (2023)

12.3.2.2 Social Accounting Matrix

From the microeconomic perspective, each household's flow of income and expenditures must satisfy its budget constraint. This means that a household's total income must equal its total expenditures, which include consumption, taxes, and savings. When real household income falls due to job losses and/or higher prices, an economy will contract.

From the macroeconomic perspective, transactions between sectors and agents must satisfy the standard aggregate accounting identities. For example, the income identity requires that Puerto Rico's GDP equal the sum of consumption, investment, government spending, and net exports (exports minus imports).

[175] For a complete description of the SAM approach underlying the CGE model see Schwarm and Cutler (2003).

12.3.2.3 Defining Regions, Model Data, and the Social Accounting Matrix

To understand regional differences in economic impacts of the transition we demarcated Puerto Rico into six regions (Figure 380).[176] The regions were developed in consult with various local officials and others with a good working knowledge of Puerto Rico's economy. In our work, our top-line results are presented for both Puerto Rico as a whole and each region. We do this because new investments are spatially anchored, meaning each region will be impacted differently by the transition. In regions with substantial new investments per household, the positive impacts will be greater than those with little new spending. These differences arise largely from the location of new wind and solar generation facilities and regional differences in the adoption of distributed PV plus storage. Similarly, regions with a higher share of lower-income households will be more adversely affected by electricity price increases than regions with a larger share of high-income households.

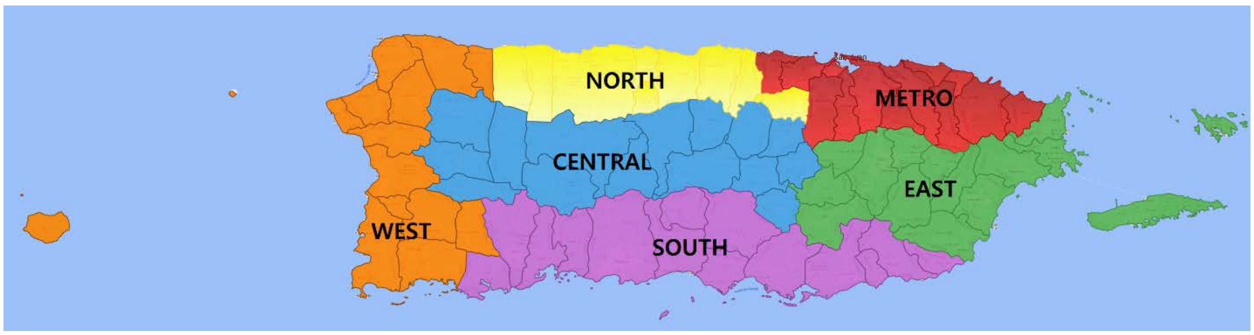


Figure 379. Modeling regions

The social accounting matrix numerically captures the resource flows described in Figure 379, drawing on several data sources. For household data, we used the U.S. Census Bureau's American Community Survey Public Use Microdata Sample (PUMS), which provides sample data for Puerto Rico depicting the total number of households, the number of workers in each household, and total household income (including labor income earned by workers across different sectors, for example manufacturing and retail). PUMS data are reported at the geographic level of the Public Use Microdata Area (PUMA).[177] We matched these PUMAs to the regions described in Figure 380.

Production sectors (i.e., firms) were organized using the North American Industry Classification System (NAICS). Key variables include total industry output, employment, and wages. For employment, we used U.S. Bureau of Labor Statistics (BLS) and PUMS data to summarize the level and distribution of employment across six different wage groups over many NAICS sectors that we subsequently aggregated into two-digit NAICS groups. We further refined the distribution of workers employed in different regions across Puerto Rico using the Puerto Rico Community Survey Data (SDC-PR n.d.).

Capital (e.g., buildings, factories, and computers) and its demand are other important model aspects. Our capital stock estimates were informed by property tax collections from The

[176] Each region is comprised of multiple municipalities. The municipalities in each region are shown in Table J-1 in Appendix J.
[177] PUMAs are nonoverlapping areas that partition Puerto Rico into contiguous geographic units. PUMAs contain roughly 100,000 people each (U.S. Census Bureau 2023b).

Financial Oversight and Management Board for Puerto Rico (FOMB), which reports real property counts and values by municipality. We made some modifications based on information in Cornia and Walters (2019) and data from the U.S. Bureau of Economic Analysis (Cornia and Walters 2019). For intermediate input demand (interindustry transactions), we used IMPLAN (Impact Analysis for PLANning) data[178] for Puerto Rico to obtain input-output coefficients between the two-digit NAICS firms.

Household consumption is an important part of our analysis, especially related to electricity. We started with IMPLAN household consumption values across all goods and services, and slightly modified them using the BLS Consumer Expenditure Survey. To better model household electricity consumption in Puerto Rico, we used EIA data (n.d.-c) and Cordero-Guzman (2019). For total industry expenditures, we used IMPLAN data, which provides each industry's annual total spending on various inputs, including electricity.

On the electricity sector's supply-side we categorized existing production across a variety of sources: fossil fuels, solar, wind, hydropower, and biofuels. These sectors were modeled using a combination of IMPLAN data and guidance from EIA.

Overall, changes related to the transition can have differential impacts on economic sectors and households. These differences may be related to the specific location and type of related investments, the location of workers, or the region's general economic makeup.

12.3.2.4 A Brief Description of Puerto Rico's Economy

BLS data show Puerto Rico's economy experienced net job losses over the past 18 years, falling from 1.05 million jobs in mid-2004 to 956,000 in September 2023 (Figure 381). However, job totals were up over pre-pandemic levels; on the eve of the Covid-19 recession the Commonwealth was home to about 884,000 jobs. Between September 2021 and September 2023 Puerto Rico added more than 55,000 jobs, or about 27,500 (3%) per year. This was a remarkable reversal of fortunes in an economy that lost an average of about 8,500 jobs per year from 2003 to 2019.

[178] IMPLAN, https://implan.com/.

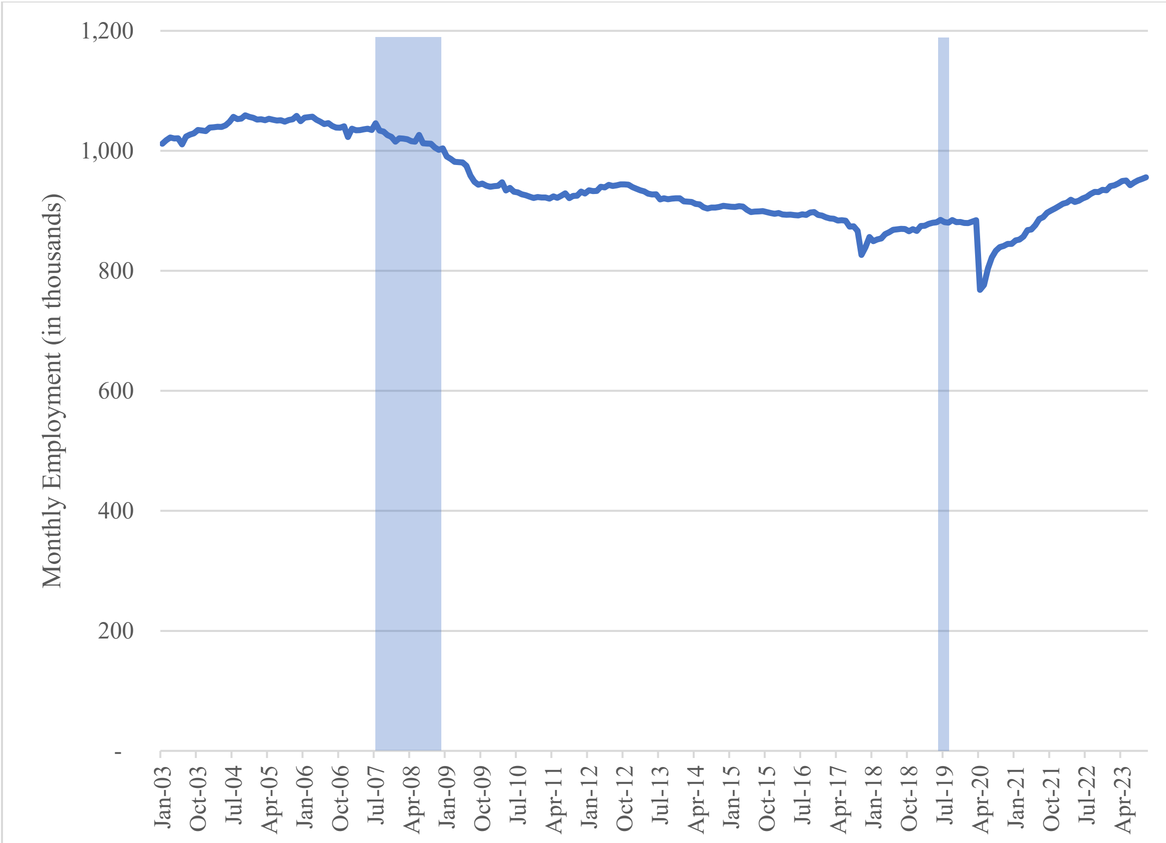


Figure 380. Puerto Rico monthly nonfarm employment totals, January 2003–September 2023, seasonally adjusted

Source: U.S. Bureau of Labor Statistics
Shaded areas indicate U.S. recessions.

Puerto Rico's economy varies across the Commonwealth. Economic activity—especially higher-level services (e.g., finance, legal, and medical) —is largely concentrated in coastal cities and towns. The interior is more rural, and agriculture is an important industry. Related, household incomes also vary across Puerto Rico, with higher-income households typically living in coastal regions.

In Table 59, we show the sectoral employment across the six regions for most two-digit NAICS codes for 2019. The Metro area employed the largest number of workers while the Central region employs the fewest. A key aspect of our CGE model is that it allows us to examine changes in the level and distribution of employment across the six regions during the transition to 100% reliance on renewable energy.

Table 59. Estimated Sectoral Employment by Region in Puerto Rico, 2019

Sector	Metro	East	West	North	South	Central
Agriculture, mining	1,550	846	1,487	1,660	3,720	2,409
Water, sewage, and other systems	363	201	102	232	275	112
Natural gas distribution	1,088	603	305	700	824	337
Electric power transmission and distribution	2,176	1,207	609	1,395	1,646	674
Construction	14,839	9,992	4,894	7,185	6,827	5,224
Manufacturing	18,058	24,864	15,399	12,214	17,929	11,115
Wholesale trade	29,297	7,459	6,386	5,845	4,235	5,338
Retail trade	54,263	25,581	16,485	17,922	15,925	11,390
Service	103,780	30,721	18,031	20,313	19,088	11,107
Educational services	36,196	18,102	15,221	10,602	15,295	10,467
Health care and social assistance	43,672	22,613	14,824	20,401	16,078	11,971
Arts and accommodation	42,309	19,587	11,741	10,536	12,574	8,785
Total	347,591	161,776	105,484	109,005	114,416	78,929

Source: PUMS, U.S. Census Bureau

In Table 60, we show select regional population and income differences for 2019. San Juan is the heart of the Metro area, and the region is home to 37.1% of households in Puerto Rico. All other regions are less than half its size, with the Central region having the smallest number of total households. The Metro area earns almost half of the total household income earned in the Commonwealth and has the highest average income per household ($39,412). The Central region has the lowest average income per household ($24,749).

Table 60. Key Household Indicators, by region, 2019

Region	Number of households	Percentage of Households	Total income (in millions $)	Income per household
Metro	434,575	37.1%	$17,127	$39,412
East	175,170	15.0%	$6,442	$36,774
West	155,469	13.3%	$3,951	$25,413
North	135,551	11.6%	$4,131	$30,474
South	159,519	13.6%	$4,162	$26,094
Central	110,699	9.5%	$2,740	$24,749
Total	1,170,983	100%	$38,553	$32,924

Source: PUMS, U.S. Census Bureau

Because low-income households spend a relatively large share of their income on electricity it is important to understand the effects of the transition on these households. In Table 61, we report baseline household distribution across the six regions for six household income groups. More than half of all households in Puerto Rico earn less than $25,000/year. The Metro area has a higher share of higher-income households compared to all other regions, with 13.2% of all households having more than $75,000 in annual income. Our CGE analysis identifies how the transition to 100% reliance on renewable energy affects household income distribution across the six regions.

Table 61. Distribution of Households by Income, 2019

HH Type	Metro Households	Percent of Region	East Households	Percent of Region	West Households	Percent of Region
HH1 < $10k	101,685	23.4%	43,037	24.6%	53,389	34.3%
$10k < HH2 <$15k	41,352	9.5%	21,226	12.1%	19,877	12.8%
$15k < HH3 <$25k	74,319	17.1%	31,960	18.2%	30,492	19.6%
$25k < HH4 <$35k	52,601	12.1%	24,694	14.1%	18,949	12.2%
$35k < HH5 <$75k	107,366	24.7%	37,153	21.2%	23,901	15.4%
$75k > HH6	57,252	13.2%	17,100	9.8%	8,861	5.7%
Total	434,575	100.0%	175,170	100.0%	155,469	100.0%
HH Type	**North Households**	**Percent of Region**	**South Households**	**Percent of Region**	**Central Households**	**Percent of Region**
HH1 < $10k	33,130	24.4%	48,874	30.6%	33,688	30.4%
$10k < HH2 <$15k	17,997	13.3%	23,765	14.9%	15,117	13.7%
$15k < HH3 <$25k	27,214	20.1%	29,795	18.7%	23,759	21.5%
$25k < HH4 <$35k	17,496	12.9%	18,419	11.5%	13,101	11.8%
$35k < HH5 <$75k	29,964	22.1%	30,112	18.9%	19,788	17.9%
$75k > HH6	9,750	7.2%	8,554	5.4%	5,246	4.7%
Total	135,551	100.0%	159,519	100.0%	110,699	100.0%

Source: PUMS, U.S. Census Bureau

In Table 62, we show the estimated average monthly and annual household electricity expenditures for each household income group.[179] In tandem with the previous table, we see a lower-income households spend a relatively larger portion of their income on electricity. For example, if a household has $10,000 in income (the top of HH1) and spends $808/year on electricity, then a little more than 8% of their income is allocated to electricity. By comparison, a household that earns $75,000 (the bottom of HH6) and spends $1,571/year for electricity, then about 2.1% of their total income is allocated to electricity purchases.

[179] These expenditures may not line up precisely with other measures of household energy burden reported elsewhere in this study due to differences in data sources and requirements of our modeling approach.

Table 62. Estimated Electricity Expenditures by Household Income Group in Puerto Rico 2019

Household Income Group	Number of Households	Annual Electricity Spending per Household	Monthly Electricity Spending per Household	Annual Total Expenditures
HH1 < $10k	313,803	$808	$67	$253,766,210
$10k < HH2 <$15k	139,334	$970	$80	$135,215,287
$15k < HH3 <$25k	217,539	$1,081	$90	$235,359,795
$25k < HH4 <$35k	145,260	$1,251	$104	$181,720,260
$35k < HH5 <$75k	248,284	$1,433	$119	$355,920,080
$75k > HH6	106,763	$1,571	$130	$167,741,755
Total	1,170,983			$1,329,723,387

Source: Authors' calculations based on data from EIA and Cordero-Guzman (2019)

Overall, firms spend $2.2 billion total and households spend a total of $1.3 billion on electricity in our reference data. Firm and household electricity payments as a share of total expenditures average 5.3% and 3.5%, respectively. This is the basis for the electricity price changes we model later.

12.3.3 Economic Impact Channels and Energy Justice

We estimated the net economic impacts of a transition to 100% renewable energy by looking at several "impact channels." The first channel is the positive effects associated with increases in local expenditures related to the transition, considering both one-time CapEx investments and ongoing O&M expenditures. These impacts were related to both utility-scale generation, storage, transmission, and distribution, and the increased adoption of distributed PV plus storage.

While the new expenditures related to the transition generate positive economic impacts, there were also associated negative impacts. In particular, the transition will be expensive, meaning both businesses and households will pay more for electricity, whether through higher utility rates or through the substantial costs associated with adopting distributed PV plus storage.

In the second impact channel we estimated two primary negative economic effects of electricity price increases. First, higher prices mean total electricity expenditures increase as a share of an agent's budget, reducing the consumption of other goods and services, thus reducing economic activity. Second, when businesses face higher production costs—due to higher electricity prices—they typically increase the price of their products. This leads to both lower levels of production and employment (which reduces household labor income) and higher prices (i.e., inflation). Both effects reduce real household income.

The net economic impact analysis incorporated both the positive effects of increased investment and the adverse impacts of increased in average electricity prices, relative to the baseline. The CGE model simultaneously solved for the impacts of these various mechanisms and simulated the ultimate impact on economic activity through the interaction of all directly and indirectly affected sectors.

12.3.3.1 Impact Channel 1: Changes in Investment and O&M Expenditures

As Puerto Rico increases the reliability and resiliency of its electric system and transitions to 100% renewable electricity there will be significant expenditures related to installing, operating, and maintaining the various systems. These expenditures have a positive economic impact, stimulating local output, employment, and household income. Impacts can be either short-lived, related to the initial capital expenditures (i.e., CapEx) or ongoing, related to the expenses associated with operating and maintaining the system (O&M). CapEx and O&M expenditure estimates by generation technology type for each scenario are provided from other sections.

For utility-scale expenditure impacts (primarily utility-scale onshore wind, solar, batteries, and B100) our work relied on the CapEx and O&M estimates based on the Engage model, which helps determine the lowest-cost deployment mix when transitioning to renewables over the 25-yr planning horizon. For CapEx and O&M expenses related to the adoption of distributed generation and storage, our work is informed by the Distributed Generation Market Demand Model (dGen). This model analyzes factors that affect the demand for DERs such as commercial and residential rooftop solar and storage.

Estimates of detailed spending patterns within each of these categories are informed by the National Renewable Energy Laboratory's (NREL's) JEDI and the IMPLAN models. Our estimates consider only those expenses accrued by economic activity taking place specifically in Puerto Rico. Therefore, we excluded expenditures on imported goods related to the projects. Here, we assumed most major system components (e.g., turbines and blades, solar panels, batteries) are imported, reflecting the current lack of capacity to produce such components locally. Should some or all these components be produced locally, then the positive economic impacts would increase relative to what we report here.

12.3.3.2 Impact Channel 2: Changes in Electricity Prices

Increased CapEx and O&M expenditures will spur new economic activity in Puerto Rico. *However, these gains may be partially or fully offset by increases in electricity prices.* In this section we describe how we estimated the economic impacts of the transition attributable to electricity price increases—relative to a baseline projection—under each of the scenarios.

In general, our model has two types of agents. The first type relies on the utility and faces higher *rates*, which increase their annual expenditure on electricity. The second type adopts distributed PV plus storage. While an adopter's payments *to the utility* may fall as their total power purchases fall, they still incur *costs* related to paying for the new distributed system…. there is no free lunch. Overall, our analysis suggests real electricity *prices* will increase over time for both utility customers and distributed PV adopters, relative to 2022 utility rates.[180]

Due to data limitations, we combined these two types of agents into a "representative customer" for each of four customer types: (1) commercial, (2) industrial, (3) moderate-to-high-income residential, and (4) low-income residential. As such, we were not able to differentiate between adopters and nonadopters. Notably, price increases for business customers would impact the

[180] By prices, we refer to a weighted combination of (1) rate changes that affect utility customers and (2) cost changes that affect adopters. Essentially, this captures changes in the price per kilowatt hour an average user faces, regardless of the source of electricity.

economy differently than would price increases for residential customers. We now discuss the unique mechanisms for each group.

12.3.3.2.1 Impact Channel 2.1: Electricity Price Increases and Commercial and Industrial Users

Because electricity is an important production factor (i.e., intermediate input), changes in its price can significantly impact Puerto Rico's commercial and industrial enterprises. In the CGE model, we assumed perfectly competitive markets, with profit-maximizing firms using a constant-returns-to-scale, constant elasticity of substitution (CES) production technology[181] that relies on labor, capital, and intermediate inputs. Total production, relative input prices, and their productivity affect input demand. In cases where electricity prices increase, production costs also increase. In the CGE model, this shifts the firm's (industry's) supply curve to the left, reducing output and increasing the market price of the final good or service.

Overall, there are two important macroeconomic effects. First, declining output reduces labor demand, which leads to falling employment and wage income losses. This means some households will have less income. Second, higher prices lead to an increase in the economy's price level (*CPI*), reducing real household income for all households (i.e., lower purchasing power).

In the CGE model, sector-level effects on intermediate input demand (V_i) are captured in equation (1),

$$V_I = V_{0I}\Pi_J(P_J TT_J\ (1 + \Sigma_{GS}TAUC_{GS,J})/(P_{0J}(1 + \Sigma_{GS}TAUQ_{GS,J})^{DELTA_{J,I}} \qquad (1)$$

where V_{0I} is the base level of intermediate inputs used across sectors (*J* is the transpose of *I*). P_I is the price of final demand of goods or services indexed by *I*, and $P0_I$ is the base level price vector (any variable specified with a zero is a base level value). *DELTA* represents own- and cross-price elasticities, and Π_J is the product (multiplication) operator. The parameters $TAUC_{GS,J}$ and $TAUQ_{GS,J}$ are sales and property and use tax rates, which are unchanged in our analysis. The parameter TT_I facilitates modeling electricity price changes, which can vary across industry types (e.g., commercial, industrial).[182]

The overall impact of changing electricity prices on commercial and industrial enterprises varies by both the magnitude of the price change and the sector. For example, businesses that are more electricity-intensive will be more affected than those that are less so. Additionally, the impact will depend on the flexibility of firms to adjust their input mix. Firms that can substitute other inputs for electricity will be less affected than those that cannot.

[181] The CES production function assumes the production process being modeled has a constant percentage change in labor or capital proportions due to a percentage change in the marginal rate of technical substitution.

[182] We created TT_I as vector of ones that is multiplied by P_I wherever economic decisions are made that are influenced by prices. The advantage of this specification is that we can control the increase in electricity rates exactly. As an example, if electricity rates increase by 10%, then we set TT_{ELEC} to equal 1.1.

12.3.3.2.2 Impact Channel 2.2: Electricity Price Increases and Households

There are two main channels through which changing residential electricity prices can impact the Puerto Rico economy:

1. **Changes in Real Household Income:** Changes in electricity rates impact household purchasing power. When prices increase, for example, consumers have less money to spend on other goods and services. This decline in real income leads to a decline in demand for goods and services, which reduces economic activity.
2. **Relative Price Changes:** When electricity rates increase it becomes more expensive relative to other goods and services. This can result in households changing the mix of goods and services they consume. For example, a price increase may lead to households purchasing less electricity and more other goods and services.

Importantly, the impact of electricity price changes for Puerto Rican households depends on several factors, including the magnitude of the price change, and general household responsiveness to price changes. In our model, the effects are reflected in the following two equations:

$$CPI_H = \Sigma_I P_I\, TT_I(1 + \Sigma_{GS} TAUC_{GS,I})CH_{I,H} / \Sigma_I(P0_I(1 + \Sigma_{GS} TAUQ_{GS,I}))CH_{I,H} \qquad (2)$$

$$CH_{I,H} = CH0_{I,H}((YD_H/YD0_H)/(CPI_H/CPI0_H))^{BETA_{I,H}}\, \Pi_J(P_J TT_J(1 + \Sigma_{GS} TAUC_{GS,J}))/(P0_J(1 + \Sigma_{GS} TAUQ_{GS,J}))^{LAMBDA_{J,I}} \qquad (3)$$

In equation (2), overall consumer prices are reflected in CPI_H, the consumer price index faced by each household group (*H*), distinguished by annual household income. $CH_{I,H}$ is real household consumption of various goods and services. Once again, electricity rate changes were introduced through the parameter TT_I. Note that increases in TT_{ELEC} cause the CPI_H to rise, depending on the relative proportions of electricity demanded by each household group. Any variable with a 0 at the end represents base data.

Equation (3) details real household consumption ($CH_{I,H}$) of a variety of goods and services, including distributed generation technologies such as PV and storage. The first term represents real household income, while relative price changes are reflected in the second term. The variable YD_H is nominal disposable income across households, and when divided by the CPI_H is converted to real values. Reductions in real income force households to reduce purchases of goods and services and may also adversely impact savings.

$Beta_{I,H}$ is a set of income elasticities, describing how consumption of various goods and services changes as real income changes. *Lambda* is a square matrix of own- and cross-price elasticities.[183] Once again, we use TT_J (J is the transpose of I) to introduce changes in electricity rates, with the specification flexible enough to allow different household income groups to pay different electricity rates. The model's output demand equations, not shown here, reflect the fact that demand for locally produced goods and services is affected by changes in real household consumption, an important aspect of the circular flow diagram. For example, if households

[183] We assume an own-price elasticity of -0.16 (highly inelastic) for households and an own-price elasticity of -0.22 for firms; these elasticity values are consistent with the empirical literature on this topic.

allocate more (less) of their income to electricity, they have less (more) to spend on other goods and services.

Equation (4) describes nominal disposable household income. It consists of wage and capital income (Y_H), returns to entrepreneurship (i.e., profit) and transfer payments (PRIVRET and TP), less tax payments (TAUH). Total wage income is tied to labor demand; when labor demand falls, so, too, do wages. Thus, we can see two related mechanisms by which reduced economic activity lowers nominal household income: fewer workers and lower wages.

$$YD_H = Y_H + PRIVRET_H\ HH_H + \Sigma_G TP_{H,G}\ HH_H - \Sigma_{GI} PIT0_{GI,H}\ Y_H - \Sigma_G TAUH_{G,H}\ HH_H \qquad (4)$$

12.3.3.3 Energy Justice Considerations

One of our primary interests is examining how building a more resilient and reliable electric system while meeting the goals of Act 17 will affect households across Puerto Rico. As noted, both impact channels can affect real household income, either through price changes or changes in job-related income. As shown above, lower-income households may be particularly vulnerable to sharp increases in electricity prices.

In considering the energy justice implications of any transition, analysts often look at "energy burden," which is measured as how much of a household's budget is spent on purchasing energy, including electricity. However, our model does not readily supply this metric, due, in part, to the difficulty in untangling changing electricity prices over time for distributed PV adopters versus those that remain primarily reliant on the utility. Instead, we focused on real household income, looking at its dynamics for each household income group. While this metric is not prevalent in the energy justice literature, it can be a preferred measure because it considers not only the effects of changing household electricity expenditures, but also accounts for how changes in production costs (due to changing electricity prices) change the prices of other goods and services a household may purchase.

12.3.4 Inputs and Assumptions

Transitioning to meet PR100 goals requires a new generation portfolio, improvements in the transmission and distribution infrastructure, and widespread adoption of distributed generation and storage. To pay for this transition, customers will likely pay higher prices for electricity, either through higher rates or through the costs associated with adopting distributed PV plus storage systems. This section describes how we estimated annual CapEx and O&M costs, as well as the associated changes in electricity prices and distributed PV adoption costs. This information was entered into the CGE model for each scenario with subsequent results compared to the 2022 Puerto Rico economy.

12.3.4.1 Estimating Changes in CapEx and O&M Expenditures

Like the JEDI analysis in Section 14.2, we estimate the transition's positive economic impacts using CapEx and O&M expenditure estimates from other project tasks.[184] Relevant expenditure outputs from the dGen model (Section 7.4, page 199) and Engage model (Section 8.4, page 224)

[184] Our model's estimated impacts of these effects are highly consistent with JEDI results, but not identical, due to slight differences in modeling methods and our inclusion of general equilibrium impacts that are not considered in JEDI.

were derived from NREL's bottom-up cost estimates. These models considered not only current costs associated with installing and maintaining various technologies, but also projected future changes in key cost drivers due to technological change and increased efficiency.[185] For distributed PV plus storage, the results discussed in Section 7.4 (page 199) were used as inputs for annual, inflation-adjusted CapEx and related O&M expenditure estimates for commercial, industrial, and residential PV and storage for each municipality, which we aggregate to the regional level. The results discussed in Section 8.4 (page 224) were used as inputs for utility-scale expenditures, which include onshore wind, PV, batteries, and B100.

12.3.4.2 Estimating Changes in Electricity Prices

There are two general agents in our analysis, utility customers and distributed PV adopters. These agents can be residential, commercial, or industrial entities. Utility-reliant agents purchase their electricity from the utility, and we considered the per kwh rate as its price. We calculated real rate changes for various utility customer classes by adjusting the nominal rate trajectories described in Section 14.1. In an economy that changes over time, equation (3) shows that "fair comparisons" to an earlier baseline need account for changes in both overall prices (i.e., $CPI_H/CPI0_H$) and household income (i.e., $YD_H/YD0_H$). FOMB's projections of future inflation and per capita GDP were the basis for such adjustments.

Establishing the effective price of electricity for distributed PV adopters, the second type of agent, was less straightforward. Unlike utility customers who "pay-as-they use" for each kwh (i.e., variable costs), much of the electricity costs distributed PV adopting agents incur happen up front. Over time, these large, fixed costs are recouped through savings accrued by avoiding payments to the utility for electricity as it is used.

For our analysis, we converted the distributed PV adopter's long-term expenditure dynamic into a price-series that is conceptually comparable to the price a utility customer would pay. In doing so we considered (1) any payments distributed PV adopters make related to installing and maintaining their own generation and storage systems, (2) any costs associated with remaining connected to the utility (for back-up power),[186] and (3) any costs related to electricity purchases in instances where they were unable to meet their electricity needs solely through their own distributed PV plus storage system. As a general formulation:

Monthly electricity costs = monthly cost of system + monthly O&M costs + monthly connection costs + monthly purchased electricity (5)

Regarding the first two terms of equation (5), we assume that distributed PV adopters were subject to both up-front, one-time expenditures (i.e., CapEx) and ongoing O&M expenses.

We assumed residential customers lease their systems and modeled effective electricity prices through an estimated lease payment. This lease payment varied by the system's size: we assumed higher-income households adopted larger PV and storage systems than did lower-income

[185] An example of NRELs "bottoms up" cost modeling procedures can be found at "Solar Technology Cost Analysis , NREL, https://www.nrel.gov/solar/market-research-analysis/solar-cost-analysis.html. More information on the evolution of these costs over time is available through NREL's Annual Technology Baseline (https://atb.nrel.gov/).
[186] In our analysis, we assume nearly all distributed PV adopters remain connected to the utility (i.e., no defection), even if they can meet most of their electricity consumption needs through behind the meter technologies.

households. In practice, commercial and industrial users may pay for their distributed PV systems up front. For these customer classes we amortized the up-front costs over time, allowing us to represent such expenditures through a series of smaller monthly payments.[187]

Recognizing that technological change and other efficiency improvements will reduce system costs over time, projected payments (adjusted for inflation) for new adopters decline over time in accordance with NREL's Annual Technology Baseline (ATB) for relevant system components and O&M. However, once an agent adopts distributed PV, we assumed their nominal monthly lease payment remains fixed.

Through 2034, we assumed new adopters receive the investment tax credit, set at the rate applicable to that year; no other potential incentives that reduce the costs of adoption (e.g., grants for low-income households) were considered. To establish a distributed PV price-series that is conceptually consistent with utility rates, electricity costs were converted to a weighted per kwh basis, based on total projected usage.

In our analysis, agents that adopt distributed PV plus storage sometimes pay higher electricity prices than they would have had they remained reliant on the utility, especially in the early years. Over time, reductions in distributed PV and storage costs, combined with increases in utility rates, eliminate all or much of these differences. However, even if distributed PV plus storage prices are relatively higher, it may be economically rational to adopt, for two reasons. First, some adopters may see resiliency and reliability benefits, as power surges or prolonged power losses can be costly. Effectively, distributed PV and storage can be seen as insurance against these downside risks. Second, because our analysis ends in 2050, it does not capture longer-term relative price declines under distributed PV once the system is considered paid-off.

12.3.5 Analysis and Results

In this section we present the projected net economic impacts across the six scenarios. In addition to providing overall impact estimates, we disaggregate our findings to compare the positive impacts of additional CapEx and O&M expenditures for both utility-scale and distributed PV plus storage with the negative impacts of higher electricity prices. Looking across the scenarios over the study time frame, we have several critical findings:

- Increased investment and O&M associated with utility-scale and distributed-scale renewable energy resources lead to job growth.
- Higher electricity prices adversely affected both businesses and households.
    - In Epoch 1 the negative economic impacts of price increases overshadow the stimulative expenditure effects.
    - In Epoch 2, relatively flat real electricity prices meant net economic impacts tend to be positive but relatively small.

[187] The analysis discussed in Section 7.4 (page 197) provides details about the costs associated with commercial, industrial and residential distributed PV plus storage adoption, including both installation and O&M costs.

- Lower-income households were more adversely impacted by price increases than higher-income households.
- Under higher levels of distributed PV adoption, economic impacts were slightly negative in Epoch 2, though small.

We begin this section by sharing the specific model inputs, looking at CapEx and O&M expenditures as well as concomitant changes in electricity prices. We then show results from simulations that simultaneously consider the additional expenditures and related electricity price increases.

12.3.5.1 Model Inputs: CapEx and O&M Expenditures

As described above, the Engage and dGen models generated inflation-adjusted CapEx and O&M expenditure profiles for each technology under each scenario for various time periods. The Engage model provided utility-scale results and the dGen model provided distributed PV plus storage results. Figure 382 shows the aggregation of these profiles, net of imported goods and services, for select years. The largest expenditures are in 2025 and 2050, primarily reflecting substantial new utility-scale capital investments in those years. Based on technology-specific spending patterns, we allocated these expenditures to appropriate sectors within the Puerto Rico economy. To initiate our simulations, we simply shocked aggregate demand by the relevant amount in each of these sectors.

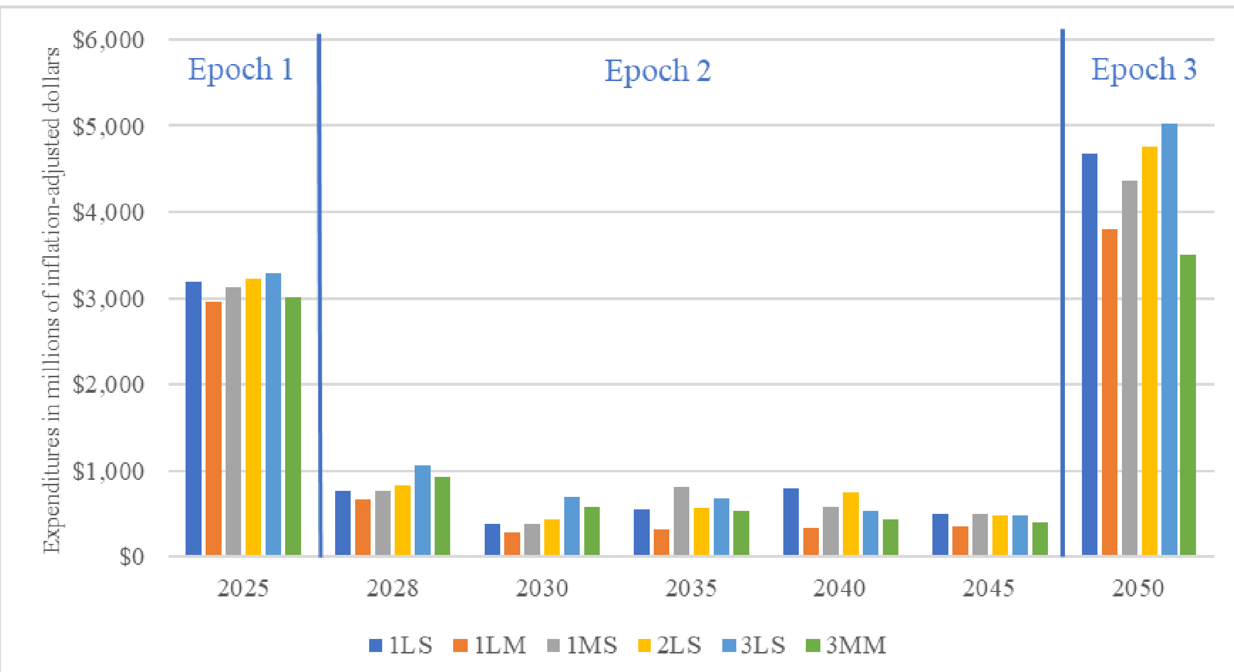


Figure 381. Aggregate regional CapEx and O&M expenditures, select years, in millions of inflation-adjusted dollars

In 2025, aggregate expenditures across the six scenarios are somewhat equal, suggesting that the associated positive economic impacts will be similar within a particular year. For 2050, 1LM and 3MM had considerably lower expenditures than the other scenarios, which played an important role in the simulated economic outcomes reported below. Expenditures in the intermediate years are substantially lower, primarily reflecting (1) expenditures associated with the adoption of new residential and commercial distributed PV and storage and (2) annual O&M.

In Figure 383, we show how each scenario's total expenditures are allocated regionally over the study time frame. The Metro area receives the largest amount, which leads to larger aggregate economic gains due to the new expenditures compared to the other five regions. The East, West, North, South, receive roughly similar amounts of CapEx and O&M, while the Central region receives the least.

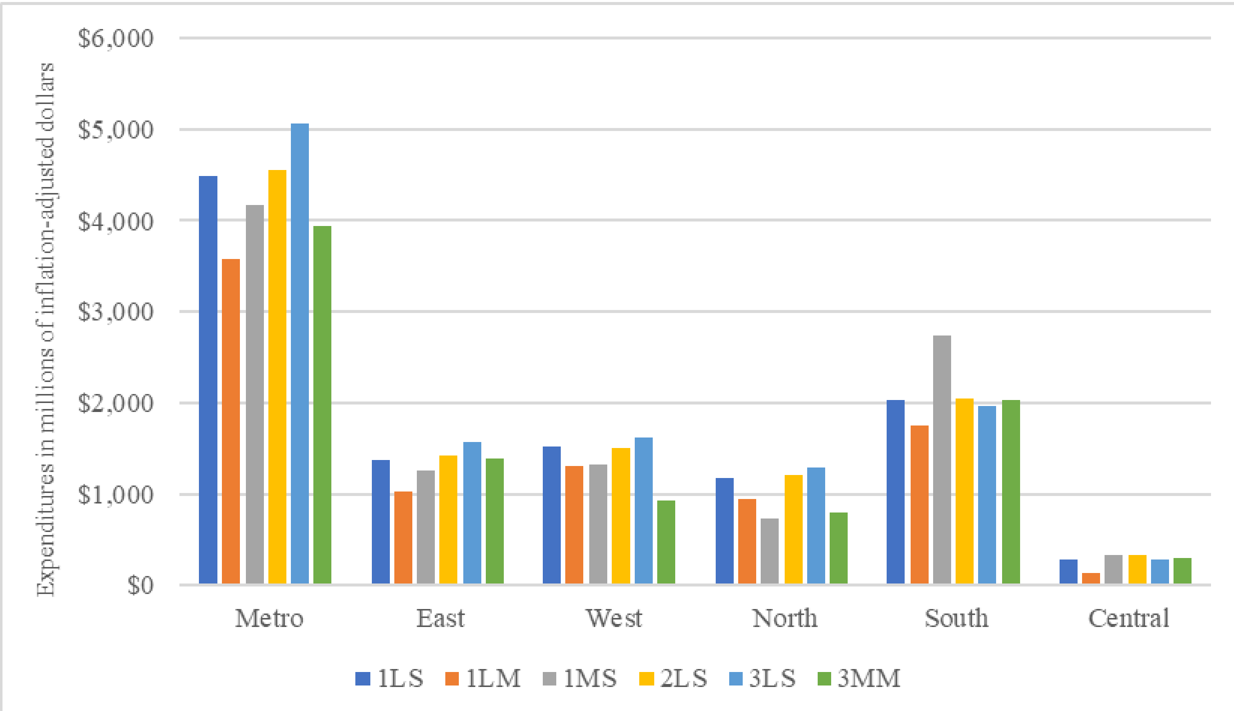


Figure 382. Aggregate regional CapEx and O&M expenditures for each scenario, 2025–2050, in millions of inflation-adjusted dollars

12.3.5.2 Model Inputs: Changes in Electricity Prices

Electricity price increases have two main direct effects. First, they cause households to reallocate money to electricity expenditures and away from other goods and services, reducing household well-being and overall local consumption. Second, they increase local production costs, meaning higher prices for local consumers and a weakening of the competitive position of Puerto Rico's export sectors. Employment losses are an important subsequent impact of these two direct effects, meaning substantial reductions in household income.

Our model considered how electricity price changes between 2022 and 2050 impact three general groups: (1) commercial and industrial customers, (2) moderate- and high-income residential customers, and (3) low-income residential customers. Agents in each group can primarily obtain their electricity through the utility or through the adoption of distributed PV plus storage, with each source having a different effective price trajectory.

To provide a general sense of the price changes considered, Figure 384 shows the trajectory for average utility rates for all customer classes over each scenario. These average rates are described in Section 14.1 and are adjusted for projected inflation per FOMB estimates. Note that these are utility rates and do not include the effective price paid by distributed PV plus storage adopters.

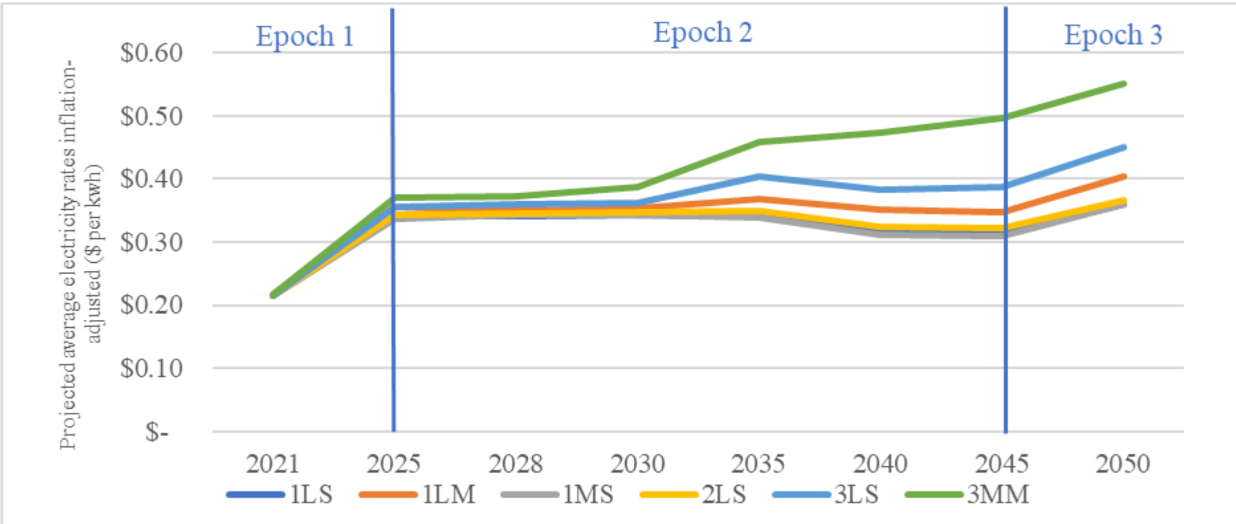


Figure 383. Projected average electricity rates ($ per kwh), all utility customers, select years, inflation-adjusted

As noted above, we considered three unique periods (i.e., epochs) related to the transition. Epoch 1 is the period 2022–2025, which is characterized by significant CapEx investments that will simultaneously meet two goals: (1) increased reliability, resiliency, and capacity of the electric system, bringing it up to industry standard, and (2) allowing Puerto Rico to meet Act 17's 40% renewable requirements by 2050. Note that meeting the first goal will require significant investments independent of meeting the Act 17 requirements. Accordingly, there is a substantial rate increase by that year for each customer class, with average real electricity rates approximately 76% higher than 2021.

Epoch 2 is the period from 2025 to 2045. During this time frame there is less new CapEx expenditure relative to Epoch 1, while the adoption of distributed PV plus storage gradually increases. Note that the annual real rate changes follow a similar trajectory for all scenarios but the 3MM case, with real rates falling for most scenarios from 2035 to 2045. Because real rates tend not to change much during this period for most scenarios, changes in electricity prices should not greatly affect economic activity in Epoch 2.

Epoch 3 considers 2045–2050, the time frame when the last significant CapEx investments are made to meet the 100% renewable mandate of Act 17. Here we once again see real rates increase to finance the additional CapEx expenditure. Details of the specific rate mechanisms for each epoch are provided in Section 12.1.

Like electricity rates, effective electricity prices for distributed PV plus storage adopters will initially increase substantially *relative to 2022*. In contrast to Figure 384, however, the real average price of a kwh for new adopters will gradually decline over the entire timespan. This happens due to falling projected costs of adopting distributed PV plus storage, in accordance with the NREL's ATB. Because repayment schedules are tied to the cost of the system at the time of adoption, the timing of adoption determines the effective price an adopter pays for a kwh: effectively, agents who adopt later will pay lower prices for electricity than earlier adopters. This dynamic meant it is not possible to create a common, graphic descriptive price trajectory for all distributed PV plus storage adopters comparable to the rate trajectory we show in Figure 384.

12.3.5.3 Simulation Results

This section is divided into two parts. First, we estimate the impacts of increases in CapEx and O&M separately from the electricity price increases to understand the unique effects of each on economic activity. To avoid information inundation, we only present simulation results for 1LM and 3LS for 2025 and 2028. This sufficiently illustrates general trends in the differences in price and expenditure effects. Detailed results are in Appendix J.

The second part reports the overall simulation results for all six scenarios for the years 2025, 2028, 2030, 2035, 2040, 2045, and 2050, combining the expenditure and price effects.

Note that when evaluating our results for Epoch 1 it is critical to recognize that while higher electricity price increases will adversely impact customers, they are financing a "better" system than the one that exists today. As noted elsewhere the costs (and associated rate increases) of building a significantly more reliable and resilient electric system would be substantial for Puerto Rico *even in the absence of adopting the specific scenarios we look at in the transition to a 100% renewable electric system*. Thus, we encourage readers to keep in mind that the system in 2025 will be much improved relative to the one that currently exists.

12.3.5.3.1 Disentangling the Unique Impacts of CapEx and O&M and Electricity Price Increases

To demonstrate (and disentangle) the simultaneous positive effects of increased expenditures and negative effects of price increases we first report on separate simulations for each effect for select years and scenarios. We present the estimated employment impacts for 2025 and 2028 for 1LM and 3LS in Figure 385.

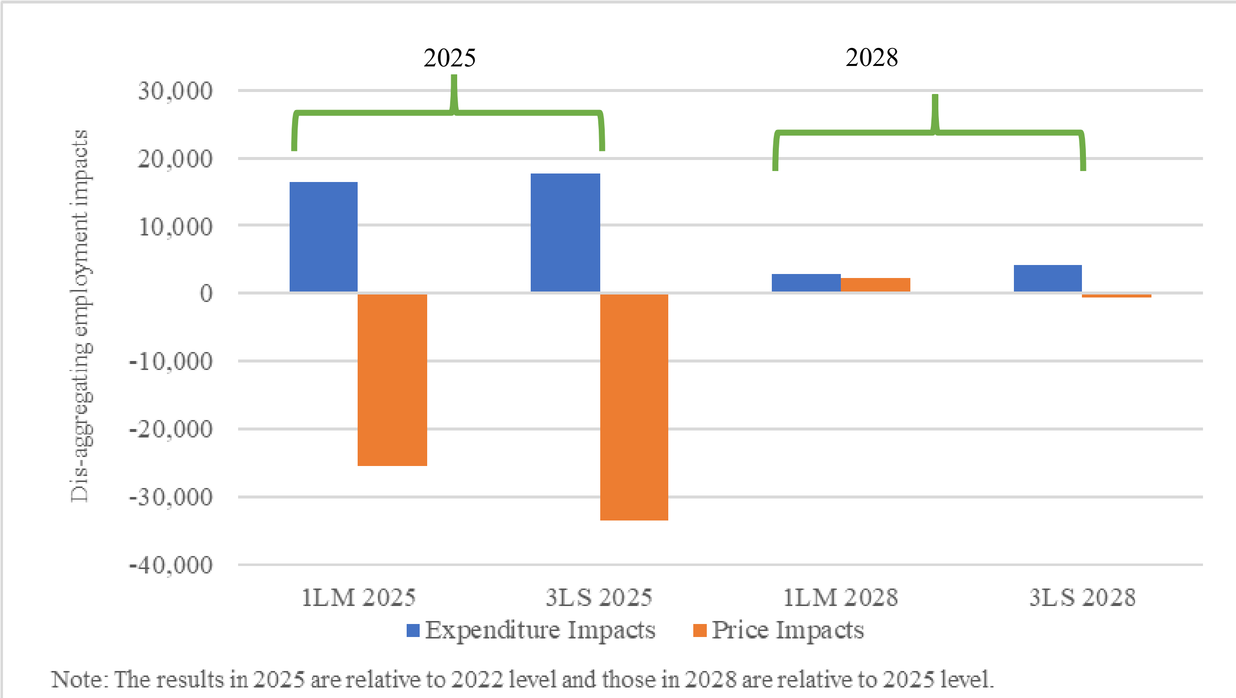
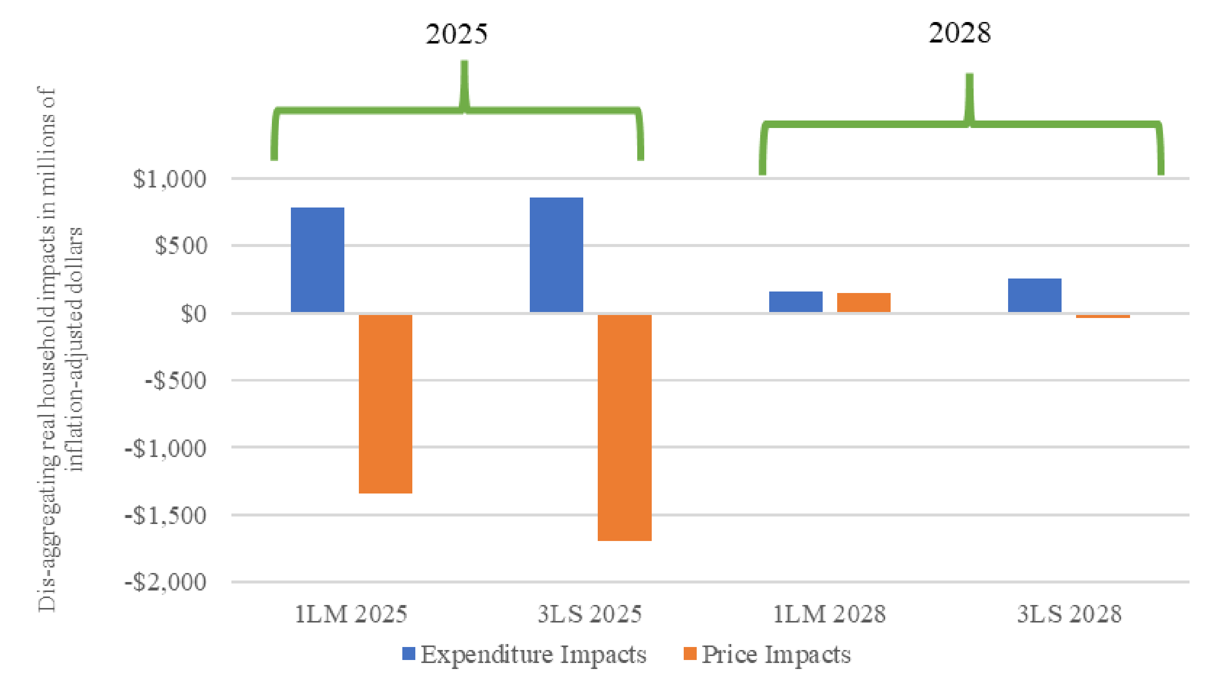


Figure 384. Disaggregating employment impacts due to CapEx O&M expenditures and electricity price changes, select scenarios, 2025 and 2028

Consider first the 1LM case in 2025, a year marked by large CapEx investments and relatively large price increases. The expenditure impacts (shown in blue) indicate that the additional investments needed to meet the 40% goal of Act 17 resulted in more than 16,000 new jobs by that time. These positive impacts, however, were more than offset by the employment losses incurred due to the higher electricity prices (minus 25,000; shown in orange). Turning to 3LS for 2025 we see similar results, showing that the scenarios are not all that different that year. We again stress that the negative price impacts largely reflect investments needed to increase the reliability, resiliency, and capacity of the electric system, rather than anything unique to meeting the goals of Act 17.

Turning to the early years of Epoch 2 (2028), the expenditure and price impacts are much smaller in magnitude than in Epoch 1. This is because there is relatively little new CapEx in this time frame, and electricity price changes are quite small *relative to 2025* (recall Figure 384). It is worth noting that the economy sees a slight positive net impact in 2028—once the "new" electric system infrastructure is in place, the economy begins to see the benefits of relatively small electricity price changes relative to 2025.

A closer examination of changes in real household income provides a nuanced picture that highlights the unique capabilities of the CGE model (Figure 386). We once again considered 1LM and 3LS for 2025 and 2028. In reference to income, employment growth in Epoch 1 from the activity related to the new expenditures lead to substantial increases in wage income, hence household income (plus $782 million; shown in blue). Higher electricity prices, however, lead to a decline in total real household income (minus $1.3 billion; shown in orange).[188] This is due to households seeing an increase in: (1) prices they pay for electricity and (2) increases in the prices of other goods and services as production costs increase. Overall, in 2025 the negative impact of the rate increases results in substantially larger negative aggregate real income effects than the positive impacts of the additional CapEx and O&M expenditures. In summary, for 2025, although some households do benefit from the new jobs created by the CapEx and O&M expenditures, most households in Puerto Rico do not see much benefit; instead, they are adversely affected by the higher electricity prices in the early years. While these adverse effects are substantial, it is important to remember that the 2025 scenario reflects a vastly improved electric system, with more reliability, capacity, and resiliency. These benefits are real and important, but estimating their value is beyond our project's scope.



Note: The results in 2025 are relative to 2022 level and those in 2028 are relative to 2025 level.

Figure 385. Disaggregating real household impacts due to CapEx and O&M expenditures and electricity price changes, select scenarios, 2025 and 2028, in millions of inflation-adjusted dollars

The analysis of 2028 (the start of Epoch 2) tells a much different story. Once Puerto Rico swallows the bitter pill of the price increases needed to build a more reliable and resilient electric system, the movement from 2025 resulted in a small net increase in real household income. This is due to slight income gains associated with the small additional CapEx and O&M expenditures in a time when electricity prices begin to stabilize.

12.3.5.3.2 Simulations for All Six Scenarios: 2025, 2028, 2030, 2035, 2040, 2045, and 2050

In this section we report on analyses that simultaneously consider the impacts of CapEx and O&M expenditures in conjunction with concomitant electricity price increases, looking across all

[188] Recall that real household income (i.e., income adjusted for inflation, or YD/CPI) is the preferred measure when analyzing the effects of price changes in an economy.

six scenarios. Epoch 1 (2025) and Epoch 3 (2050) represent years with the greatest CapEx and O&M expenditures while the intermittent years (Epoch 2) represent relatively low expenditure periods in combination with relatively stable electricity prices.

12.3.5.3.3 Employment and Household Income Impacts

In Figure 387 we present employment changes for each scenario for select years in the three epochs. To provide some context in evaluating these results, recall from Figure 379 (page 480) that Puerto Rico's total employment is slightly less than 1 million jobs. Over the past two years the Commonwealth added about 27,500 jobs per year. Prior to this the economy was struggling, losing about 8,500 jobs per year between 2003 and 2019.

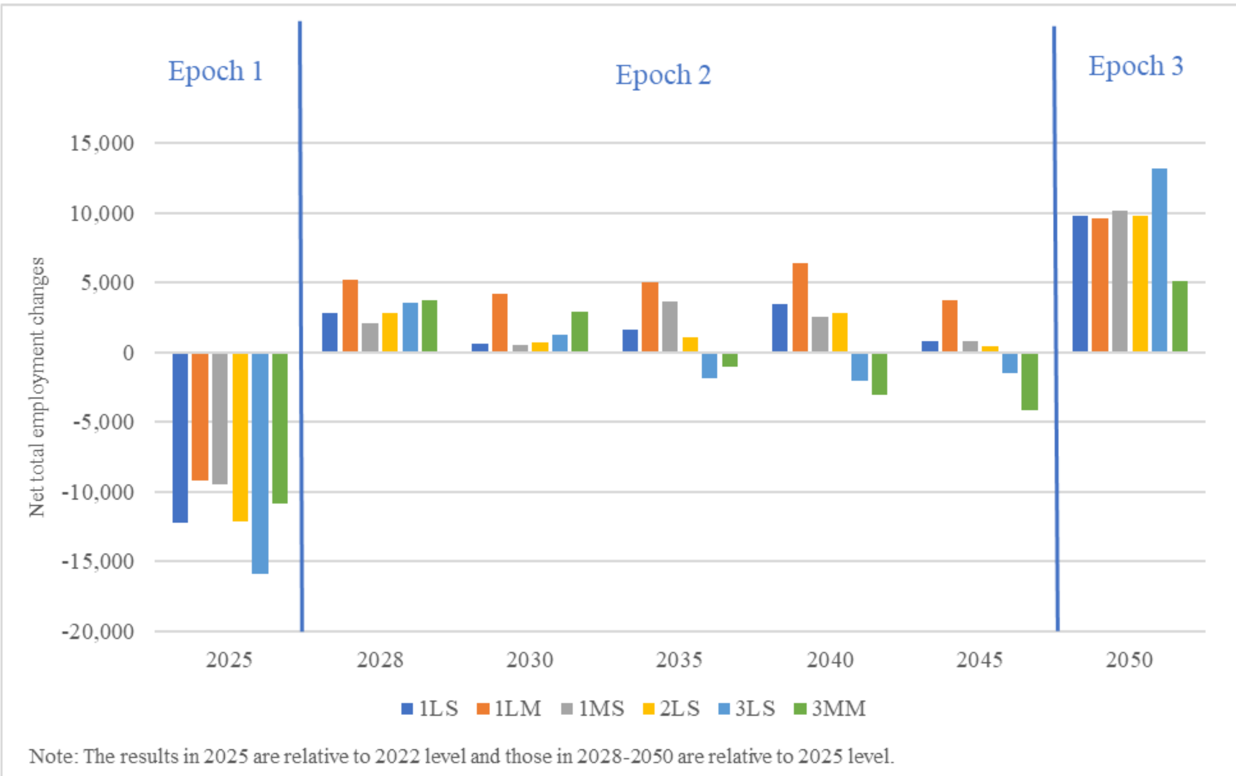


Figure 386. Net total employment changes across scenarios, select years

As shown previously, in 2025 (Epoch 1) there is a net decline in employment across scenarios, with the largest losses in 3LS (minus 15,800), reflecting the scenarios relatively high price increase and slightly lower CapEx expenditures. The smallest losses are in 1LM (minus 9,200).

Beyond 2025, we see a new "state of the world" regarding the resiliency, reliability, and capacity of the Puerto Rico electric system. Thus, we use 2025 as a new reference point for all subsequent simulations.[189] In Epoch 2 (2025–2045) employment impacts are relatively small relative to 2025, reflecting low levels of new spending and small price changes.

[189] As an example, the CapEx and O&M electricity price changes in 2028 are used to compute the economic outcomes that year relative to 2025. For cumulative impacts, employment outcomes should be added to the 2025 result so that the initial large electricity price increase from 2025 is carried through in the subsequent simulations.

The employment impacts are positive across the entire Epoch 2 for the 1LS, 1LM, 1MS, and 2LS scenarios. Beginning in 2035, employment impacts for higher levels of distributed PV adoption (3LS and 3MM) turn slightly negative, reflecting relatively larger electricity price increases. In 2050 (Epoch 3) there are significant positive employment impacts. This reflects higher expenditures as the final investments are made to meet the 100% renewable goals. In this epoch, electricity prices also increase, but by a smaller percentage than in Epoch 1, meaning their effects are less detrimental.

The employment gains in 2028 and up through 2045 start to offset the employment losses that occurred in 2025. As Figure 14.3.9 indicates, the employment gains for each scenario are small for each period in Epoch 2 but by 2050, Epoch 2 and Epoch 3 result in employment gains across the six scenarios.

In Figure 388 we show real household income changes for each scenario over the three epochs. In general, the pattern follows that of employment. In 2025 (Epoch 1) real household income losses range between $580 million (Scenario 1LM) and $864 million (Scenario 3LS). The real household income mechanism for all scenarios in Epoch 1 is that the adverse impacts of associated electricity price increases overwhelm the gains in employment due to the additional CapEx.

By the start of Epoch 2, a more resilient and reliable electric system is largely in place. As a result, there are much smaller net effects on real household income, as electricity price changes and CapEx are both much lower than in Epoch 1. In Epoch 3 (2050) we see positive impacts on real household income across all scenarios. Like employment, these increases are largely due to the stimulative impacts of relatively high aggregate expenditures (Figure 382), which are partially, but not fully offset by the real electricity price increases in that time frame (Figure 384). Like our analysis for employment, it takes up 2050 for the negative impacts from 2025 to be completely offset. Across the six scenarios, the average increase in real household income is $764 million.

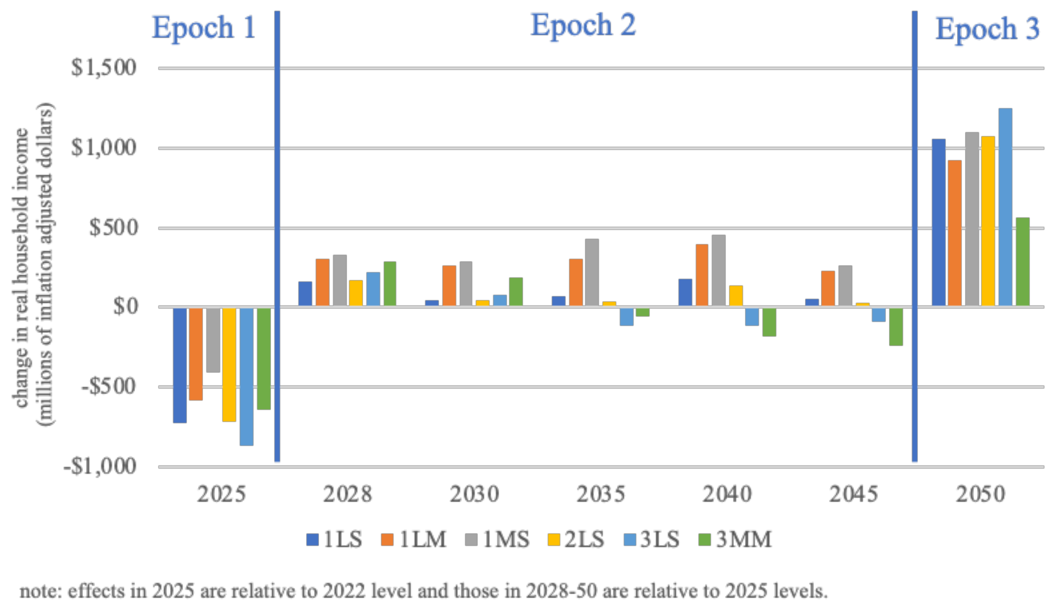


Figure 387. Real household income changes (millions of dollars), over scenarios for all years

12.3.5.3.4 Energy Justice: Income Distribution Impacts

We now turn to the distributional impacts for different household income groups. The CGE model considered six household income groups for each region: <$10k, $10k–$15k, $15k–$25k, $25k-$35k, $35k-$75k, and >$75k and we are interested in how these groups are impacted across scenarios. There are three primary effects on household income. First, increases (decreases) in employment will increase (decrease) wage income and subsequently household income for select households that are affected by labor market changes. Second, changes in electricity prices will affect household purchasing power, with price increases having the effect of lowering real household disposable income, hence making the household worse off. Real price reductions will have the opposite effect. Third, changes in electricity prices affect production costs, with price increases leading to higher costs. Businesses will likely pass on some or all of this cost increase to consumers in terms of higher prices for goods and services (i.e., inflation), making households worse off. Although we do not report specifically on household energy burden (i.e., electricity expenditures as a share of household income), changes in real household income are a good indicator of how household welfare is impacted. We report our analysis for each of the six regions.

For illustrative purposes we examined the 1LM and 3LS cases. These differ in the sense that 1LM is the moderate case with higher levels of utility-scale investments and less distributed PV plus storage adoption. The 3LS scenarios is a "stress case." This also has the highest level of distributed generation. We examined 2025 (Epoch 1) to represent a year where CapEx is high and electricity prices increase substantially. We also examined 2035, which allows us to examine a case with relatively stable electricity prices in conjunction with relatively low levels of CapEx and a reliable and resilient electric system already in place (Epoch 2). The results from other scenarios and other years are provided in Appendix J; the general stories from those scenarios are consistent with the results we present here.

In Figure 389 and Figure 390 we show the 2025 household income distribution results for Scenarios 1LM and 3LS, respectively. Because results vary only slightly across the two scenarios, we focus on overall trends rather than comparative ones. Reflecting the previous results that the negative impacts of higher prices outweigh the positive effects of higher expenditures in Epoch 1 (Figure 386), we show that most household groups in most regions see reductions in real household income. The effects are especially dramatic for the lowest income households, with the two lowest income groups (<$10k and $10k–$15k) experiencing the largest percentage reductions in real household income in both scenarios in 2025. This was expected since these two household groups allocate a relatively large percentage of their budgets to electricity (Table 62). As income increases, the adverse household effects lessen, for two reasons. First, higher-income households spend a smaller share of their overall income on electricity than do lower-income households. Second, because the CapEx expenditures create a significant number of higher paying jobs, many of the income gains due to new job creation accrue to higher-income households, offsetting some of their losses due to higher electricity prices.

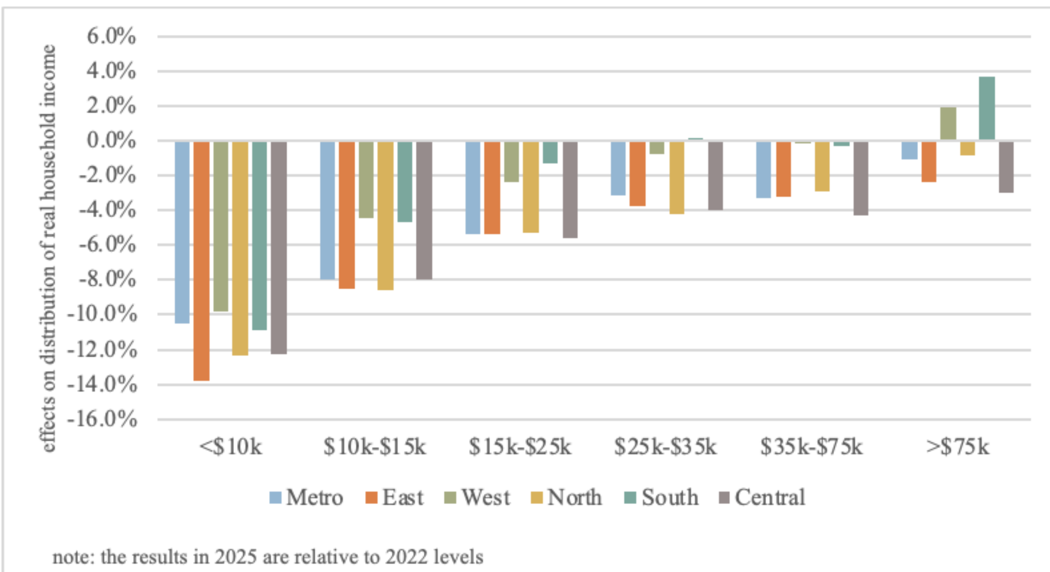


Figure 388. Effects on distribution of real household income, Scenario 1LM, 2025

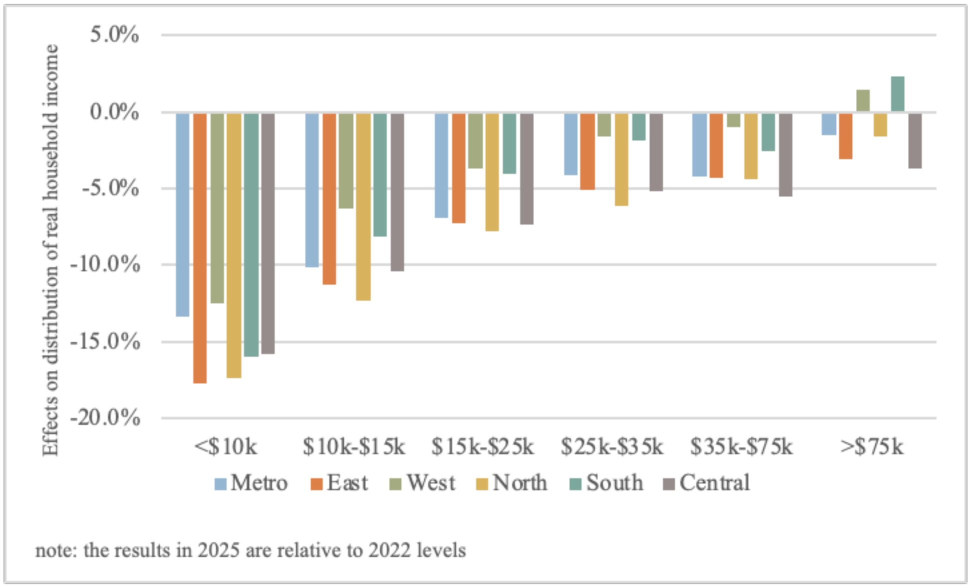


Figure 389. Effects on distribution of real household income, Scenario 3LS, 2025

Turning to 2035—a fairly typical year in Epoch 2—we see some important differences, both relative to 2025 and between scenarios. Considering Scenario 1LM we see *positive* gains in real household income for all income groups (Figure 391). This reflects, in part, stable real electricity rates and declining costs of distributed PV plus storage adoption in conjunction with normal economic growth, per FOMB projections. Thus, once a reliable and resilient electric system is in place, households see slight benefits in Epoch 2 in the 1LM scenario. It is worth noting that lower-income households see some relief from their losses in Epoch 1.

Figure 390. Effects on distribution of real household income, Scenario 1LM, 2035

Simulated results of the distributional impacts for Scenario 3LS show a different story (Figure 392). Recall from Figure 356 (page 444) that electricity rates for this scenario increase more than the scenarios with less distributed PV adoption. The effects are a slight decline in real household income for most income groups, although much less dramatic than in 2025 (Epoch 1). Once again, the lowest income households are most adversely impacted, reflecting their relatively high expenditures on electricity as a share of their income.

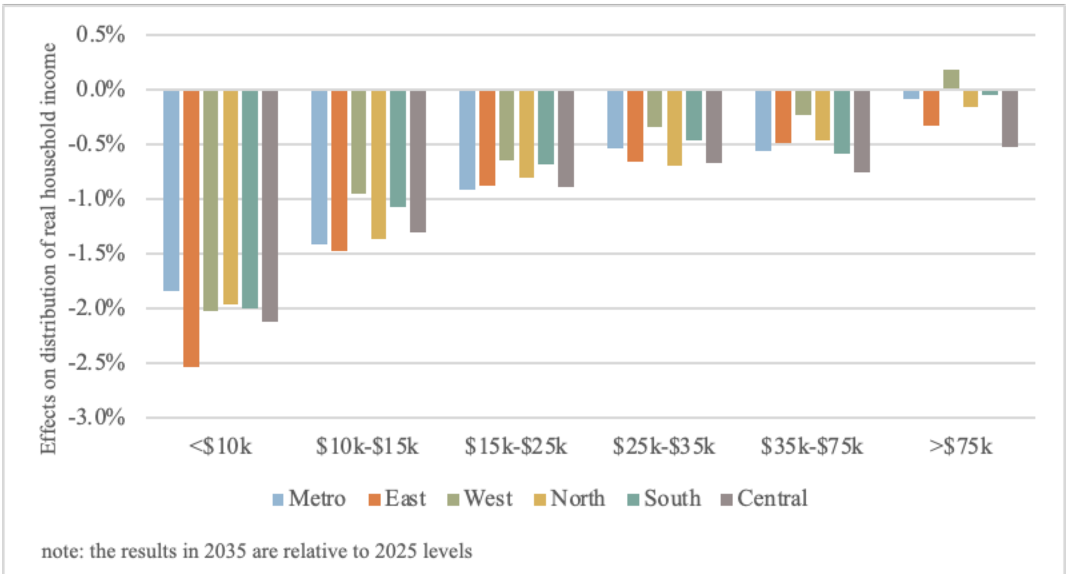


Figure 391. Effects on distribution of real household income, Scenario 3LS, 2035

12.3.6 Discussion

The scenarios we modeled for meeting the goals of PR100 will have significant economic impacts in Puerto Rico. On the plus side, the Commonwealth will see substantial employment and wage growth due to an historic injection of new investment, related to both utility-scale generation, transmission, and distribution, and widespread the adoption of distributed generation and storage. These gains will be notably large in years with substantial amounts of CapEx (e.g., 2025 and 2050); but these are typically short-term impacts, related to construction and installation. Ongoing O&M expenditures, which are much smaller but more persistent, will provide fewer but longer-term employment opportunities.

The scenarios we considered, however, will be expensive for both households and businesses. For customers that rely on the utility, there will be substantial increases in utility rates over time relative to 2022, even after accounting for inflation. For distributed PV plus storage adopters, there are high initial costs associated with purchasing PV and storage, which will lead to adopters also facing higher electricity prices, relative to 2022. These price increases create negative economic impacts through reductions in both employment and real household income.

While the size of the net economic impacts varies across scenarios, we found that the negative economic impacts of the price increases outweigh the positive impacts of the new CapEx and O&M in 2025 in all scenarios. In subsequent time periods, however, losses due to modest increases in electricity prices were more than offset by the positive impacts of CapEx and O&M expenditures. Importantly, we found that low-income households are especially adversely affected, as they spend a relatively large share of their incomes on purchasing electricity, whether from the utility or through their own distributed PV plus storage systems.

These results have some important caveats, however. First, it is essential to acknowledge that our model compares future years to the 2022 Puerto Rico economy. *Other than incorporating inflation, we do not consider how electricity prices would evolve through 2050 under an alternative situation.* For example, if significant new investments are needed to buttress some version of the current system, then rates would likely substantially increase even without a transition to 100% renewables.

It is also important to bear in mind that our analysis only considered a limited set of economic and distributional impacts. While our results show that some PR100 pathways have larger negative economic impacts than others, all should be evaluated in the context of the environmental and health-related economic benefits that accrue under various scenarios. For example, some scenarios may result in larger economic losses, but they may also reduce emissions faster than others, generating other important economic, health, and environmental benefits.

Similarly, our estimates do not consider the value of improvements in resiliency and reliability. If these investments improve the system's functioning relative to 2022, then there are economic gains that are not captured here.

Finally, it is important to recognize that our economic modeling efforts are based on projected trajectories for rates and other costs, both in the short term and the long term. These estimates are subject to uncertainty, such as potential variations in the expected path of technological progress and other associated costs. Additionally, our model sometimes relied on simplifying assumptions, which may not fully represent the nuances of both behavior and the economy. Thus, our results should not be viewed as steadfast predictions, but rather seen as an approximation of what we think will happen, given what we now know.

Policy Considerations

- **Cost Containment:** Our analysis only considered six potential scenarios, and there are many other potential ways Puerto Rico can meet the requirements of PR100. Our general findings, however, suggest that any pathway that results in significant electricity price increases will likely slow down economic activity. Thus, an important part of any planning process should consider cost-containment policies or subsidies at both the utility-scale and for distributed systems.
- **Energy Justice:** Our findings (and previous research) show that lower-income households are especially vulnerable to higher electricity prices. They also may have a more difficult time adopting distributed PV plus storage due to higher up-front costs and potential difficulties in arranging financing. If equity is a concern, special consideration should be given to ease the effects on lower-income residents.
- **Economic Development:** The transition to PR100 will involve significant capital expenditure. In practice, however, much of the equipment and materials (e.g., solar panels and wind turbines) will likely be produced somewhere other than Puerto Rico. Therefore, much of the associated economic impact will occur elsewhere. Although larger forces shape the location decisions of critical input manufacturers, policymakers looking to increase positive local impacts may want to identify potential opportunities for producing needed inputs in Puerto Rico.

- **Workforce Development:** Even if most inputs are imported, the additional CapEx will still lead to substantial increases in local labor demand in some sectors, including site preparers, construction workers, line technicians, solar panel installers, and maintenance workers. These jobs are often high-paying, and their creation may help stem the long-term trend of out-migration from Puerto Rico. However, some of the new jobs may require workers to possess skills they do not currently have. Accordingly, Puerto Rico may want to develop and implement appropriate workforce development programs to help maximize local benefits.

13 Climate Modeling and Risk Assessment

John T. Murphy[1], Jiali Wang,[1] Susan Jones,[1,] and Lawrence Paul Lewis[1]

[1] Argonne National Laboratory

Section Summary

We undertook climate modeling in PR100 to assemble state-of-the-art projections for Puerto Rico's climate at mid-century (2050). We present results in Section 13.4; these include changes in temperature (Section 13.4.1), precipitation (Section 13.4.2), and solar radiation and wind (Section 13.4.3); these results are summarized for various regions in Puerto Rico in Section 13.4.4. Energy justice implications of a changing climate are discussed in Section 13.3. Simulation methods are given in Section 13.2; detailed discussion of output data and of data handling are given in Appendix K and Appendix L. This section focuses exclusively on how a changing climate will affect the transition to renewable energy and the infrastructure that will support it; a collection of considerations about future climate modeling work and the expected impacts of the projected changes are given in Section 13.5 (page 537). This section does not address in detail many other aspects of Puerto Rico's changing climate or impacts beyond renewable energy infrastructure. For more information on these, see the *Fifth National Climate Assessment* (USGCRP 2023).

Key Findings

- Temperatures are projected to increase from baseline (circa year 2000) to mid-century (circa 2045). Increases in daily mean, daily minimum (overnight low) and daily maximum temperatures will vary by region and by season. Daily minimum temperatures increase slightly more than daily means and maxima; the increase is most notable in spring (magnitude = ≈3° F).
- In other studies, precipitation has been projected to decrease generally. Our simulations indicate that dry periods will become drier, but wet periods may also become wetter, carrying multiple kinds of risks at different times of the year, for different regions.
- Solar radiation may see slight decreases in most areas and in most times of the year. Maximum daily winds will generally decrease in most areas and seasons, increasing in a few regions in winter but generally showing little change in timing (daily, seasonal) or direction.
- Qualitative changes are already being experienced, and incidents of extreme events can be expected to continue and happen more frequently.
- Rising temperatures will increase overall electricity demands, reduce transmission capacity, and require energy infrastructure operators to manage strains on system components that are exposed to higher daily heat stress.
- Energy infrastructure situated along coasts and inland waterways will face climate-driven risks of increased flooding and washouts.
- Vulnerabilities of energy infrastructure will be exacerbated by climate-driven risks in ways that may lead to premature obsolescence of those assets.

Considerations

- Climate-driven impacts on infrastructure, including premature obsolescence due to exacerbated and extreme conditions, must be accounted for.
- Additional modeling and the use of alternative modeling scenarios can improve the utility of the form of modeling employed.

13.1 Introduction

At the release of this report, the U.S. government has just released the initial portions of the *Fifth National Climate Assessment* (USGCRP 2023). The comprehensive report inventories the risks posed to the entire United States, and includes a chapter on the U.S. Caribbean, including Puerto Rico and the U.S. Virgin Islands (Méndez-Lazaro et al. 2023). The report also relates a set of key messages and findings that encompass many anticipated climate challenges and their impacts on many, if not all, aspects of life in this region.

Although more limited in scope than the National Climate Assessment, this section on climate modeling and risk assessment offers a different and complementary view. Whereas the National Climate Assessment provides an overview of how a changing climate will impact many aspects of Puerto Rico's future, this section focuses on the impacts on the anticipated renewable energy infrastructure. It also focuses on a set of recent, state-of-the-art climate simulations that were undertaken at a fine-scale resolution (4 km) and provide a new window into how a changing climate will affect specific areas in the Commonwealth. The data set will be made available as part of the PR100 web-based resources,[190] and this section provides a guide to its initial results. In accord with our commitment to procedural justice, the intent of this section is to place the data in the hands of the people of Puerto Rico as they chart their self-determined energy future.

Key findings from our climate modeling and risk assessment work are:

> **Key Finding:** Temperatures are projected to increase from baseline to mid-century. Increases in daily mean, daily minimum (overnight low), and daily maximum temperatures will vary by region and by season. Daily minimum temperatures increase slightly more than daily means and maxima; the increase is most notable in spring (magnitude = ≈3° F).

Temperature increases can be expected in line with a warming planet. Puerto Rico is not generally affected by cool temperatures, and these are not analyzed for this report. Hotter temperatures can be measured in several ways:

- Average daily mean temperature
- Average daily maximum temperature
- Average daily minimum temperature
- Cooling degree days
- Days above 90° F.

These have different implications. Daily maximum temperature indicates the maximum stress that heat imposes on both people and infrastructure. Daily minimum temperature, usually corresponding to the overnight low, indicates relief from these daytime stresses and lessened demands for cooling during nighttime. Daily mean temperature is usually calculated for station data as the average of the daily maximum and daily minimum and provides an intuitive summary of individuals' daily experience of these high and low temperatures.

A standard proxy for understanding the demand on the energy system related to keeping people and equipment cool (U.S. Energy Information Agency 2023) is cooling degree days; these are

[190] http://www.pr100.gov/

calculated as the sum across days of the differences between each day's mean temperature and 65° (values less than 65° ignored). For example, three days with mean temperatures of 70°F, 75°F, and 50°F, result in (70 – 65 = 5, 75 – 65 = 10, and 5 + 10 = 15 cooling degree days, and the third day is ignored because it is below 65°F.) Another commonly used measure is the count of days above 90°, which also indicates temperature in an intuitive and statistically comparable way.

On all these measures, simulation results show increases in Puerto Rico from the baseline simulation period to the projection period. Daily minimum temperatures increase somewhat more than mean and maximum temperatures, indicating less overnight relief from daytime highs and implying a possibly shift in the schedule for electrical cooling demand.

As with all results, the magnitude of the increases varies by region and by season; these details are discussed more fully in the results (Section 13.4, page 516).

Key Finding: In other studies, precipitation has been projected to decrease generally. Our simulations indicate that dry periods will become drier, but wet periods may also become wetter, carrying multiple kinds of risks at different times of the year, for different regions.

Simulation of precipitation is inherently more subject to error than simulation of temperature. One study in 2009 found that, "[t]he agreement among climate model simulations on the spatial distribution of time mean precipitation changes tends to be very poor, especially at a regional scale" (Chou et al. 2009, 1983). The same study proposed that mechanisms that lead to precipitation in the complex topographical and atmospheric context of tropical islands like Puerto Rico were not fully understood, and simulation approaches have difficulty reflecting the real-world dynamics. More recent studies (Villamil-Otero et al. 2015) have continued to try to refine the methods for modeling precipitation in these contexts. Consequently, simulation of precipitation is more challenging and should be considered more uncertain than other climate variables.

Previous studies, including the 2018 National Climate Assessment (USGCRP 2018; Reidmiller et al. 2018), have suggested precipitation declines across Puerto Rico by mid-century, in some cases reaching decreases of 20% from baseline values. These studies have focused on total annual rainfall, though some (Terando 2017) examine intrayear periods and arrive at the same conclusions.

Our simulations suggested that precipitation will increase in many areas and for some parts of the year; some regions of Puerto Rico, this may result in an increase in the overall annual total. This does not mean that all areas will see increases, nor that there will not be times of the year that receive less rainfall. Generally, the pattern will be that dry periods get drier, and wet periods get wetter. This increase in the extremes carries multiple kinds of risks.

Key Finding: Solar radiation may see slight decreases in most areas and in most times of the year, with only a few areas and times of the year seeing increases. Wind is expected to change little either in strength or timing (daily/nightly or seasonal) but may also include higher extreme values in some areas in winter.

Our examination of solar radiation and wind showed only very slight differences between the baseline and projection periods. Solar radiation is determined primarily by three factors: the position of the sun (and hence is zero at night, increases before noon and decreases after noon until sunset); the time of year (whether the sun's rays are more vertical, as during summer); and cloud cover. Deflections from maximum that differ from baseline to projection are likely attributable to cloud cover. However, the difference is comparatively slight. Decreases as high as 6% may be seen in some regions in the summer; decreases are smaller in other seasons, and some areas see increases in the fall (up to 2%).

Average wind speeds decline in general, in all regions and seasons. But winter in many regions exhibits higher maximum wind speeds. We note that the alignment of wind and solar radiation continues: Wind is stronger mainly during daylight hours, and therefore at the same time solar radiation is available and diminishes in the evenings. Were these not aligned, solar power generation could be used during the day and wind power at night, but because they are both available mainly during the day (especially afternoons), another strategy is required.

Key Finding: Qualitative changes already being experienced, and incidents of extreme events, can be expected to continue and happen more frequently.

Previous discussions have highlighted the increasing likelihood of extreme events such as periods of high temperatures or droughts, the increasing frequency and intensity of storms, and the increasing likelihood of the hazards (e.g., flooding and wildfire) of these changes. The simulations presented here may contain indicators of these, but the analyses to discern each of them is out of scope. However, nothing in our analyses precludes or contradicts these changes. Hence, the current trends that have become apparent in the last two decades, and especially so in recent years, can be expected to continue. Planning should take these into account.

Key Finding: Rising temperatures will increase overall electricity demands, reduce transmission capacity, and require energy infrastructure operators to manage strains on system components that are exposed to higher daily heat stress.

Rising temperatures will likely increase peak electricity demands across every season and every region in Puerto Rico. In responding to higher daily minimum, maximum, and mean temperatures, increased air conditioning and other cooling systems will result in a corresponding increase in electricity consumption. Several complementary climate projection studies have estimated that household energy demands may rise by over 25% across the Caribbean (van Ruijven et al. 2019). As these increases are observed in demand, rising temperatures will also affect supply at both generation sources and throughout transmission.

- **Generation Sources that Depend on Cooling Systems:** Components of generation and storage that require cooling (e.g., wind turbines and batteries) will be under even greater heat stress by mid-century, increasing overall needs for cooling and, therefore, their own electric power dependencies (Fuskele et al. 2022).

- **Carrying Capacity of Aerial Power Lines:** Components of transmission and distribution systems (e.g., aerial power lines) will be affected by rising ambient temperature that will reduce their carrying capacity, leading to load shedding and, potentially, degraded or disrupted operations in a service area (Bartos et al. 2016).

Rising daily minimum, maximum, and mean temperatures will have these and other indirect impacts on demand, capacity, and operational requirements. The overall trend will be toward increased demand and strained supply across communities and the energy systems that support them. This will require infrastructure planners to account for the projected fluctuations in minimum, max, and mean temperatures that may be observed throughout the days of each season/region, which may affect demand, capacity, and operational requirements.

Key Finding: Energy infrastructure situated along coasts and inland waterways will face climate-driven risks of increased flooding and washouts.

A significant amount of the generation capacity is currently installed near coastlines, where chronic sea level rise and acute events such as storm surge leading to coastal flooding create significant risks for the electric grid. Energy infrastructure located along or crossing inland waterways (e.g., power lines colocated with road bridges) is vulnerable to washouts from increased flooding risks where precipitation is increasing, particularly in rural regions.

New infrastructure that changes land use, particularly in combination with higher intensity rainfall, will also create greater potential for erosion and water management challenges. This may lead to a need for significant environmental impact assessments to identify potential water management challenges and to ensure changes to land use do not create new risks that will be exacerbated by increasing precipitation.

Key Finding: Vulnerabilities of energy infrastructure will be exacerbated by climate-driven risks in ways that may lead to premature obsolescence of those assets.

The lifespan of infrastructure assets is determined by the capability of the infrastructure, from its initial planning and subsequent management/maintenance, to withstand future conditions that may not have existed at the time of its initial design and construction. The expected lifespan of infrastructure that is not designed and constructed with climate change adaptation (as well as broader hazard mitigation) in mind will be at risk of becoming prematurely obsolescent in terms of its ability to fulfill its operational requirements as part of the system and meet the service demands of downstream users.

The level of investment that will be required in the renewable energy transition for Puerto Rico necessitates climate-cognizant planning and design in order to ensure new infrastructures are adapted to future climate conditions and to maximize the potential lifespan of energy infrastructure.

Climate-cognizant planning and design will be critical to adapting to future climate conditions. Although climate-cognizant infrastructure may require higher upfront costs, investments should incorporate those solutions that are most efficient and pragmatic to meeting the desired lifespan of the infrastructure in light of climate-driven risks. The management of energy infrastructure should include monitoring systems to understand how climate conditions throughout days, between seasons, and across regions may create new risks to the reliable and resilient operation of the infrastructure. Downscaled climate modeling should inform infrastructure investment, design, and management decision-making in order to ensure the siting and operational requirements are informed by climate projections.

13.2 Methodology

13.2.1 Dynamical Downscaling

Downscaling is a process by which the resolution of a climate data set is increased from coarse to fine. Dynamical Downscaling, the method used for this study, is differentiated from statistical downscaling. Statistical downscaling generates high-resolution results from low-resolution data by using mathematical shortcuts that are based on observed data series. Dynamical downscaling uses physics-based approaches that simulate the small-scale atmospheric processes using the coarse-scale data as boundary conditions. Dynamical downscaling is computationally more expensive, but overcomes some of the limitations of statistical approaches (Kotamarthi et al. 2021).

PR100 used data that are part of the Argonne Downscaled Data Archive (ADDA) v2. ADDA v1 was created covering the continent of North America at 12-km spatial resolution, and has been validated extensively (J. Wang and Kotamarthi 2014; 2015; Zobel et al. 2017). Validation of ADDA v2 is in progress (Akinsanola et al. 2023); ADDA v2 is at a finer spatial resolution, with a grid interval of 4 km (16 km^2/grid cell). The original data set that was downscaled included results from general circulation models, in which resolution was so coarse that Puerto Rico in its entirety would include one or two modeled data points; by contrast, the ADDA v2 data set at 4-km resolution provides hundreds of data points across the archipelago.

13.2.2 Weather Research and Forecasting Data Inventory

The model used to perform the dynamical downscaling is the Weather Research and Forecasting (WRF) toolkit (Skamarock et al. 2021). Because it uses a physics-based approach, it simulates a set of variables that must be adequate to capture all the physical processes that govern the movements of air and water in the atmosphere and that give rise to winds, precipitation, cloud cover, et cetera. WRF tracks dozens of variables, including such elements as temperature, pressure, wind speed, water content, and solar irradiance. Often these variables are maintained not only for a single point near the earth's surface representing the latitude and longitude of a grid cell, but for multiple layers of the atmosphere at various altitudes extending upward from the ground.

Our analysis focused on four key variables:

- Air temperature at 2 m above the ground, also called near surface temperature or ambient temperature
- Precipitation (in Puerto Rico, this was exclusively rainfall, but included convective and non-convective)

- Downward solar irradiance (maximum determined by the position of the sun, deflection to values less than maximum indicating cloud cover)
- Wind (evaluated as two orthogonal vectors giving wind speed and direction).

13.2.3 Time Periods Evaluated: Baseline Versus Mid-Century

The simulations were intended to detect trends in these climate variables by establishing a baseline period that could be compared to historical data and comparing the values in the baseline to a projected period in the future. Baseline simulations were performed for 1994–2004, with 1994 considered a "burn-in" year, a year in which the simulation could stabilize from its initial state and generate results that were used for 1995, which became the first year used for analysis. This historical baseline was then validated by comparison with actual historical data.

The mid-century projections included the years 2041–2050, with 2040 being simulated as the burn-in year and discarded from the analysis.

13.2.4 Temporal and Spatial Resolution

The WRF simulation runs at a nominal time-step of 10 to 15 seconds, and outputs results for all variables at an hourly interval, for each grid cell. The North America data set represented a grid of 2,049 x 1,749 grid cells, amounting to over 3 million individual spatial locations. Given 90+ variables, 8,760 (or 8,784) hours/year, and 10-yr periods, the total output could reach hundreds of terabytes.

Puerto Rico was encompassed by a subset of this, a grid of 56 x 61 cells, of which more than 600 are over Puerto Rico's land area. Even this fraction of the data was large enough to pose data management challenges. However, the difficulty managing data was more than justified by the improved spatial resolution. Because the grid cells are at positions separated by roughly 4 km, the spatial resolution achieved is fine enough to see the impacts of local topography (coastal areas at sea level versus Inland areas at much higher elevation), and to gain a richer window into the climatic variation that exists across the archipelago, and how a changing climate will affect each region differently.

13.2.5 Data Analysis

For temperature, precipitation, and solar radiation, numerical analysis was performed by:

- Calculating the max, min, and mean using the 24 hourly values throughout the simulation day. For temperature, this is at variance with common practice for station-based analyses, which calculate the mean daily temperature by taking the simple average of the maximum and minimum daily temperatures. For precipitation and solar radiation, more typically the sum of the day's values would be used to obtain total daily precipitation and total wattage of solar radiation, but dividing this sum by 24 does not affect the results meaningfully.
- Calculating the mean of these values across seasons, using:
    - December–February = winter
    - March–May = spring

- June–August = summer
- September–November = fall.

- Averaging these values across all years within the baseline and mid-century projection periods

Differences were then calculated by subtracting the baseline from the mid-century values. Some variations that deviated from this were performed due to data issues; see Appendix L for details. The full data set that will be made available also includes data aggregated by month instead of by season, but only seasonal analyses are discussed in this report.

A limited number of other special-purpose analyses were produced and described in the results section below.

13.2.6 Input Data

The following input data were used for the climate simulations:

- The results of a previously run general circulation model were used as the coarse base data for the dynamical downscaling; the model used was CESM 2, with a resolution of 0.9 degrees latitude and 1.25 degrees longitude, from the CMIP 6 archive (Danabasoglu et al. 2020).
- Land use categories were kept constant across all simulation years and both baseline and projection periods; the possible land use changes within each period, and between the baseline and future projection periods, are not considered. Land use categories are from Moderate Resolution Imaging Spectroradiometer (MODIS) IGBP 21-category data (Broxton et al. 2014), and the topography data are from USGS GTOPO30 (USGS 1999).
- The trajectory of greenhouse gas emissions during the projection period was provided by Shared Socioeconomic Pathway 5 (SSP5). This is one of a set of standard future projected emissions trajectories. It is descended from Representative Concentration Pathway (RCP) 8.5, which is sometimes referred to as the business-as-usual case in that it reflects no strong deflection away from current trends in greenhouse gas emissions. This is misleading, because it reflects one of the least likely future trajectories; indeed, in the later years of the pathway (i.e., end-of-century, and hence beyond the use here for PR100), the greenhouse gas emissions in this scenario would be almost impossible to achieve in reality, with the assumed rate of consumption of fossil fuels exceeding the likely global supply. Consequently, this SSP is an aggressive warming scenario, but not necessarily the most likely future (Hausfather and Peters 2020).

As indicated above, we use seasons of December–February = winter, et cetera, but we note here that this is appropriate for measuring changes in the values of climate variables but imposes a limitation in understanding the timing of yearly climate events. For example, if the baseline summer is high in precipitation while spring is low, but the projections show spring increasing and summer decreasing, it may be the case that precipitation is simply occurring earlier, moving across the May/June boundary. This change may be very important for some kinds of purposes (e.g., an agricultural season), but less so for others (e.g., designing a water management system based on flow capacity needed, which is actually unchanged).

13.3 Energy Justice Integration and Implications

The climate simulations reviewed here were performed for the entire North American continent and are driven by physics-based processes that include little role for human activity. Human activity can be said to impact the simulations primarily in the assumed curve of greenhouse gas emissions over time (e.g., whether emissions peak and then decline or keep increasing) and in the existence of land use classes (e.g., urban areas that impact local climate dynamics by creating heat islands). However, the simulations do not permit feedback between the climate system and these human inputs, so that the curve of emissions is assumed and used as a driver for the simulation, and the land use category ascribed to every ground surface point is, in the absence of a better method, assumed to be constant through the entire period of the simulation.

Consequently, linking these technical details to issues of energy justice is difficult. Conversely, the motivation and the results of these simulations have clear implications for environmental and energy justice: the simulations are being performed in order to understand how the climate will affect specific communities, the lives of the people in them, and the challenges to and impacts on the energy system that serves them.

With respect to the renewable energy system, these energy justice implications are clear, and are related to all of the pillars of energy justice:

- **Procedural Justice:** Better understanding of the patterns of a changing climate across the archipelago can permit fuller participation in the discussions of the design and operation of the energy system. This understanding should be commonly available to all stakeholders, motivating the distribution of this climate data as widely as possible.
- **Distributive Justice:** The impacts of a changing climate will affect different regions and different groups of people within those regions in multiple ways. The energy system that is operated within this changing climate, and that must respond to demands that are affected by while facing direct challenges from it, will inevitably risk distributing its benefits and burdens inequitably. Better forecasts of the climate future can permit better discussions of these inequities and better plans for ameliorating these.
- **Recognition Justice:** A local-level view of climate impacts can permit stakeholders to identify local concerns and to specify how the climate conditions affect their interests in energy infrastructure (including quantity of demand, various uses, and challenges to infrastructure).
- **Restorative Justice:** Both energy inequities and the inequities caused by a changing climate have impacted some populations more than others; these two causes may also combine. A fuller discussion of this than is possible here is found in the most recent National Climate Assessment (USGCRP 2023). The design and operation of the future energy system can incorporate an understanding of climate challenges to avoid recapitulating and remedy past injustices.
- **Transformative Justice:** Ultimately the new renewable energy infrastructure should allow a more distributed structure for making decisions, echoing the tighter resolution of our simulations and driven by the points of view and interests of local- and community-level management structures.

13.4 Results

For detailed analysis, Puerto Rico was divided into multiple subregions. With the intent to capture ecological, topographical, and climatic zones, the regional division was based on a classification from National Oceanographic and Atmospheric Administration (Gómez-Gómez, Rodríguez-Martínez, and Santiago 2014; NOAA 1982). The original image and the division that we used are illustrated in Figure 393 and Figure 394. Note that this is only a convenience, and that while ideally the divisions would align with clearly defined climatic zones, in practice significant changes may cross these boundaries in arbitrary ways, blurring the distinctions that we would hope to capture. The full data will be available online and will allow users to explore areas in other ways, including by municipality.

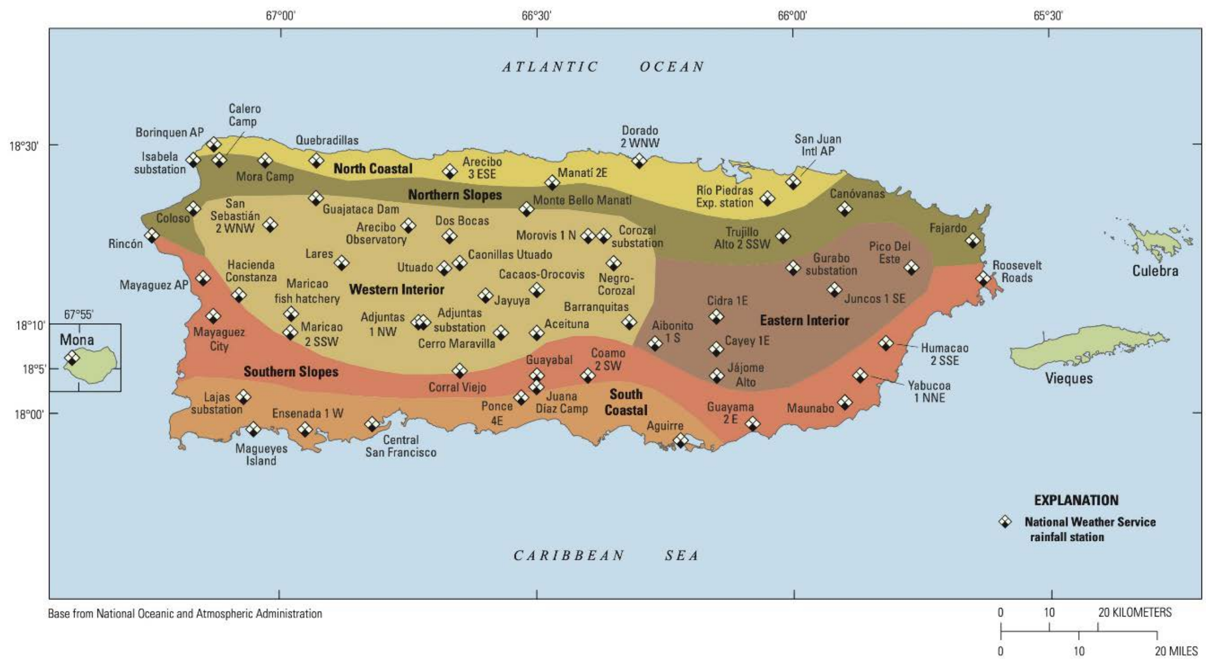


Figure 392. NOAA regional division into climatic zones

Public domain image from Gómez-Gómez, Rodríguez-Martínez, and Santiago (2014)
Base map from the NOAA (1982)

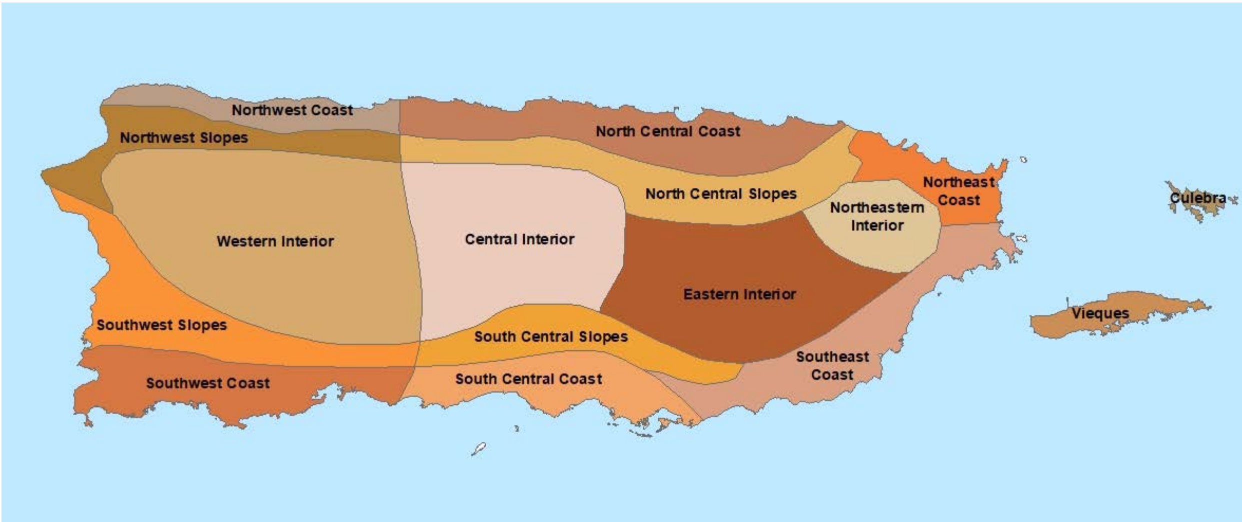


Figure 393. The further division into subregions used here

Image created by Susan Jones, Argonne National Laboratory

13.4.1 Increasing Temperatures

Generally, the main island of Puerto Rico will see increasing temperatures in all seasons. This includes increasing daily mean temperatures as well as increasing daily minimum and maximum temperatures. Daily minimum temperatures increase slightly more than daily mean or daily maximum temperatures, indicating that, while days get warmer overall from baseline to projection periods, a significant part of the warming is because the nights do not cool as much.

The most extreme temperature increases will occur in the spring and extend into summer. Increases occur in fall and winter, but to a lesser extent. Table 63 lists these changes, beginning with spring and proceeding through the year. Note that calculation of mean temperature for our simulation results differs from calculations from station readings: station readings often record only the daily maximum and minimum and calculate daily mean by averaging these two values. For simulation data, we have hours values, and we calculate the daily mean by averaging all 24 temperatures recorded for the day.

Table 63. Average Increase in Mean Daily Temperature (°F) by Region, Baseline to Projection Period

Region	Spring	Summer	Fall	Winter
Central_Interior	2.9	2.7	2.7	2.6
Culebra	2.8	2.4	2.5	2.3
Eastern_Interior	2.8	2.6	2.7	2.6
North_Central_Coast	2.9	2.6	2.7	2.7
North_Central_Slopes	2.9	2.6	2.7	2.7
Northeast_Coast	2.8	2.5	2.7	2.5
Northeastern_Interior	2.8	2.5	2.6	2.5
Northwest_Coast	3.1	2.8	2.8	2.8

Region	Spring	Summer	Fall	Winter
Northwest_Slopes	3.2	2.9	2.8	2.7
South_Central_Coast	2.8	2.5	2.7	2.5
South_Central_Slopes	2.8	2.6	2.7	2.5
Southeast_Coast	2.8	2.5	2.7	2.4
Southwest_Coast	2.8	2.5	2.8	2.6
Southwest_Slopes	2.9	2.6	2.8	2.6
Vieques	2.8	2.5	2.7	2.4
Western_Interior	3.0	2.9	2.8	2.7

Figure K-1 (page 754) through Figure K-4 (page 755) in Appendix K show the maps of these temperature differences across the landscape. The highest increases are in the spring in the Northwest Slopes, Northwest Coast, and Western Interior.

Much of the increase in mean temperature is due to the increase in the minimum daily temperature (overnight low), rather than the maximum temperature. Table 64 summarizes these changes.

Table 64. Increases in Daily Minimum Temperatures (°F) by Region and Season, Baseline to Projection Periods

Region	Spring	Summer	Fall	Winter
Central_Interior	3.0	2.8	2.8	2.8
Culebra	2.8	2.3	2.6	2.2
Eastern_Interior	3.1	2.8	2.9	2.9
North_Central_Coast	3.1	2.8	2.7	2.9
North_Central_Slopes	3.1	2.9	2.8	2.9
Northeast_Coast	3.0	2.7	2.8	2.6
Northeastern_Interior	3.0	2.7	2.8	2.7
Northwest_Coast	3.2	3.0	2.8	3.1
Northwest_Slopes	3.2	3.0	2.7	2.9
South_Central_Coast	3.0	2.7	2.9	2.8
South_Central_Slopes	2.9	2.7	2.7	2.7
Southeast_Coast	3.0	2.7	2.9	2.6
Southwest_Coast	3.2	2.8	3.0	3.0
Southwest_Slopes	3.0	2.8	2.8	2.9
Vieques	3.0	2.5	2.9	2.5
Western_Interior	3.1	2.9	2.8	2.9

Figure K-5 (page 756) through Figure K-8 (page 757) in Appendix K display these differences in the minimum temperatures as GIS data.

These regions will also differ in cooling degree days; these differences are summarized in Table 65.

Table 65. Cooling Degree Days, Average Differences per Region Projection versus Baseline

Region	Spring	Summer	Fall	Winter
Central_Interior	261.3	246.8	259.9	231.3
Culebra	253.7	219.8	267.4	208.7
Eastern_Interior	260.2	236.5	266.9	233.2
North_Central_Coast	267.3	239.6	277.2	239.1
North_Central_Slopes	266.6	242.1	271.8	240.5
Northeast_Coast	253.7	229.4	273.4	221.7
Northeastern_Interior	254.3	231.5	263.6	222.2
Northwest_Coast	288.3	259.3	284.6	256.4
Northwest_Slopes	291.3	263.0	280.7	247.3
South_Central_Coast	255.8	232.4	278.4	229.2
South_Central_Slopes	254.9	242.2	265.7	226.9
Southeast_Coast	258.2	232.4	278.5	219.6
Southwest_Coast	260.5	228.3	282.9	231.4
Southwest_Slopes	266.2	242.1	277.9	236.0
Vieques	258.1	227.5	281.5	217.4
Western_Interior	275.7	262.8	270.8	242.3

A common measure of temperature stress is the count of days above 90°F. In Figure 395, we present a revision of this: the y-axis of the graphs shows the difference of projection to baseline of the count of days where the maximum temperature is above a moving threshold that forms the x-axis of the graphs. The counts are averaged across years, per the regions described above.

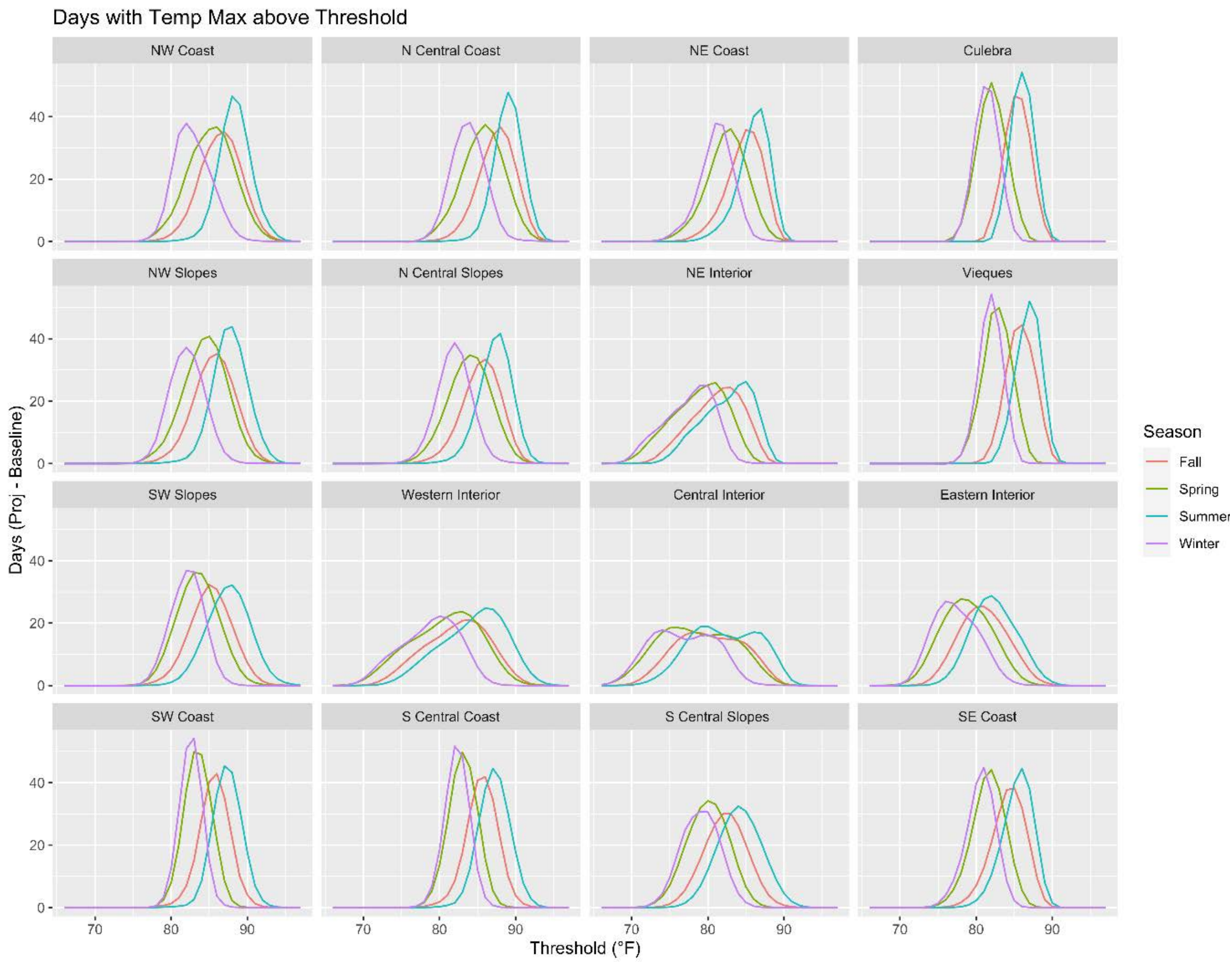


Figure 394. Difference in the average number of days, baseline to projection, on which maximum temperature exceeds a threshold (°F), per region and season

The pattern of increase in minimum daily temperature is also evident in Figure 396, which illustrates the days when the minimum temperature exceeded the threshold, an indication of whether the nighttime offered relief from the heat.

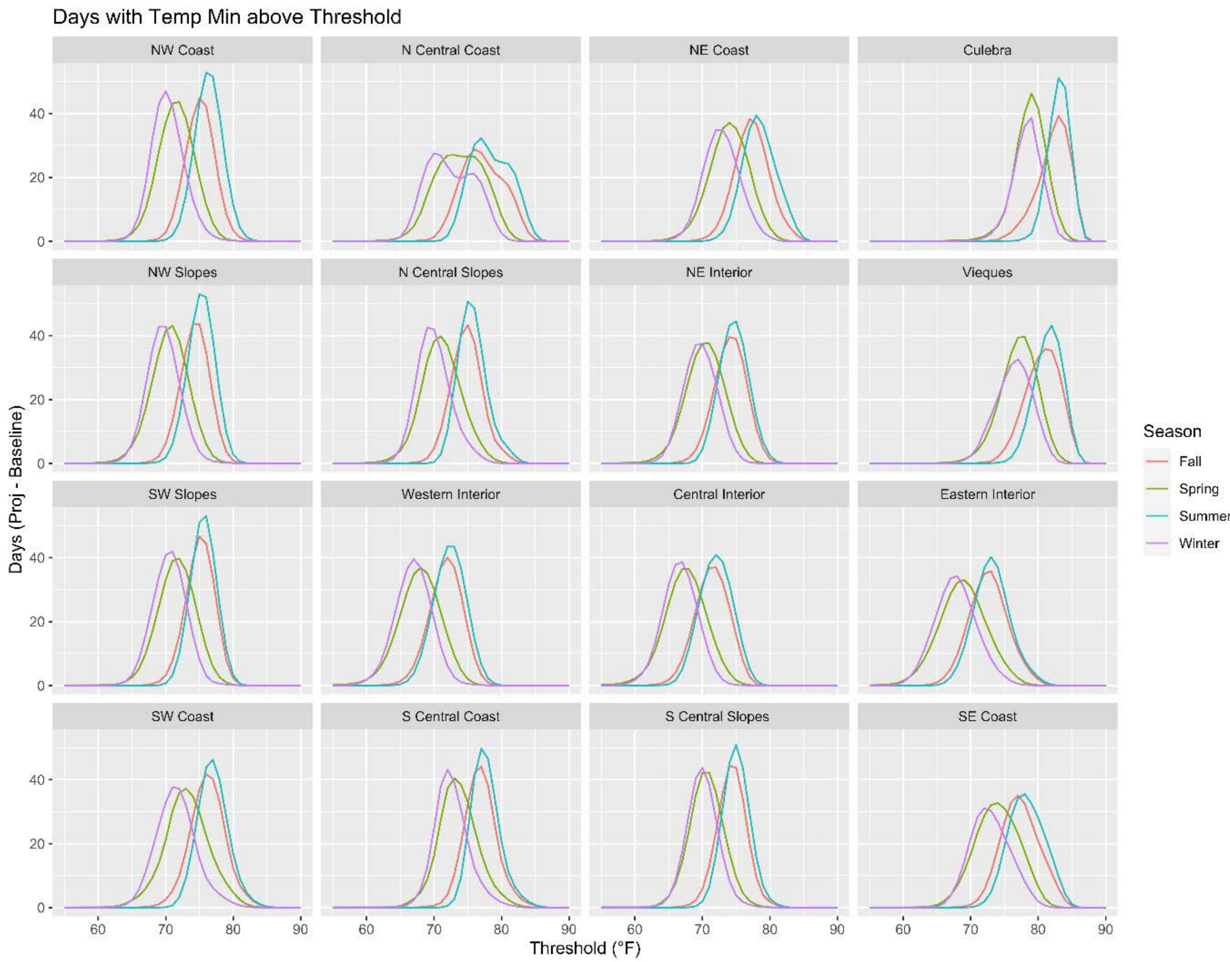


Figure 395. Difference in the average number of days, baseline to projection, on which minimum temperature exceeds a threshold (°F), per region and season

13.4.2 Precipitation

As noted above, simulation of precipitation is challenging. Previous reports (USGCRP 2018) have suggested long-term drying in tropical areas in general and the Caribbean specifically. The ADDA simulations suggest a more detailed and varied pattern. Table 66 reflects this. Winter sees increases in all regions, at substantially higher values than other seasons. Spring, conversely, sees general decreases in most regions. Summer exhibits slight increases in almost all regions, and fall sees more substantial increases in most regions, with a few showing decreases.

Table 66. Precipitation Difference by Region and Season, in Average (mm/day)

Region	Spring	Summer	Fall	Winter
Central_Interior	-1.3	-0.2	-0.2	1.1
Culebra	-0.3	0.8	1.7	1.5
Eastern_Interior	0.1	0.4	0.6	1.4
North_Central_Coast	-0.2	0.8	1.6	1.0
North_Central_Slopes	-0.3	0.2	1.1	1.2
Northeast_Coast	0.8	1.4	1.5	2.2
Northeastern_Interior	0.5	1.2	0.6	2.4
Northwest_Coast	-1.2	0.6	0.3	0.8
Northwest_Slopes	-1.9	-0.5	-0.4	0.4
South_Central_Coast	-0.5	1.0	-0.5	1.1
South_Central_Slopes	-0.8	0.3	0.0	1.4
Southeast_Coast	0.2	0.4	-0.7	1.1
Southwest_Coast	-0.9	0.8	-1.3	1.3
Southwest_Slopes	-1.3	0.0	-1.6	1.0
Vieques	-0.4	0.3	-0.3	1.2
Western_Interior	-1.8	-0.7	-1.2	0.6

A second analysis examined the changes in extremes of precipitation: the prevalence of dry days at one extreme, and the occurrence of very heavy precipitation at the other.

The methodology for this analysis was to inventory the daily precipitation totals (total mm/day) for all days in the baseline period, remove days with zero precipitation, and divide these into percentile-based bins reflecting the lowest 5%, 5%–10%, et cetera. The values for daily precipitations in baseline period at the boundaries of these bins are then used to classify the days in the equivalent inventory for the projection period. This is then used to calculate a percentage out of the total for the projection period. (For example, if 5% of the days in the baseline period had daily rainfall totals between 0 mm and 5 mm, and in the projection period 15 days fell within that range out of 200 days, then the projection period percentage is 7.5%, which is an increase of 50% from the baseline period's 5%.).

Figure 397 gives the results for winter, the season indicating the greatest increases in precipitation. The general pattern is one of decreases in middle-range values, slight increases in very low values and days with zero precipitation (leftmost bin), and significant increases in the highest percentiles.

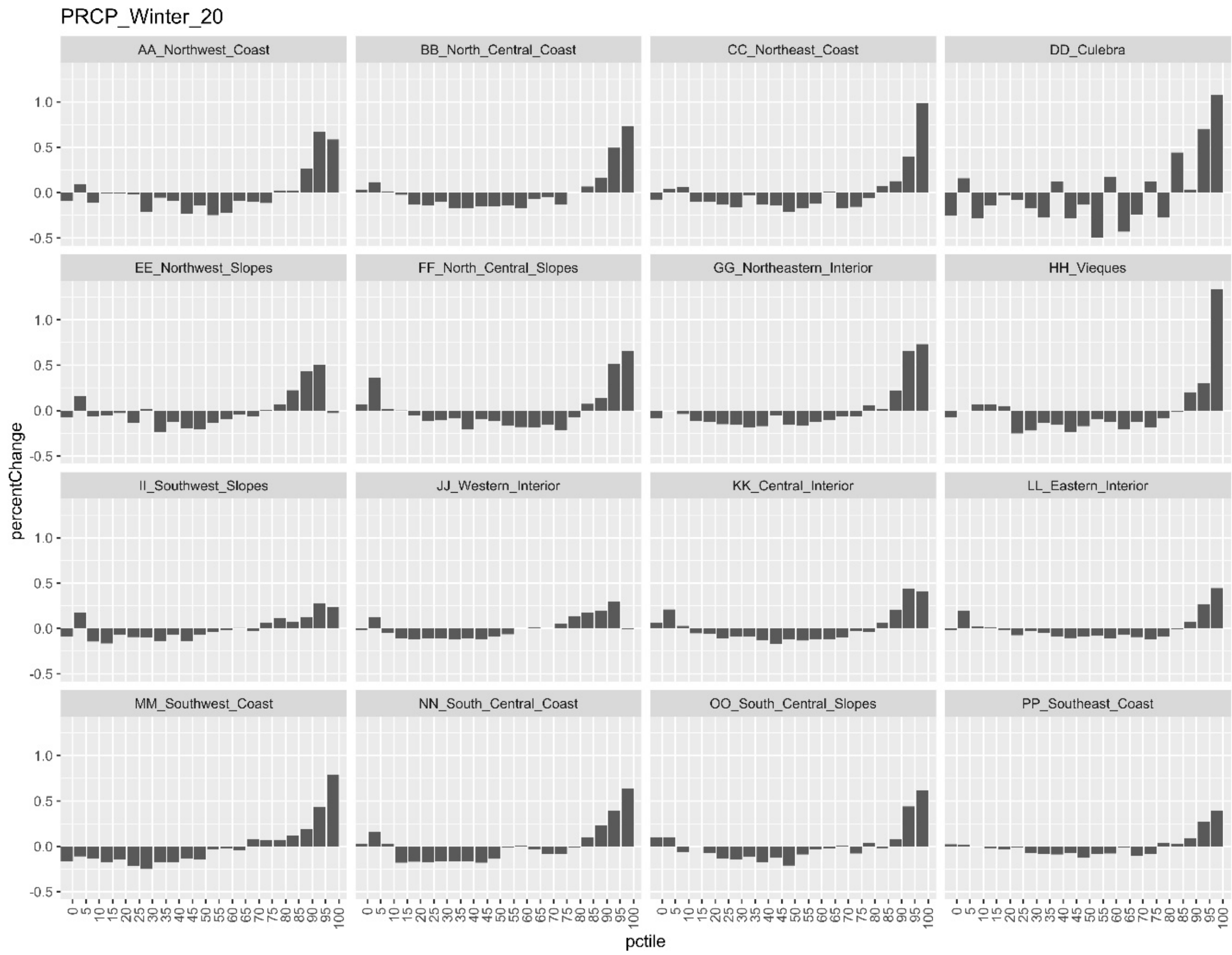


Figure 396. Increases (by percentage) in projection period, winter, of numbers of days with rainfall in baseline-defined percentiles (5% intervals; days with no rainfall in leftmost bin)

Spring (Figure 398) provides examples of a pattern in which the extreme lows and highs grow at the clear expense of the middle ranges (e.g., Southeast Coast, Eastern Interior, Northeast Coast, and Central Slopes). Other regions show different patterns (e.g., Southwest Coast, which shows a simple decline).

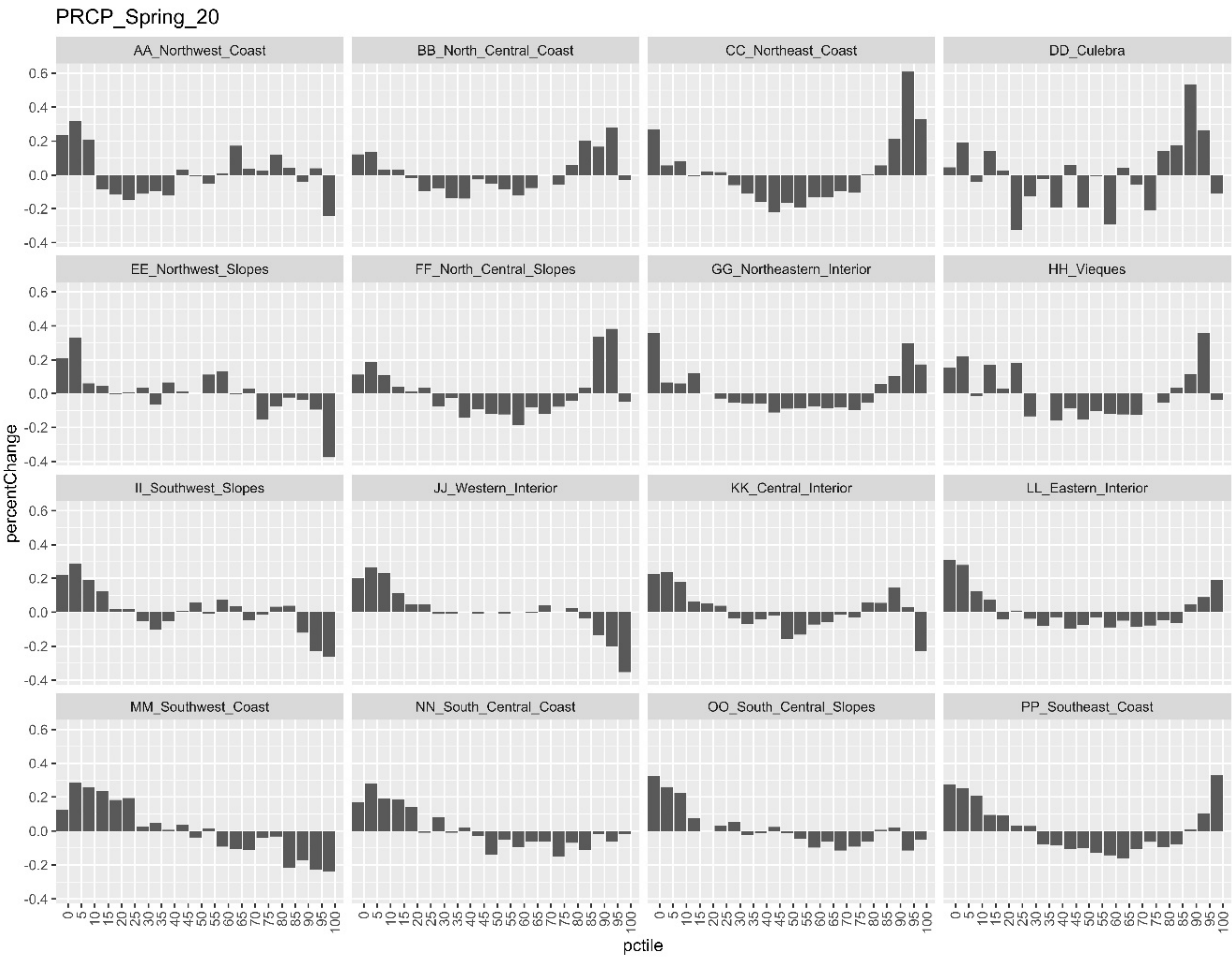


Figure 397. Increases (by percentage) in projection period, spring, of numbers of days with rainfall in baseline-defined percentiles (5% intervals; days with no rainfall in leftmost bin)

These patterns vary further in the other seasons, so that some regions experience clear declines (e.g., Western Interior, summer, Figure 399) and others show the movement to the extremes (e.g., North Central Coast, fall, Figure 400).

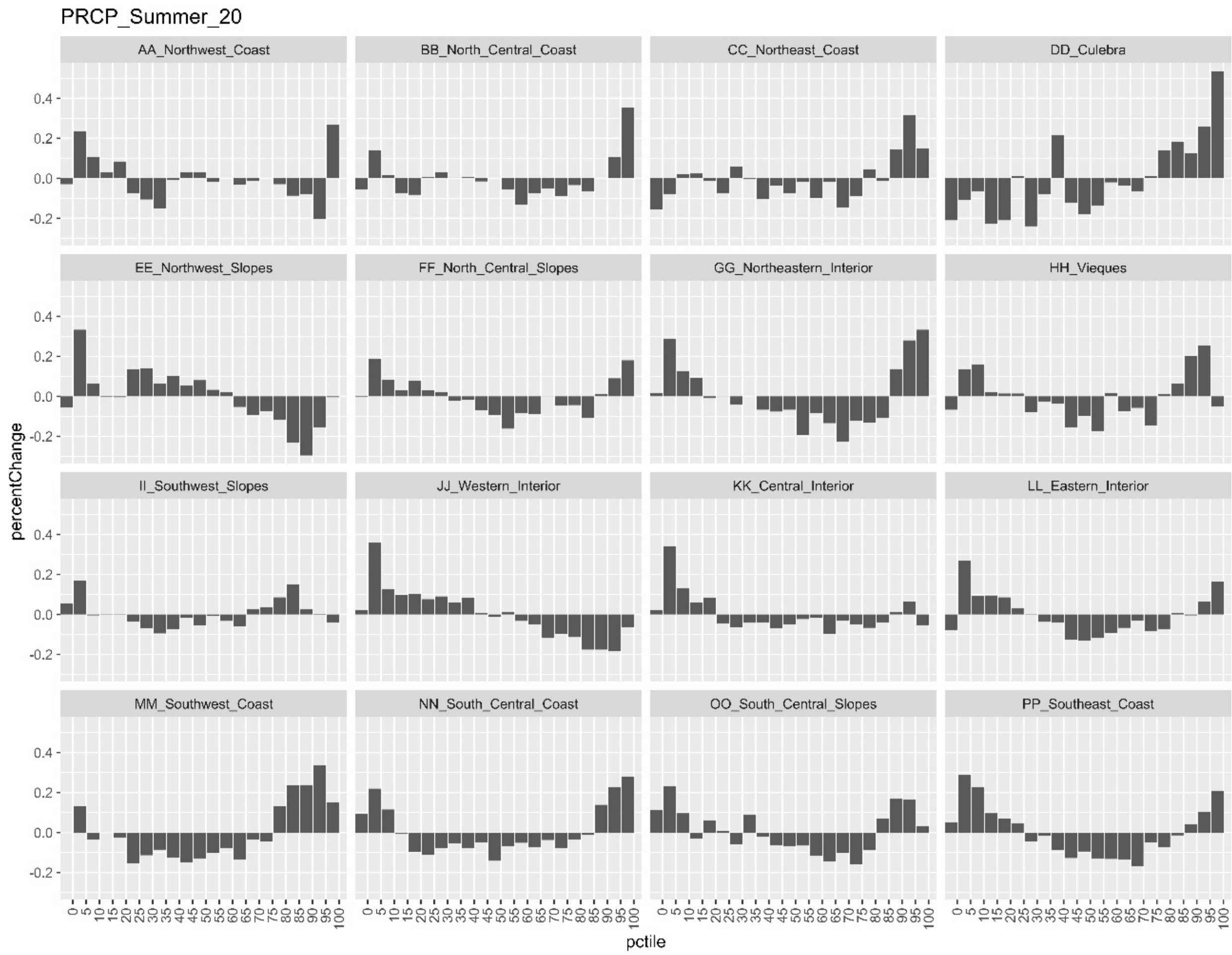


Figure 398. Increases (by percentage) in projection period, winter, of numbers of days with rainfall in baseline-defined percentiles (5% intervals; days with no rainfall in leftmost bin)

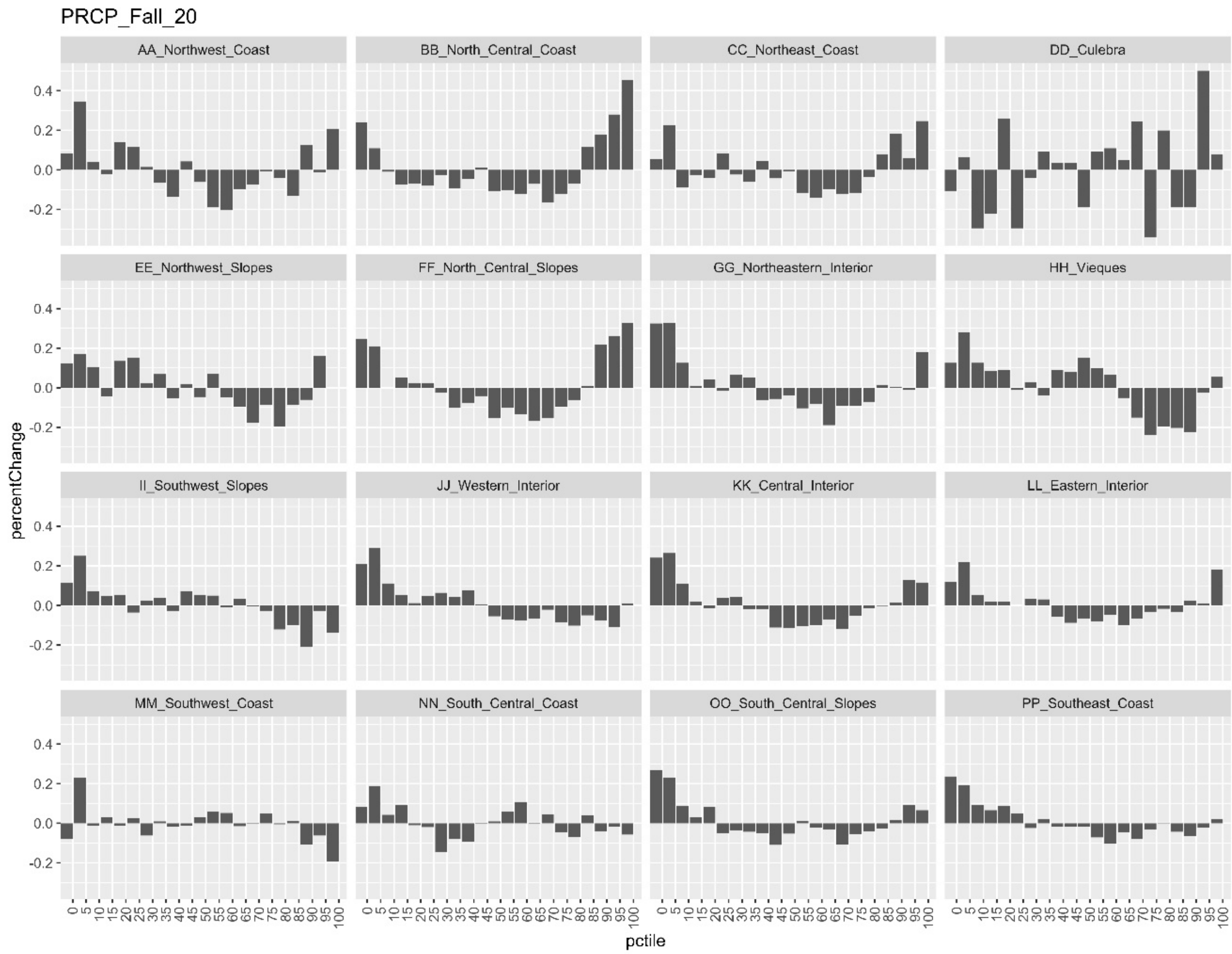


Figure 399. Increases (by percentage) in projection period, winter, of numbers of days with rainfall in baseline-defined percentiles (5% intervals; days with no rainfall in leftmost bin)

For the preceding analysis, all days in the projection period that exceeded the maximum value in the baseline period are placed in the top bin. However, to understand the number of days like this, and the magnitude of the rainfall on those days, Figure 401 and Figure 402 show the maximum baseline values (red squares) and all of the projection values that exceed that baseline (blue circles), per period, per region. Note that in some seasons and regions, no values exceeded baseline's maximum. However, for others (e.g., North Central Coast, fall) the number of values exceeding the maximum is large, and their relative magnitude is also extremely high, reaching almost a 180% increase.

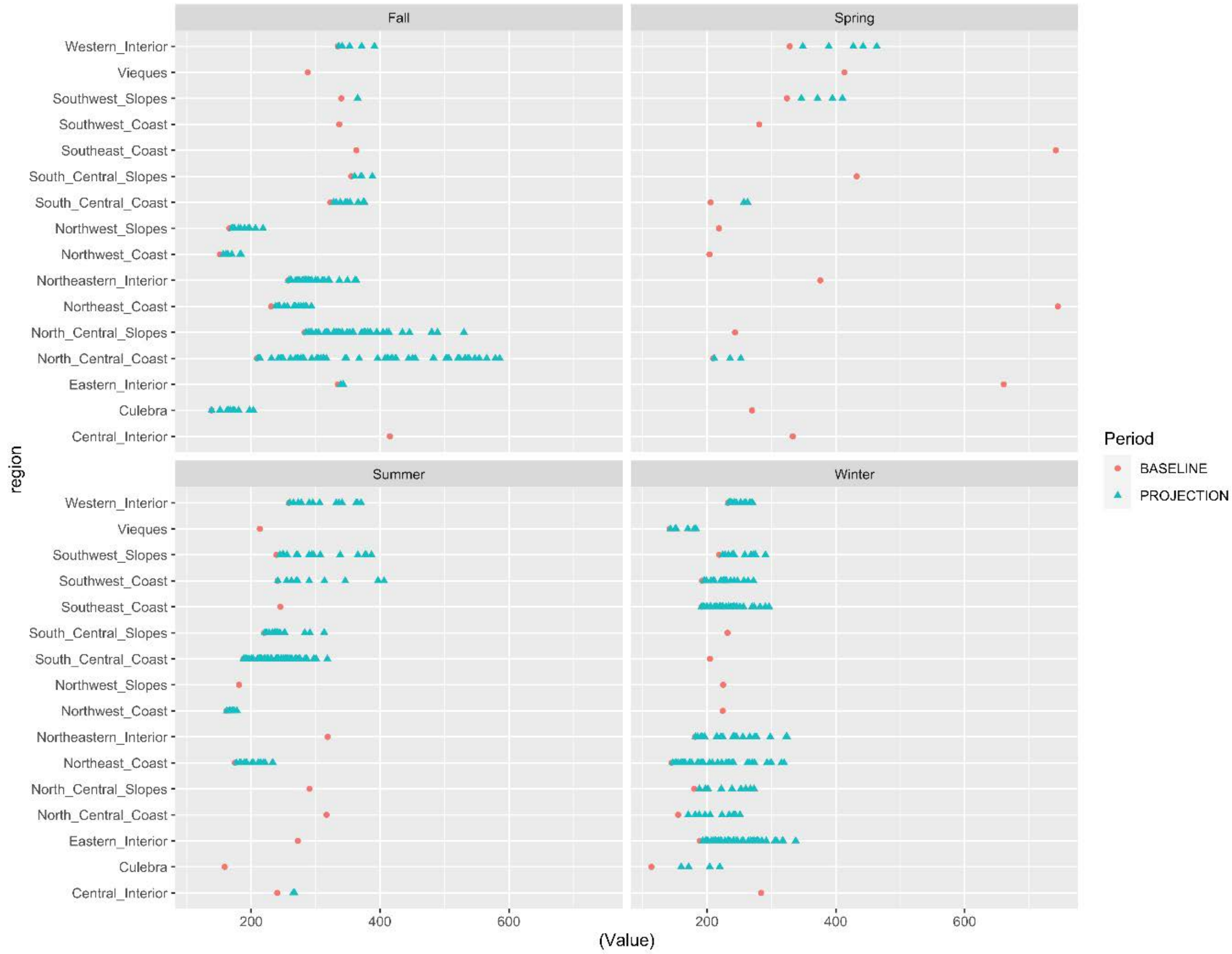


Figure 400. Absolute values for days with total precipitation exceeding maximum daily precipitation in baseline (red), per region and per season (mm)

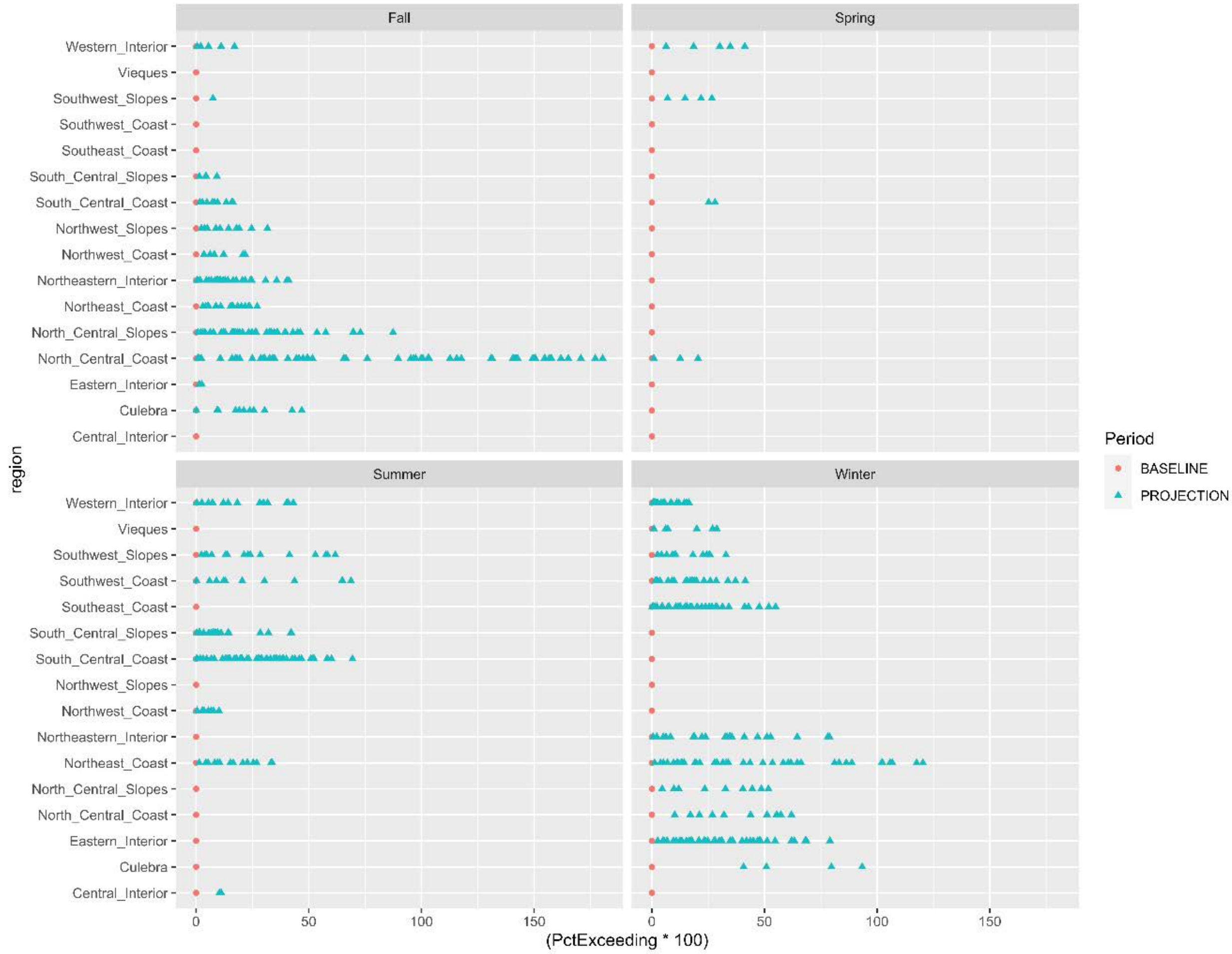


Figure 401. For all days in projection period for which daily precipitation exceeds maximum seen in baseline, percentage by which total precipitation exceeds maximum daily precipitation in baseline (red), per region and per season

13.4.3 Solar Radiation and Wind

Figure 403 presents the reduction in solar radiation observed in the projection versus baseline period, using an analysis similar to the temperature analyses discussed above. The unit analyzed was the total watts per each simulated day. These were then assessed against a threshold value (x-axis), and a count of days per each season that failed to meet that threshold was created. These counts were then averaged across years within the baseline and simulation period (fall 1999 and winter 2046 removed; see Appendix L). The y-axis shows the difference between the number of days below the threshold in the projection period versus the number of days in the baseline period. For very low and very high thresholds, there is no difference: all days either exceed the low threshold or fail to meet the high threshold. However, between these extremes can be observed a curve that reflects the greater frequency of days on which solar radiation will fail to meet a particular threshold.

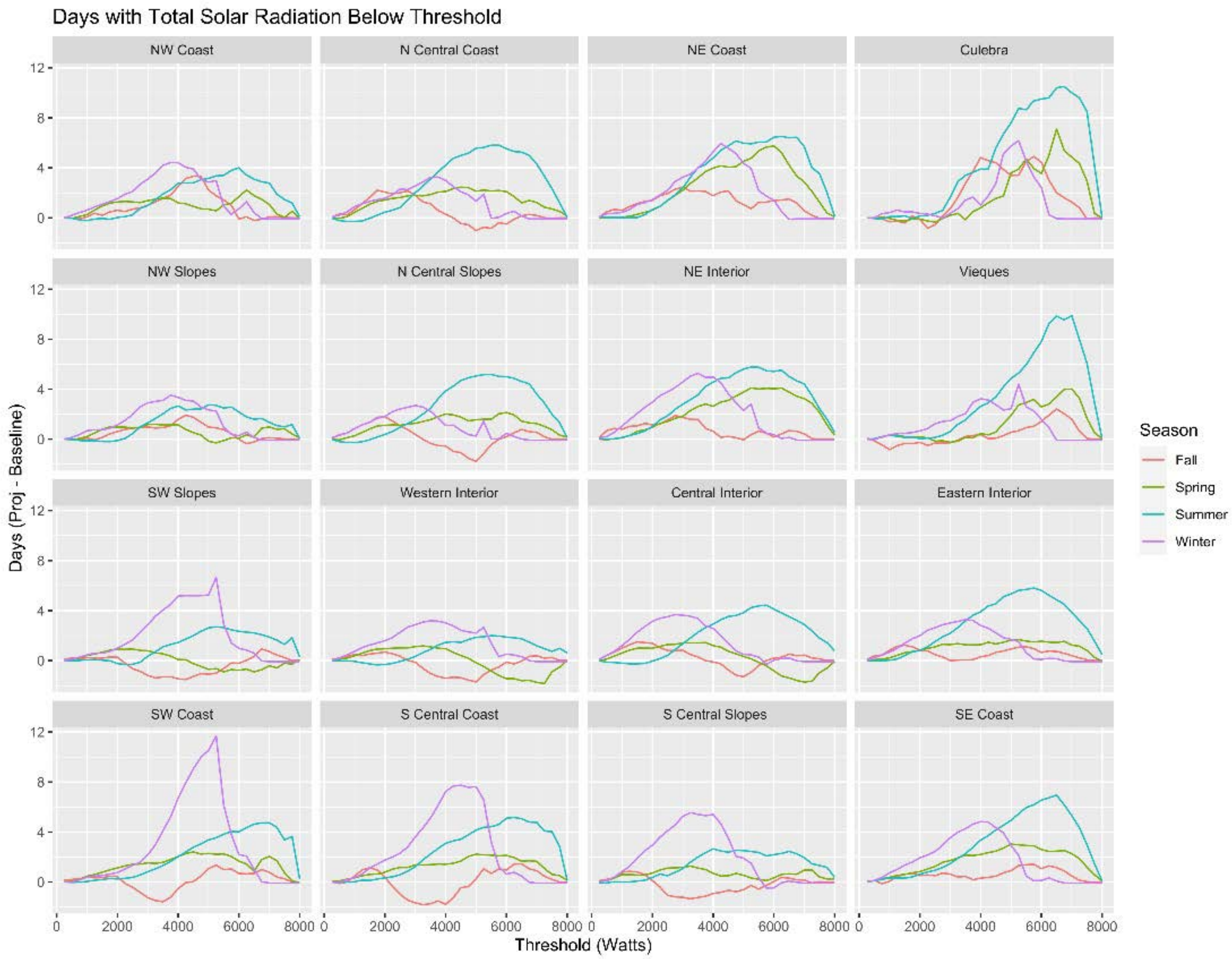


Figure 402. Difference in number of days from baseline to projection, by region and season, in which total solar radiation fails to meet a given threshold (watts, x-axis)

There are some regions and seasons that see more days in the baseline period that are below the threshold than in the projection period; these are negative numbers on the graph and reflect an increase in solar radiation. However, there are also regions and seasons that see many more days in the projection period that are below the threshold than were in the baseline period; these are decreases in solar radiation. For example, in the Southwest Coast in winter, there are expected to be nearly 12 more days that fail to reach ≈5,250 total watts in the projection period than in the baseline. These curves can be expected to be centered at different thresholds for different seasons, because the total watts available is lower in winter, higher in summer, and between these for fall and spring.

Average wind speeds are simulated to decrease slightly in most regions and seasons. Table 67 gives the percentage decrease, by region and season, of average daily wind speeds.

Table 67. Percentage Change in Average Wind Speed, per Region and Season, Baseline to Projection

Region	Spring	Summer	Fall	winter
Central_Interior	0%	-3%	1%	-3%
Culebra	-2%	-6%	-2%	-2%
Eastern_Interior	-2%	-5%	0%	-3%
North_Central_Coast	-2%	-4%	0%	-3%
North_Central_Slopes	-2%	-4%	1%	-2%
Northeast_Coast	-4%	-5%	-1%	-4%
Northeastern_Interior	-3%	-5%	0%	-4%
Northwest_Coast	-1%	-3%	-1%	-3%
Northwest_Slopes	-1%	-2%	0%	-3%
South_Central_Coast	-2%	-3%	1%	-5%
South_Central_Slopes	-1%	-2%	2%	-4%
Southeast_Coast	-3%	-4%	0%	-4%
Southwest_Coast	-2%	-3%	1%	-5%
Southwest_Slopes	0%	-2%	2%	-4%
Vieques	-2%	-5%	1%	-2%
Western_Interior	0%	-1%	2%	-3%

Maximum wind speeds generally show increases in the projection period above the baseline, especially in spring and fall, with a few exceptions (e.g., Southwest Coast in winter). To further explore this, an analysis similar to the analysis of precipitation extremes was conducted for wind speed. In this case, the maximum daily wind speed was inventoried for all days in the baseline period, then ordered and classed into percentiles, from which boundary values were taken. The same inventory was then created for the projection period, and days were assigned to the percentile period based on the absolute maximum wind speed, with days where the wind speed in the projection period exceeded the maximum for the entire baseline period assigned to the top percentile. (For this analysis, fall 1999 and winter 2046 were removed; see Appendix L for details).

Figure 404 through Figure 407 show the analyses for spring, summer, winter, and fall, respectively. In general, the maximum daily wind speeds increase slightly in most regions and periods. The exception is winter, when maximum daily wind speeds tend to decrease.

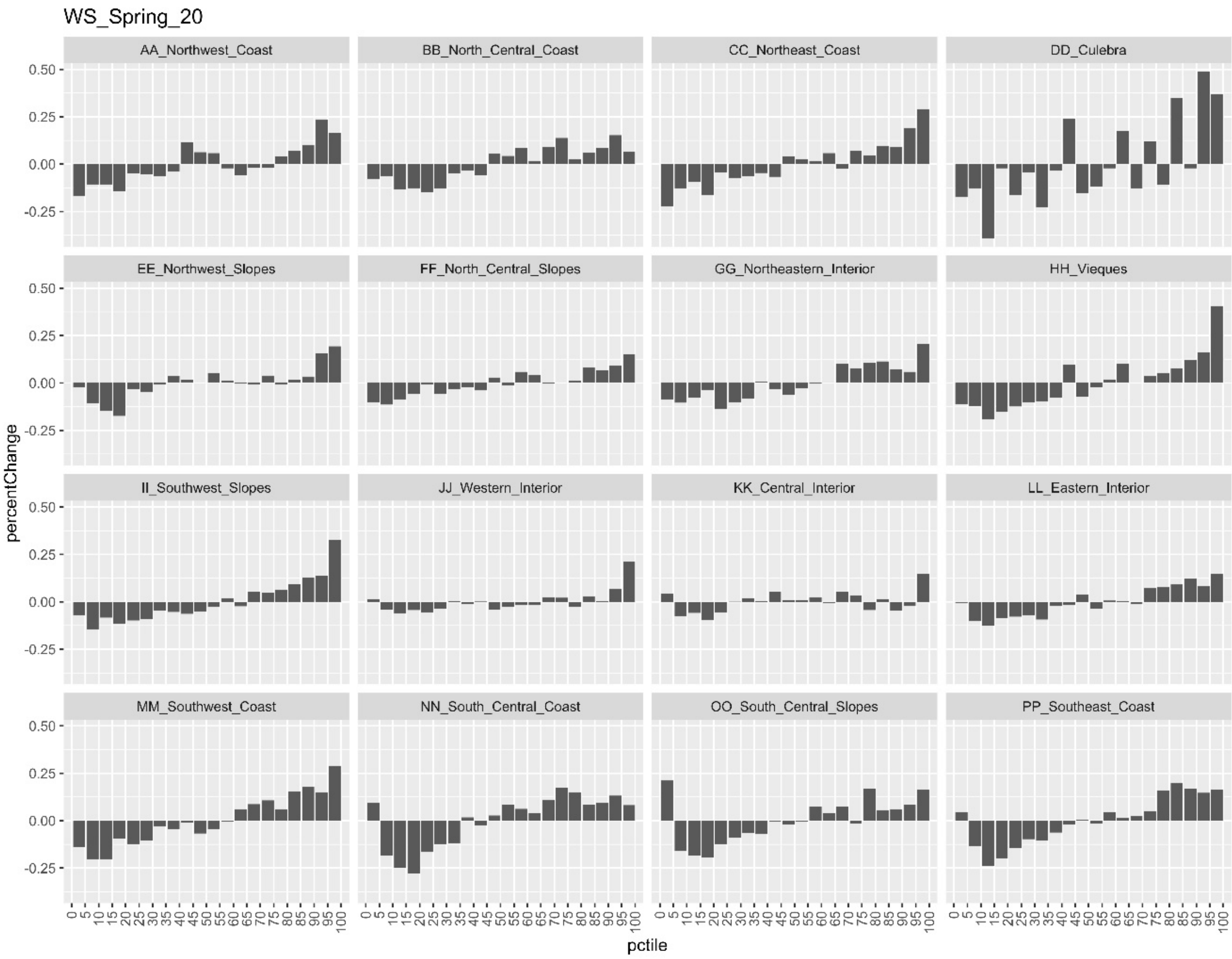


Figure 403. Increases (by percentage) in projection period, spring, of numbers of days with maximum wind speeds in baseline-defined percentiles (5% intervals; days with no rainfall in leftmost bin)

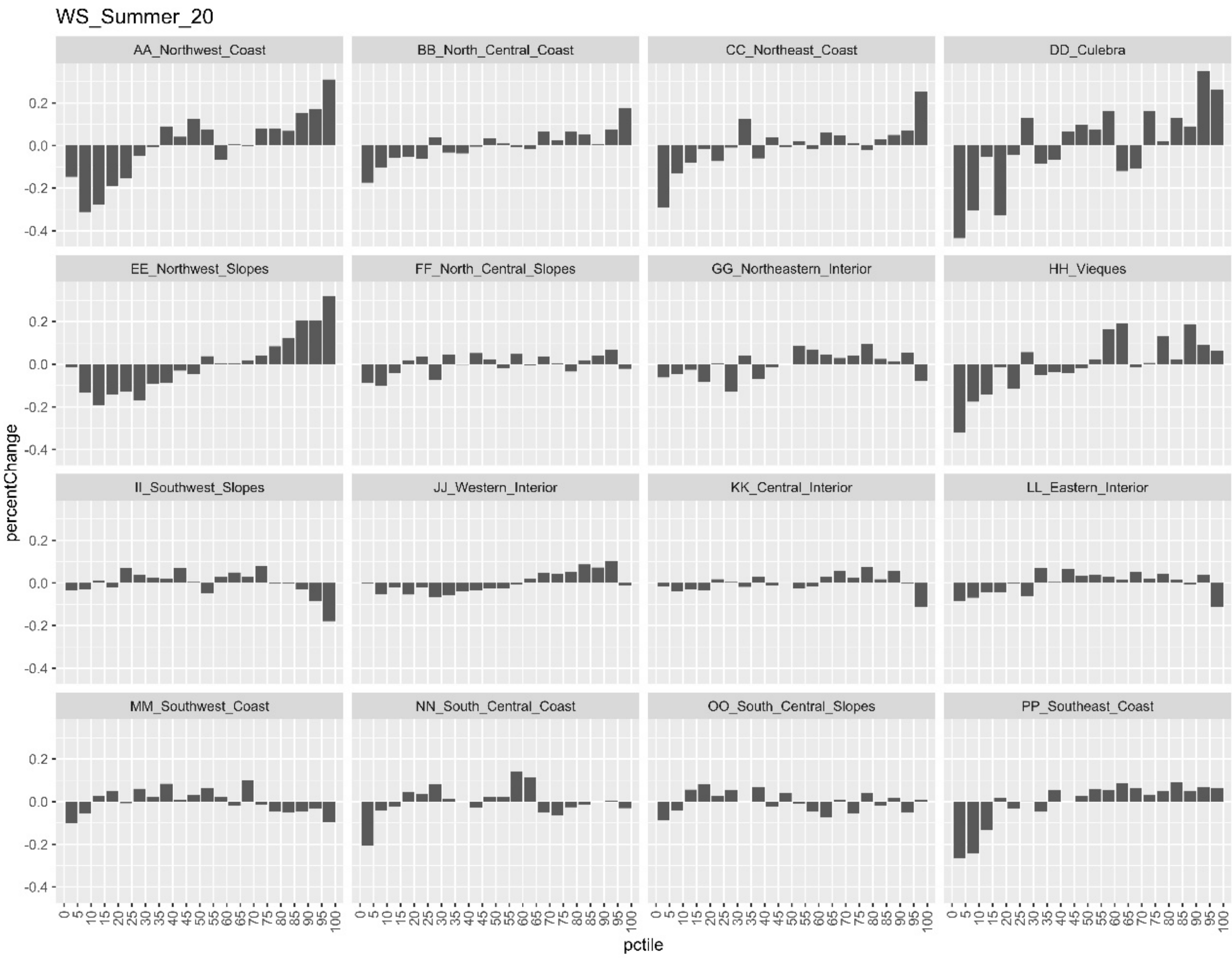


Figure 404. Increases (by percentage) in projection period, summer, of numbers of days with maximum wind speeds in baseline-defined percentiles (5% intervals; days with no rainfall in leftmost bin)

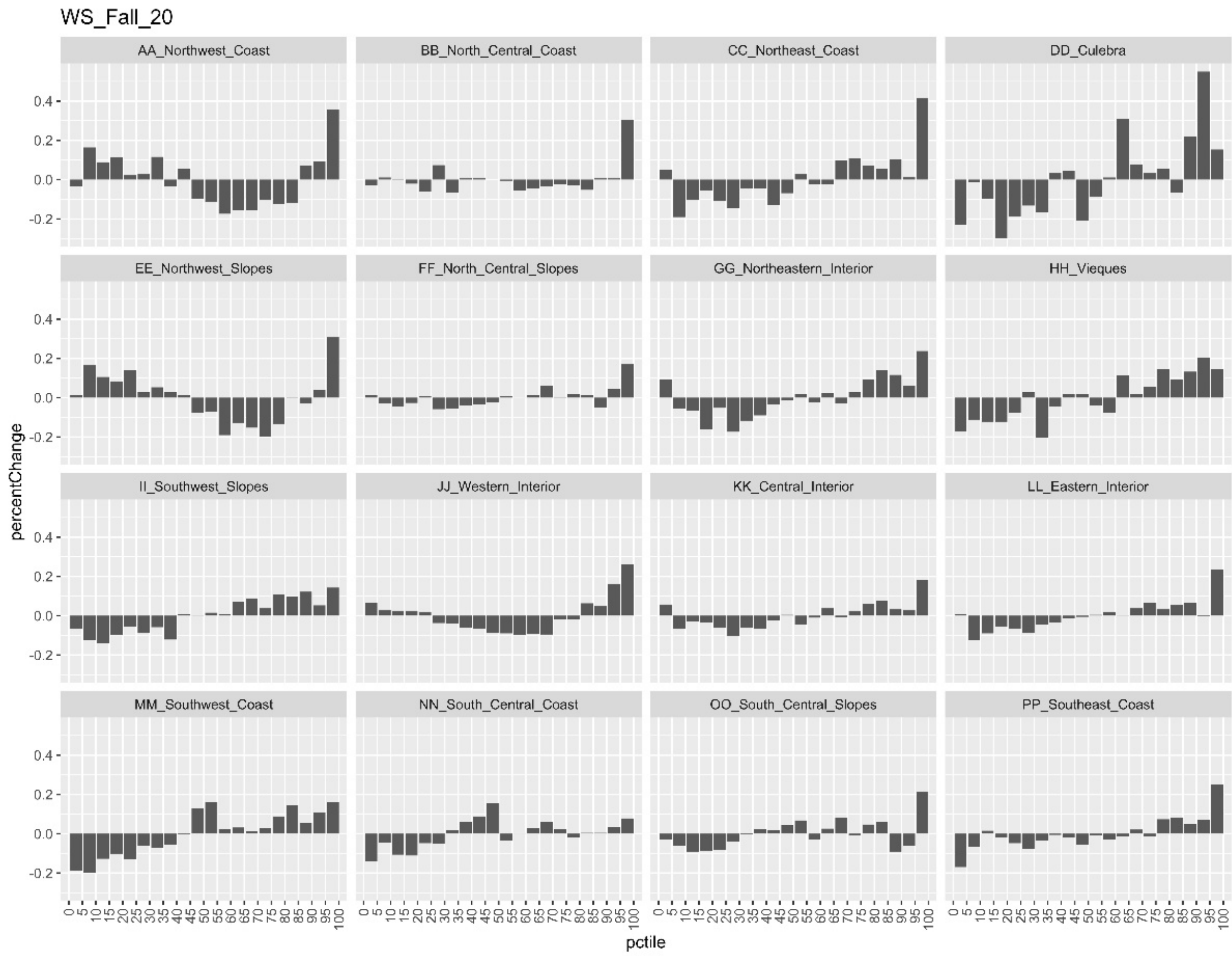


Figure 405. Increases (by percentage) in projection period, fall, of numbers of days with maximum wind speeds in baseline-defined percentiles (5% intervals; days with no rainfall in leftmost bin)

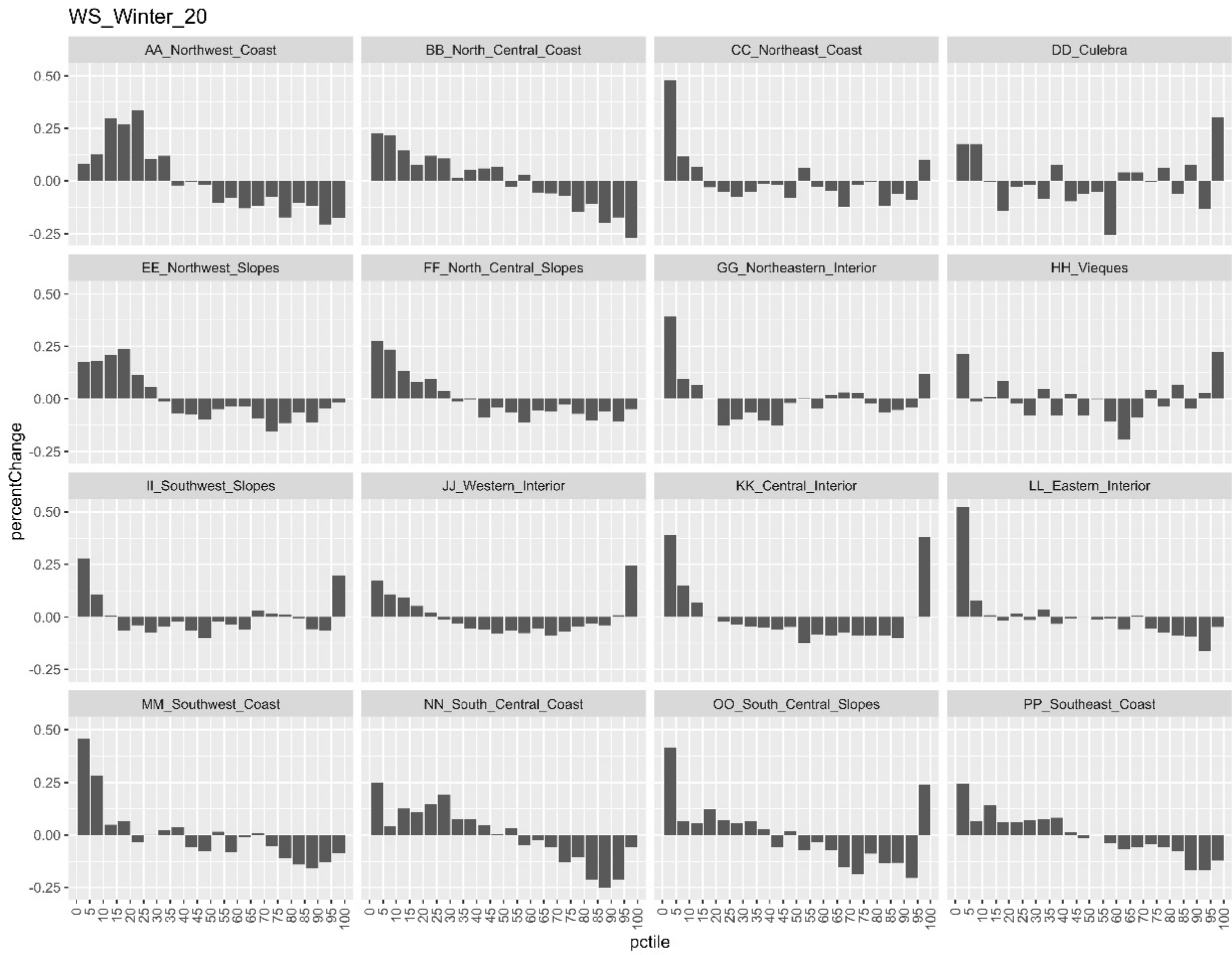


Figure 406. Increases (by percentage) in projection period, spring, of numbers of days with maximum wind speeds in baseline-defined percentiles (5% intervals; days with no rainfall in leftmost bin)

This general picture of increase, however, is different from consideration of the most extreme winds—that is, the highest category and those instances that exceed the maximum seen in the baseline period. Figure 408 presents the days in which the wind speed in the projection period exceeded the highest in the baseline period, using the absolute value of the maximum wind speed; Figure 409 presents this as a percentage increase above the maximum. In neither spring nor summer did the maximum in the projection period exceed the maximum seen in the baseline. The maximum in the baseline was exceeded for only a few regions in the fall but was exceeded in most regions in the winter. The implication is that winds across Puerto Rico, in spring, summer, and fall, see higher maximum wind speeds in general but rarely exceed the maximum from the baseline period. Winter, conversely, sees a general decrease but higher extremes, although this increase is never more than 40%.

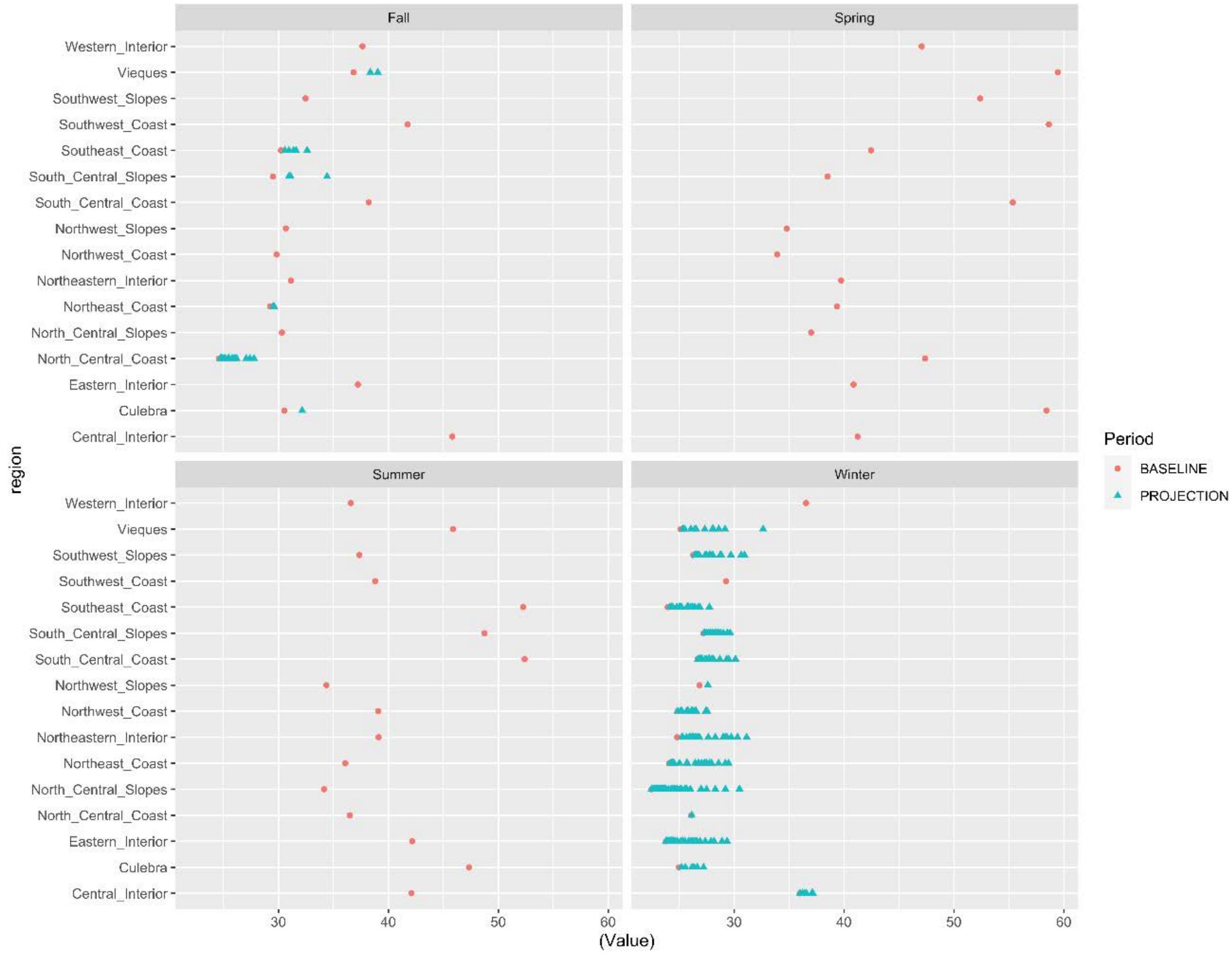


Figure 407. Absolute values for days with maximum wind speed exceeding maximum daily precipitation in baseline (red), per region and per season

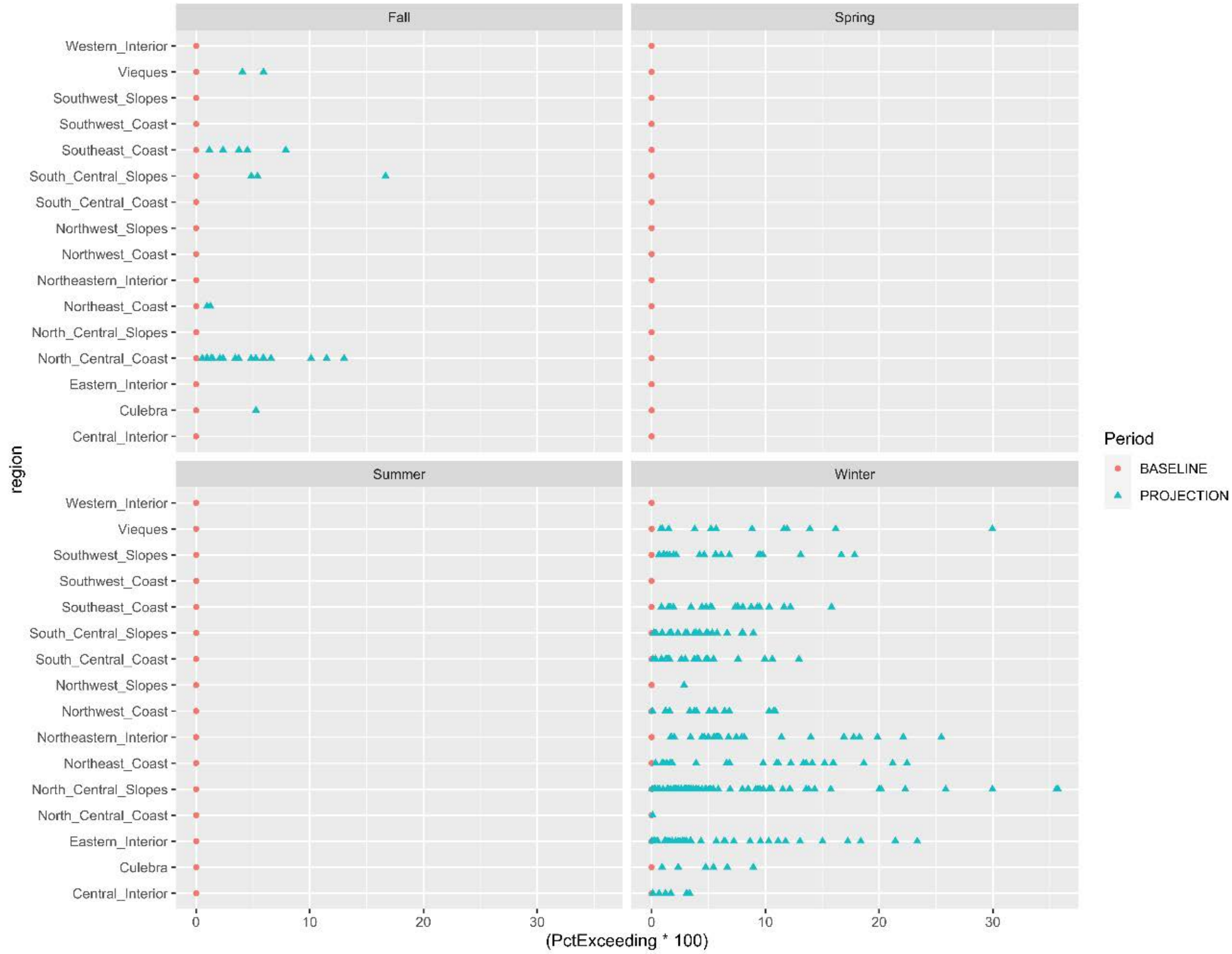


Figure 408. For all days in projection period for which daily maximum wind speed exceeds maximum seen in baseline, value by which daily maximum exceeds maximum daily precipitation in baseline (red), per region and per season

13.4.4 Summary: Regional Analyses

Although spatial and temporal variation is not uniform, some generalizations across the climate variables can be made:

- For the Northwest Coast, Northwest Slopes, and Western Interior regions, temperature increases in spring average 3.2°F, 3.2°F, and 3.1°F respectively; most other regions have values around 2.8°F. These are driven by strong increases in the overnight minimum temperatures, and accompanied by some of the largest springtime decreases in precipitation (-26%, -30%, and -32%). Spring (March-April-May) in these areas will be warmer and drier, more so than other regions.
- The Northwest Slopes, Western Interior, Southwest Slopes, and Central Interior show much smaller increases or even decreases in summer precipitation than the other regions. For the Northwest Slopes and the Western Interior, decreases in precipitation are accompanied by comparatively high increases in mean, minimum, and maximum temperatures, meaning summers will be warmer and drier in these regions.

- The North Central Coast and North Central Slopes see comparatively high increases in fall precipitation; most other regions show only small increases or decreases.
- Winter precipitation increases across the archipelago, with very high values in the Southwest Coast and Northeast Coast regions.
- Vieques and Culebra will differ from the main island. Precipitation increases in summer and fall will be large, and increases in winter will be among the largest values across the data set (60% for Vieques, 74% for Culebra).

13.5 Interpretation

We note the following considerations:

1. Future work should contribute additional models and other scenarios that can be added to these results.
2. Future work can be done to analyze the frequency and magnitude of extreme events.
3. Downscale climate model outputs can and should be used for a wide array of infrastructure planning (e.g., housing, water management, communication systems, transportation, and energy).
4. Investments should incorporate those solutions that are most efficient and pragmatic to meeting the desired lifespan of the infrastructure in light of climate-driven risks.

Consideration: Future work should contribute additional models and other scenarios that can be added to these results.

The ADDA represents a new step forward in large-scale, fine resolution climate modeling. The current limitation of the ADDA v2 used for this study is that it represents only one variation out of a set of possible alternate models. These include:

- Models that use different general circulation models as their base data
- Models that consider different SSPs.

These models can—and indeed are expected to—disagree in magnitude of changes and even in sign of changes such as for precipitation; the variation in results, however, can be informative, and in some cases the averages of different models are considered a better representation of likely reality than any individual model. In other cases, some biases of one model can be balanced by biases in another.

Consideration: Future work can be done to analyze the frequency and magnitude of extreme events.

The ADDA data set enables calculations of a variety of extreme events; these can include extended periods of heat, droughts, extended periods of low solar radiation, and tropical storms or hurricanes with intense precipitation and wind. However, the analyses to reveal and study these were not performed as part of PR100. One reason is that these could be better performed across wider regions (e.g., understanding the development of tropical storms beyond the boundaries of the PR100 data set). However, most analyses of this kind were out of the PR100 scope.

Consideration: Downscale climate model outputs can be used for a wide array of infrastructure planning (e.g., housing, water management, communication systems, transportation, and energy)

The promise of these downscaled climate simulation results is that detailed planning can be performed using their future projections on tight spatial scales. Global-scale general circulation models provide general trends across wide regions on long time scales; these downscaled simulations translate these into more useful information that can guide siting decisions, performance requirements, engineering specifications, asset lifespan predictions, and other aspects of infrastructure planning. The simulations are not a perfect window into the future, but when performed in ensembles that cross multiple modeling approaches and multiple future climate scenarios, they can be an extremely useful guide to planning a resilient, sustainable, and renewable energy future. Downscaled climate modeling should inform infrastructure investment, design, and management decision-making to ensure siting and operational requirements are informed by climate projections.

Consideration: Although climate-cognizant infrastructure may require higher upfront costs, investments should incorporate those solutions that are most efficient and pragmatic to meeting the desired lifespan of the infrastructure in light of climate-driven risks.

Incorporating the design and construction components that will be necessary for the adaptation of new infrastructure to future climate conditions presents significant challenges for infrastructure planners due to their additional costs. These components are likely to increase the overall investment requirements for the assets themselves as well as for investments that must be made in the areas immediately surrounding the new assets (e.g., expanded drainage or elevated foundations to protect the asset from rising precipitation). The corresponding costs to ensure that a new infrastructure asset will be capable of operating for its intended lifespan may prove to be difficult to quantify at the proposal stage and difficult to justify in light of finite budgets for these improvements. However, these higher up upfront costs must be understood as the “new normal” for ensuring infrastructure designed and constructed in climate-vulnerable areas is equipped to operate in its evolving risk landscapes (Simpkins 2021).

14 Infrastructure Interdependency and Social Burden Evaluation

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Section Summary

This section presents methodologies and results of two assessments conducted as part of PR100 with a particular bearing on energy justice: infrastructure interdependency among energy, water, communications, and transportation systems; and social burden, a quantitative metric to evaluate the effort required at the community level to meet basic societal needs.

We undertook the infrastructure interdependency assessment in PR100 to document the extent to which Puerto Rico's energy infrastructure held interdependent relationships with its communications, water, and transportation infrastructures. Section 14.1.3 provides the results, examining communications (Section 14.1.2.1), transportation (Section 14.1.2.2), and water (Section 14.1.2.3) in turn. Key interpretations of these analyses are given in Section 14.1.3. The methods used to perform these analyses are detailed in Section 14.1.0. Energy justice implications are given in Section 14.1.4.

We conducted the social burden evaluation in PR100 to understand residents' access to key critical services across Puerto Rico during both normal grid operations and during threat scenarios where key community infrastructure assets were assumed to be unavailable. Fifteen critical service types provided by 45 infrastructure asset types were considered for eight different scenarios. The results of the baseline social burden evaluation are given in Section 14.2.2.1, and the results of the threat scenario evaluations are given in Section 14.2.2.2. The energy justice implications of the social burden evaluation are outlined in Section 14.2.3.

This section presents only statistical characterizations of the system as a whole; it does not provide specific examples of infrastructure elements in PR100 due to the sensitive nature of the information and the potential for misuse.

Key Findings

Infrastructure Interdependency Assessment

- Communications, transportation, and water infrastructures are highly interdependent and are highly dependent on energy.
- For communications and water, virtually all distribution-level assets have only one connection: these are vulnerable to a single point of failure. Core elements (e.g., data centers and core components of transportation) have redundant connections.
- Communications infrastructure will expand, change, and be affected by changes in the energy system (e.g., distributed generation).
- Climate-driven stress will impact all infrastructure, but especially water infrastructure.

Social Burden Evaluation

- Baseline social burden results show residents' effort and ability to acquire critical services during "blue-sky" when the electric grid is operating normally. Not every census block or community has the same baseline availability of critical services due to a combination of infrastructure asset availability and economic means.

- In the baseline social burden evaluation, about 98% of individuals fall into the two-lowest categories of social burden. The remaining 2% live in areas with higher baseline social burden, and have more difficulty accessing and acquiring critical services, even when the electric grid is fully operational.
- Resilience threats including flooding, landslides, and earthquakes impact the availability of infrastructure assets and critical services primarily in coastal areas, the interior mountainous region, and the southwest portion of Puerto Rico.
- Social burden increases in all threat scenarios because fewer infrastructure assets that provide critical services are available. The combined threat scenarios that look at landslides, earthquakes, and floods concurrently have the highest impact on social burden, with per capita social burden increasing more than 160% in the Risk Averse scenario as compared to baseline social burden.

Considerations

- Infrastructure Interdependency Assessment
- Improve redundancies in service connections and supply nodes to eliminate single points of failure, especially for elements designated critical supply nodes
- To remain aware of the hazards and risks posed by interdependencies, perform additional and continual assessments of these systems and their interconnections as they evolve
- Coordinate changes across infrastructure domains using a collaborative, systems-of-systems approach.

Social Burden Evaluation

- Identify census block groups and municipalities with high baseline social burden and prioritize grid investments that keep critical services online in those areas
- Perform follow-on social burden evaluations to understand how social burden changes as the availability of infrastructure assets and services changes for threats not included in this study and/or partial grid outages
- Use social burden evaluations to compare the anticipated benefit of different proposed resilience investments.

14.1 Infrastructure Interdependency Assessment

Interconnections in lifeline infrastructure that facilitate cross-sector operations—including energy, communications, transportation systems, and water infrastructure—represent complex interdependencies. These interdependencies are needed for enabling functions among assets and systems of different infrastructure sectors. However, these also multiply the risks posed to infrastructure operations because of the potential for propagation of cascading failures across interconnected assets and systems that could scale up a crisis (Petit et al. 2018). Interdependencies with the energy sector are among the most critical for all other lifeline infrastructure. This section presents our analysis of interdependencies among critical infrastructure sectors in Puerto Rico.

14.1.0 Methodology

The Puerto Rico Infrastructure Interdependency Assessment (PRIIA) tool set is an Esri ArcGIS network analysis application that was developed by Argonne National Laboratory in support of the Infrastructure Systems Recovery Support Function operating from FEMA's Joint Field Office in 2018 (Lewis and Petit 2019). Argonne partnered with the U.S. Department of Homeland Security Cybersecurity and Infrastructure Security Agency, FEMA, and the U.S. Army Corps of Engineers to examine the dependencies satisfied by critical infrastructure (e.g., energy, communications, transportation systems, and water) for facilities that constitute the "community lifelines" in FEMA's response planning construct. These assessments supported the prioritization of recovery funding for critical infrastructures that had sustained damage because of Hurricane Maria (DHS 2018). In support of PR100, the PRIIA tool set was expanded and used to develop a Commonwealth-wide data set of infrastructure service areas and assess interdependencies between the infrastructure systems to (1) identify critical nodes in the communications, transportation, and water infrastructure that depend on specific service connections to distribution substations, (2) determine where the potential exists for disrupted (Esri n.d.), and (3) support complementary analysis by other national laboratories examining the disparate social burdens associated with electricity outages for communities across Puerto Rico.

14.1.0.1 Service Area Modeling

The first step in the PRIIA tool set process is to conduct Huff modeling to estimate the geographic extent of infrastructure service areas associated with the infrastructure assets of concern (e.g., distribution substations, cellular towers, water treatment plants, and wastewater treatment plants) (Esri n.d.). Modeling the geospatial extent of service areas also establishes connections between assets across infrastructure systems and aids understanding of how outages within service area outages propagate across multiple infrastructure systems (Lewis and Petit 2019).

14.1.0.2 Part 1: Establish Probabilistic Service Areas

Probabilistic modeling estimates the service areas with a color-coded scale to illustrate the probability that the result was a reliable estimate based on the location of the asset, its capacities, and the network of distribution channels that are connected to it (e.g., power lines or pipelines). Figure 410 illustrates the notional process of determining probabilistic estimates of service areas (i.e., red for high and green for low) for a selection of infrastructure assets.

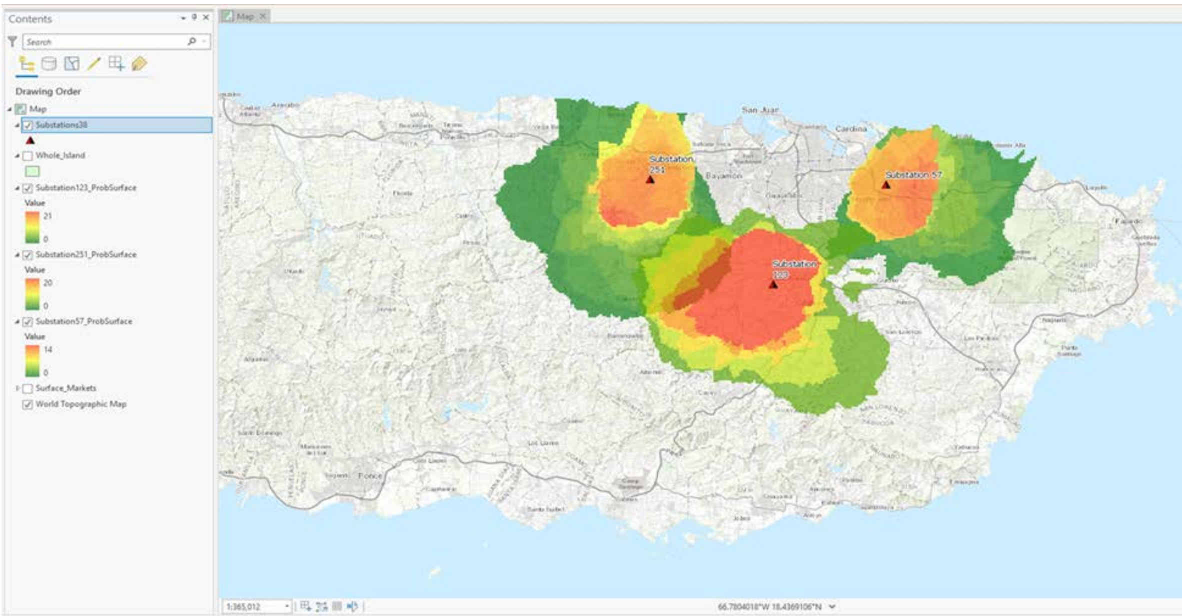

Figure 409. Notional illustration of the probabilistic service area modeling

Illustration by Lawrence Paul Lewis, Argonne National Laboratory

14.1.0.3 Part 2: Derive Deterministic Results

Each iteration of the modeling produced tighter service area polygons with higher probabilities of the corresponding infrastructure service areas. These deterministic results represent the areas that were found to have the highest confidence of being served by a particular infrastructure asset. Figure 411 illustrates the process of refining the modeling of infrastructure asset service areas from probabilistic estimates to deterministic results using Huff modeling.

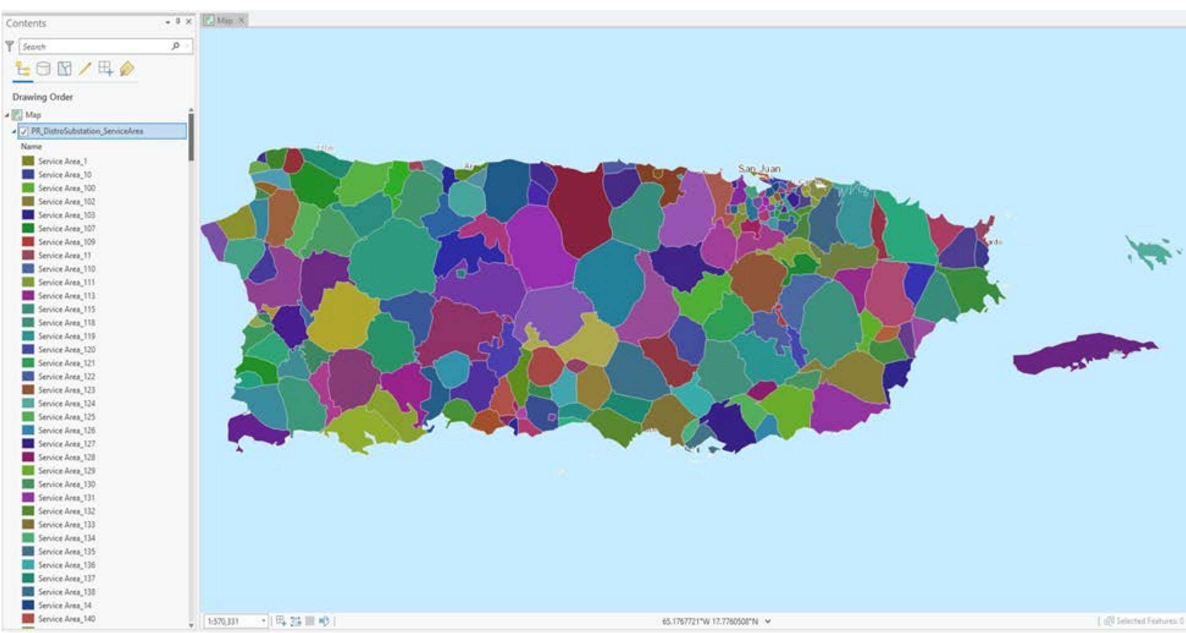

Figure 410. Notional illustration of the deterministic service area modeling

Illustration by Lawrence Paul Lewis, Argonne National Laboratory

14.1.0.4 Cascading Failure Analysis

The second step in the PRIIA tool set process is to leverage these service area modeling outputs to establish interdependent connections among these infrastructure assets in a network simulation. If, for example, a water treatment plant was found to be within the modeled electric power service area of a particular substation, the water treatment plant was associated with that substation as a highly probable point of upstream provision for the electric power on which the water treatment plant depends. That water treatment plant and its modeled water service area were tabulated in this network of interdependent infrastructure as having a first-order dependency on that substation and its service area (i.e., a direct connection throughout a service or resource is provided from an infrastructure asset to a user). Mapping the network of these connections in the PRIIA tool set also illustrates where an infrastructure asset may satisfy a second-order dependency of downstream users (i.e., indirectly support the operations of a downstream user). If, for example, the substation and its service area have an outage that affects the water treatment plant and its water service area as described above, all the customers who depend on water service that has been degraded or disrupted would be recorded in the PRIIA tool set as having their second-order dependency on electric power (and first-order dependency on water service) disrupted (Lewis and Petit 2019).

The resulting cascading failure analysis in the PRIIA tool set provides a visualization of dependencies on and among critical infrastructure assets as well as a tabulation of the potential downstream consequences of first- and second-order dependencies being disrupted for customers—dependencies that also serve the community's important functions (i.e., community lifelines). Figure 412 illustrates a notional propagation of cascading impacts to demonstrate how infrastructure dependencies and interdependencies were assessed in the PRIIA tool set.

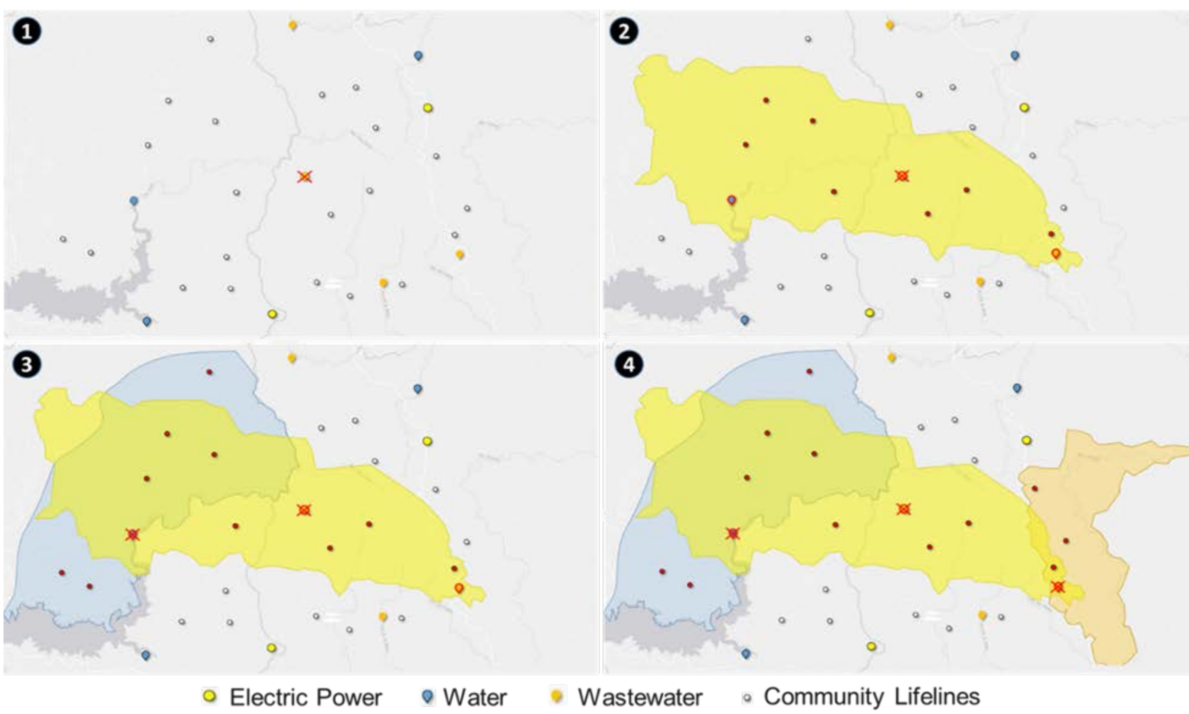

Figure 411. Notional illustration of the propagation of cascading impacts in the PRIIA tool set

Illustration by Lawrence Paul Lewis, Argonne National Laboratory

Figure 412 illustrates the simulation results from the disruption of a single electrical distribution substation as its impacts propagate to water service, wastewater service, and community lifelines that may be affected by interruptions to first- and second-order dependencies on these three infrastructure services, as follows:

1. Quadrant 1 illustrates the initial disruption to an electrical distribution substation, marked with a red “X” over the critical infrastructure asset. Each of the propagation scenarios presented in this report involved the initial disruption of one critical infrastructure asset at a time.
2. Quadrant 2 illustrates the service area of the disrupted electrical distribution substation estimated using the Huff model, represented as a yellow-shaded area. Other infrastructure assets and community lifelines within this impacted service area may be affected by the loss or degradation of electric power provided by this substation. These results may be used to identify which infrastructure asset satisfies the first-order dependencies of community lifelines and other infrastructure assets on a particular resource or service.
3. Quadrants 3 and 4 illustrate other infrastructure assets within the initial disrupted service area (also marked with a red “X”) that may be affected by the disruption of electric power service, with the service area for water represented by the blue-shaded area and that of wastewater represented by orange-shaded areas. These results may be used to assess the potential propagation of cascading impacts from the initial disruption across other dependent infrastructure assets serving the same community.
4. Quadrant 4 illustrates the total number of critical infrastructure assets and community lifelines within the initial and propagated disruptions. These results may be used to identify critical infrastructure assets that satisfy both first- and second-order dependencies of community lifelines for multiple infrastructure services (i.e., the loss of a first-order dependency on water through the second-order dependency on electric power). These results may also be used to identify which community lifelines may be affected by the compounded effects of losing more than one infrastructure resource or service in one scenario (i.e., community lifelines within both the impacted electric power and water service areas).

Numerous iterations of these cascading failure scenarios were conducted on interdependent energy, communications, transportation systems, and water infrastructure assets across the Commonwealth. However, this assessment and its results were not intended to be definitive infrastructure system modeling or vulnerability assessments of all critical infrastructure in Puerto Rico. Additional data on system-level infrastructure operations would be required for a more advanced assessment. Rather, this assessment is intended to serve as a screening tool for interdependent infrastructure relationships. Screening for these interconnections between the infrastructure assets and systems can be used to inform the identification, prioritization, and implementation of renewable energy infrastructure planning and investment that would result in the widest possible enhancements to community resilience and energy justice across the Commonwealth.

14.1.1 Inputs and Assumptions

The PRIIA tool set was originally developed to conduct interdependency assessments in a selection of regional case studies to determine how to prioritize recovery funding for critical infrastructure considering the number and criticality of its dependent downstream functions and customers. Although the PRIIA tool set is now being applied to a distinct question of how an understanding of infrastructure interdependencies can support a just transition to a renewable energy landscape across all of Puerto Rico, the inputs and assumptions of the PRIIA tool set remain the same as when it was first developed.

14.1.1.1 Underlying Data

The Esri ArcGIS network analysis application on which the PRIIA tool set is built enables the integration of many different types of data. The primary types of underlying data that are used to perform the simulations conducted as part of this assessment include the following:

- **Geospatial Data:** Geospatial data were collected from FEMA and from Commonwealth government data portals. These portals include the locations, names, and characteristics of both links and nodes in the systems that constitute the electric grid, water systems, intermodal transportation networks, road networks, and wired and wireless communications infrastructure.
- **Facility Characteristics:** Information on facility characteristics was provided by FEMA and various other federal and Commonwealth government agencies associated with the Infrastructure Systems Recovery Support Function team. These include the service and resource capacities of infrastructure assets (e.g., daily water treatment plant throughput) as well as other characteristics for certain infrastructure classes (e.g., the number of service connections to the electric grid).

14.1.1.2 Model Outputs

The PRIIA tool set simulations were used to identify potential propagations of cascading failures of dependent infrastructure resulting from electric power outages. However, several variables not captured in the PRIIA tool set would affect how these outages would impact infrastructure in real-world settings, including the potential for disruption and the benefits of mitigation, as follows:

- **Potential for Disruption:** The results from simulations are not definitive representations of how an electric power outage will disrupt dependent infrastructure. As noted in the methodology section (Section 14.1.0), the PRIIA tool set screens for the connections between infrastructure assets and highlights those connections that could be affected. The PRIIA tool set is not intended to produce a definitive, binary result of in- or out-of-service; rather, the result is intended to identify those infrastructure assets that are at potential risk of disruption and the possible consequences of the service area being impacted.
- **Benefits of Mitigation:** Many unique characteristics and circumstances may enable some infrastructure assets to mitigate the simulated outage were it to occur in reality. Mitigation approaches may include the installation of backup generators or uninterruptible power sources that would allow the infrastructure asset to continue operating at some level without externally provided electric power. Although the PRIIA tool set includes data on some infrastructure asset categories that have installed backup systems, those data are unavailable for most of the infrastructure asset types examined as part of this assessment and therefore are not used in the simulations.

14.1.1.2.1 State of the Existing Electric Grid

The PRIIA tool set simulates outages and their potential for cascading failures in the existing electric grid. The tool set was not used to explore how any specific investments in or transitions from the current configuration and characteristics of the existing electric grid might affect the potential for these results. Rather, the objective of using the tool set as part of PR100 is to illustrate which critical infrastructures depend on electric power, where these are located, and how these are connected to the existing electric grid for broader community resilience planning purposes. The results from the PRIIA tool set are derived from simulated disruptions at two points in the modeled subtransmission system (i.e., 38-kV system) serving local load centers:

- **Service Connections:** Simulations of the disruptions to subtransmission power lines that provide service connections to the critical infrastructure.
- **Supply Nodes:** Simulations of disruptions to distribution substations that are the closest node providing power to the critical infrastructure.

14.1.2 Results

The results from simulations using the PRIIA tool set provide insights into the dependencies and interdependencies that exist between the current electric grid and the Commonwealth's communications, transportation systems, and water infrastructure. These dependency mappings illustrate the potential downstream consequences that could impact community and regional levels in the event of an upstream outage of electric power leading to cascading failures in these other critical systems. The following subsections present an overview of these infrastructures and the characteristics of the connections between each infrastructure and the energy sector.

14.1.2.1 Communications

14.1.2.1.1 Sector Overview

The communications sector comprises private and public sector systems that provide voice, data, and broadcast services to industrial, commercial, governmental, and residential customers. Service provider networks are interconnected and leverage both wired line and wireless technologies to enable communication from broadcasts and between end users. Multiple service providers support communications in Puerto Rico and vary in size, coverage, functions, and services offered (FCC n.d.). Claro—the Commonwealth's incumbent local exchange telephone carrier supporting the public switched telephone network, along with AT&T, T-Mobile, Liberty, and Sprint—provide cellular telephone, data, and broadcast services across Puerto Rico.

The major components of commercial communications in Puerto Rico include the submarine cable system, Commonwealth-wide optical fiber backbones, data centers, exchange and switching facilities, metro optical fiber rings, microwave backhauls, cellular towers, and local wired and wireless services (FCC n.d.). This assessment focused on a selection of communications infrastructure assets that depend on electricity to connect and deliver voice, data, and broadcast services, which include the following:

- **Data Centers:** Facilities that house networked computing and storage resources that enable the sharing of digital applications and data and frequently include significant temperature control systems to ensure the preservation of computer equipment (also referred to as a telecoms hotel).

- **Exchange and Switching Facilities:** Facilities that house interconnections for voice and broadband data (also referred to as a central office).
- **Cellular Towers:** Networked antennas that send and receive voice and data between data centers, exchange and switching facilities, and cellular users; these may also include a staffed office from which the asset is managed.
- **Business Offices:** A variety of office spaces and control centers from which a utility's operations are managed.

14.1.2.1.2 Energy Dependencies of Communications Infrastructure Assets

Table 68 lists the communications infrastructure asset types along with the operations that have energy dependencies, the total number of each asset type serving communities in Puerto Rico, the percentage of each asset type that is powered by multiple service connections (i.e., power lines), and the percentage of each asset type that is connected to multiple supply nodes (i.e., substations) in the existing electric grid. The table also lists the character of the energy dependency; for conciseness, two kinds of dependencies are omitted: All four asset types require IT for monitoring equipment and facilitating operations, and all staffed assets require energy for health, safety, and security (e.g., lighting, alarms, and domestic needs). These are the only requirements for business offices; they apply to data centers, exchange and switching facilities, and some staffed cellular towers.

Table 68. Energy Dependencies of Communications Infrastructure Assets

Asset Type	Special Energy Dependency	Total Number	Multiple Service Connections	Multiple Supply Nodes
Data centers	Computer and server operations and connectivity Temperature control systems to remove heat or cool equipment	19	84%	63%
Exchange and switching facilities	Computer and digital switching operations and connectivity	8	75%	38%
Cellular towers	Antenna, transmitter, and receiver services and operations	2,710	≈10%	>1%
Business offices		20	70%	55%

The energy dependencies of these communications infrastructure assets illustrate several important considerations for energy infrastructure investments and planning:

- **Character of Energy Dependency:** All the communications infrastructure assets that have staffed offices depend on energy to ensure employees have access to healthy, safe, and secure workplaces. For the small share of cellular towers that also include a staffed office, those assets would have the same operational dependency on energy. All the communications

infrastructure assets are also equipped with systems to manage the asset and facilitate the connections or broadcast of data and information between the asset and consumers that depend on energy.
- **Multiple Service Connections and Supply Nodes:** Most communication infrastructure assets where significant computing and storage resources are located have multiple service connections and supply nodes. These redundancies are justified considering the need for stable energy service to ensure the uninterrupted operation of communications infrastructure equipment. Likely because of the sheer number across the Commonwealth, cellular towers were found to have only a small percentage connected by more than one power line, and virtually none was found to be connected to more than one substation.

The potential consequences of electric power outages causing cascading failures in dependent communications infrastructure assets could include wide-ranging impacts to all other critical infrastructure, community lifelines, public safety, and economic activities that depend on communications infrastructure, such as the following:

- **Colocated Infrastructure:** In addition to the interconnections between energy and communications infrastructure assets that provide power and transfer information, their distribution systems are also often colocated, which can create additional vulnerabilities. Wired communication lines and electric power lines often share rights-of-way on the same distribution poles, which add weight and reduce wind resistance to the poles and aerial lines that increase the potential for damage in high wind events. The result is an unnecessary geographic dependency between aerial electric power lines and wired communications: The degradation of one element (e.g., pole collapses or line cuts during maintenance and repair) may affect the operations of both electric grid and communications distribution systems (Cordova et al. 2021).
- **Public Safety:** The Puerto Rico State Police Department along with various municipal police departments, fire departments, and emergency medical services use various radio systems and a secure public safety network to coordinate incident response and respond to 911 calls. Some of these communications services are facilitated by the same commercial providers on the existing infrastructure assets and systems that connect all other communications. Although most first responders have redundant and alternative systems, a loss of electric power that affects communications infrastructure may slow response times (FCC n.d.).
- **Economic Activities:** Many economic activities depend on communications infrastructure. Business-to-business communications, business-to-consumer communications, payment processing, supply chains management, logistics, product manufacturing, banking and finance, and final shipping and delivery across numerous commercial and industrial sectors depend on communications infrastructure. For example, disruptions in communications will drastically reduce the capacity of the food industry to supply safe, reliable, and secure shipments during emergencies. The cascading failure of electric power outage resulting in failures in communications infrastructure required for economic activity may have a detrimental effect on individual businesses or lead to significant interruptions in overall economic productivity (GAO 2021).
- **Downstream Impacts to Communications-Dependent Infrastructure:** As infrastructure operations become increasingly digital, virtually all infrastructure sectors have increasingly critical dependencies on communications infrastructure. Efficiencies that are made possible through computer systems that monitor infrastructure and manage complex tasks all require

industrial control systems (ICS) and supervisory control and data acquisition (SCADA). Many of these operations are also replacing the manual alternatives to these digital processes, leaving the infrastructure asset or system possibly unable to operate without communications infrastructure. Because of the tight interdependency that they share, energy and communications infrastructures are widely viewed as both critical first- and second-order dependencies of all other infrastructure sectors (Cordova et al. 2021).

- **Impacts to Energy Infrastructure Due to its Interdependencies With Impacted Communications Infrastructure:** Energy and communications infrastructures share a critical interdependency: Operations across the existing electric grid require constant monitoring and are widely managed by remote command systems that are facilitated by communications infrastructure. Many management operations in the existing electric grid are supported by PREPA Networks (PrepaNet), a wholly owned subsidiary of PREPA, which is used to control substations and other field equipment of the utility. However, the PrepaNet infrastructure is a middle-mile provider that still depends on private sector data centers.

14.1.2.2 Transportation Systems

14.1.2.2.1 Sector Overview

The transportation systems sector comprises the air, maritime, and road networks that airports, seaports, and a network of roads use to facilitate the movement of people and goods. The energy dependencies of the road network are varied and dispersed across the Commonwealth. Although electric power outages may affect street lighting, traffic lights, toll systems, and other important supporting capabilities, the road transportation system does not rely on electric power as a critical dependency on the same level as the air and maritime transportation systems (DTOP n.d.). Accordingly, this assessment focuses on the energy dependencies of airports and seaports.

The air transportation system includes infrastructure assets that support passenger, freight, military, and recreational aircraft transporting people and cargo across the globe. The Puerto Rico Ports Authority operates 11 airports, several of which play a key role in transporting many essential consumable resources (e.g., consumer goods) and produced commodities (e.g., pharmaceuticals) that are critical to both societal functioning and the economy. San Juan's Luis Muñoz Marín International Airport dominates air cargo and passenger traffic in Puerto Rico, accounting for approximately 76% of the total value and 63% of the total weight of annual throughputs of air cargo in Puerto Rico. Rafael Hernández International Airport in Aguadilla has the longest runway in the region and is capable of handling some of the largest cargo aircraft in the world. Rafael Hernández facilitates approximately 23% of the total value and 37% of the total weight of total annual throughputs (PRPA n.d.).

The maritime transportation system includes seaport infrastructure assets that facilitate a critical enabling function for virtually all societal and economic activities in Puerto Rico. The Puerto Rico Ports Authority operates 11 seaports under Puerto Rico's Department of Transportation and Public Works that play a key role in the transport of numerous essential consumable resources (e.g., fuels, chemicals, machinery, electrical equipment, food, transport vehicles, consumer goods) and produced commodities (e.g., pharmaceuticals, medical devices, and equipment) (PRPA n.d.). The Port of the Americas Authority operates the twelfth seaport, the Port of Ponce. The three major seaports in Puerto Rico are the Port of San Juan, Port of Ponce, and Port of Fajardo, which together accounted for approximately 99% of the total value and weight of all annual foreign throughputs.

Most of this throughput transits the Port of San Juan—Puerto Rico's primary commercial port—handling most maritime cargo moving through the region's other seaports (DTOP n.d.).

Puerto Rico has a critical dependence on the air and maritime transportation systems because of its geography and location. The primary assets that constitute these infrastructures, which include the following, thus play a vital role in facilitating all supply chains for the Commonwealth:

- **Bulk and Breakbulk Terminals:** Docks, wharfs, and other facilities where loose and packaged commodities are loaded and unloaded from ships and airplanes.
- **Container Terminals:** Maritime facilities at the Port of San Juan and the Port of Ponce equipped with container cranes for loading and unloading container ships and barges.
- **Storage Facilities:** Facilities for warehousing goods upon receipt or pending shipment. These facilities range from refrigerated warehousing capacity to outdoor container yards where goods may be temporarily stored.
- **Material Handling Equipment:** Variety of gantry cranes and other transloading equipment that manages bulk, breakbulk, and containers at docks, wharfs, and other facilities. This equipment may also be used to facilitate intermodal transfers between trucks and ships.
- **Business Offices:** Variety of office spaces and control centers from which the operations of the utility are managed.

14.1.2.2.2 Energy Dependencies of Transportation Systems Infrastructure Assets

Table 69 lists the transportation systems infrastructure asset types along with the operations that have energy dependencies, the total number of each asset type serving communities in Puerto Rico, the percentage of each asset type that is powered by multiple service connections (i.e., power lines), and the percentage of each asset type that is connected to multiple supply nodes (i.e., substations) in the existing electric grid. As in Table 68, all staffed facilities require energy for the health, safety, and security of those working in them, and all asset types except material handling equipment require energy for communications, ID, and monitoring equipment. For both business offices and bulk and breakbulk terminals, these are the only requirements.

Table 69. Energy Dependencies of Transportation System Infrastructure Assets

Asset Type	Special Energy Dependency	Total Number	Multiple Service Connections	Multiple Supply Nodes
Bulk and breakbulk terminals		18	29%	14%
Container terminals	Container cranes, including the control systems and mechanical pulley system for lifts and turns Yard connections for powering refrigerated containers	3	66%	33%
Storage facilities	Refrigeration and temperature control for cold chain facilities	26	50%	10%
Material handling equipment	Power for gantry cranes and other fixed and mobile assets (many of which may alternatively use fuels)	Many	Depends on terminal	Depends on terminal
Business offices		31	23%	10%

The energy dependencies of these transportation systems infrastructure assets illustrate several important considerations for energy infrastructure investments and planning:

- **Character of Dependency:** Although many of the energy dependencies related to basic requirements and computer systems are common across these facilities, several of these assets have unique dependencies on externally provided electric power. Container cranes generally cannot be powered by any backup systems. These critical components of the maritime transportation system have no alternative other than to be powered by the electric grid. Material handling equipment includes a range of resources—some of which may require fuels as opposed to electricity (e.g., trucks used on-site at a terminal to manage store containers). As the availability of material handling equipment that is purely electric increases (e.g., electric trucks for on-site storage management), these facilities will need to be equipped with recharge stations to power the equipment, which will be a new feature and dependency (DTOP n.d.).
- **Multiple Service Connections:** Many of the most critical airport and seaport facilities have redundant electric power service connections. The bulk and breakbulk facilities that do not can continue at least some operations while electric power is degraded or disrupted if capabilities exist on the ships or planes to facilitate unloading or if fuel-based material handling equipment remains available during an outage.
- **Multiple Supply Nodes:** Only one of the maritime terminals at the Port of San Juan has a connection to more than one supply node. If an outage impacts a significant portion of metropolitan San Juan, leaving this port terminal as the only conduit for freight, the volume of material that may have to be moved through this maritime terminal would likely exceed the maximum throughput that it can sustain for a long period of time.

The potential consequences of cascading failures in electric power affecting interdependent transportation systems infrastructure assets could include degraded operations that drastically affect supply chains if airport and seaport assets are unable to function at required levels. These consequences could include the following:

- **Supply Chain Disruptions:** Puerto Rico has few alternatives to receiving critical supply chains through a small number of airports and seaports. The operators of these facilities have invested significant funding and effort into bolstering the resilience of these assets. If, however, a significant electric outage impacted freight operations at the Port of San Juan for a significant period of time, there is a risk that the backlog of freight movements would require a great deal of time to manage. Prioritizing the movement of those supply chains that are most critical to human health remains the primary goal of transportation system infrastructure planners in the event of an electric power outage that affects operations (Resnick et al. 2020).
- **Impacts to Energy Infrastructure Because of its Interdependencies with Impacted Transportation System Infrastructure:** In the existing electric grid, the fuel terminals that receive bulk petroleum shipments are critical to the operation of the grid (Resnick et al. 2020). As the renewable energy transition negates these dependencies on fuel, new dependencies on the flow of equipment and materials that are needed to manage or maintain the assets and system components of renewable energy infrastructure will be based on which infrastructure investments the Commonwealth's energy infrastructure operators choose to pursue.

14.1.2.3 Water

14.1.2.3.1 Sector Overview

Customers across Puerto Rico rely on the delivery of approximately 448 million gallons of treated water and the processing of approximately 206 million gallons of wastewater per day. More than 97% of this water is collected, treated, distributed, re-collected, retreated, and released by the Puerto Rico Aqueduct and Sewer Authority (PRASA) through 404 community water systems. Of these community water systems, 205 are sourced from groundwater accessed through wells and 199 systems are sourced from surface water along rivers, streams, lakes, and reservoirs. Only five of these community water systems serve more than 100,000 total customers, including the Metropolitano and Superacueducto water systems, which together satisfy the water and wastewater treatment requirements of more than one-third of Puerto Rico's population (PRASA n.d.).

In addition to the 404 community water systems that serve most people in the Commonwealth, there are 63 small private water systems. Of these, 56 are sourced from groundwater and 7 are sourced from surface water. These smaller private systems, residential sewage septic systems, and other localized services associated with these systems serve approximately 3% of the Commonwealth's water and wastewater treatment requirements (PRASA n.d.).These smaller private systems, residential sewage septic systems, and other localized services associated with these systems serve approximately 3% of the Commonwealth's water and wastewater treatment requirements (PRASA n.d.).

For those communities that are served by PRASA, the primary assets that constitute these infrastructures include the following:

- **Water Treatment Plants:** Stand-alone facilities where raw water collected from surface and subterranean sources is treated through a series of processes—including coagulation, flocculation, sedimentation, filtration, and disinfection—before being delivered directly to customers or to storage tanks for later distribution.
- **Pumping Stations:** Networked facilities that maintain pressure and water flow in pipelines. These also include raw water supply and intake facilities located at water reservoirs, river dams, intakes, and groundwater wells. These connect more than 14,000 miles of pipelines from raw water sources, through treatment systems and storage tanks, and finally to customers (PRASA n.d.).
- **Storage Tanks:** Temporary holding facilities that are usually colocated with pumping stations or water treatment plants.
- **Wastewater Treatment Plants:** Stand-alone facilities where wastewater (and, in some cases, storm water) is treated through a series of processes—including screening, sludge removal, sedimentation, aerating, and disinfection—before the effluent is discharged back into the environment.
- **Lift Stations:** Networked facilities that move wastewater from lower to higher elevations. These connect the nearly 6,000 miles of sewage pipeline linking customers to wastewater treatment plants throughout the Commonwealth (PRASA n.d.).
- **Business Offices:** Variety of office spaces and control centers from which the operations of the utility are managed.

14.1.2.3.2 Energy Dependencies of Water Infrastructure Assets

Table 70 lists the water infrastructure asset types along with the operations that have energy dependencies, the total number of each asset type serving communities in Puerto Rico, the percentage of each asset type that is powered by multiple service connections (i.e., power lines), and the percentage of each asset type that is connected to multiple supply nodes (i.e., substations) in the existing electric grid. As above, the table omits health, safety, security, and other requirements for staffed facilities and communications, IT, and monitoring equipment; both of these requirements apply to all asset types and are the only requirements for business offices and storage tanks.

Table 70. Energy Dependencies of Water Infrastructure Assets

Asset Type	Special Energy Dependency	Total Number	Multiple Service Connections	Multiple Supply Nodes
Water treatment plant	Pumping systems to move raw water through each phase of treatment to delivery network Chemical and material management systems through each phase of treatment Hydraulic systems to maintain pressure in treatment systems	114	38%	16%
Pumping stations	Hydraulic systems to maintain pressure across transmission	917	3%	>1%
Storage tanks		2,168	>1%	0%
Wastewater treatment plant	Pumping systems to move influent water through each phase of treatment to effluent discharge Chemical and material management systems through each phase of treatment Aeration systems to push oxygen into water during treatment Lighting systems to facilitate ultraviolet disinfection	51	26%	12%
Lift stations	Hydraulic systems to maintain pressure across transmission	715	>1%	0%
Business offices		12	33%	17%

The energy dependencies of these water infrastructure assets illustrate several important considerations for energy infrastructure investments and planning:

- **Character of Dependency:** All these water infrastructure assets depend on energy to ensure employees have access to healthy, safe, and secure workplaces. These energy-dependent workplace requirements are common across all the critical infrastructure assets examined in this assessment as well as virtually every other commercial and industrial workplace in

Puerto Rico and the 50 U.S. states. All the water infrastructure assets are also equipped with systems to manage the assets that also depend on energy, which may range from basic control systems to make adjustments in operation to advanced SCADA and other enterprise management systems. The characters of dependency in the potable water treatment and in the wastewater treatment phases are generally similar to one another considering the parallel processes that are facilitated before and after customer use of water (PRASA n.d.).

- **Multiple Service Connections:** Few of the pumping stations, storage tanks, and lift stations examined were found to have multiple service connections. For these assets, the disruption of the sole connection and/or substation providing power is a potential single point of failure for the asset's operations. Slightly more than one-third of the water treatment plants and one-quarter of the wastewater treatment plants were found to have redundant service connections to one or more substations. Several PRASA business offices were found to be located in areas with redundant service connections, particularly those in the metropolitan San Juan area. Although these redundancies are beneficial in ensuring greater resilience if there is an issue with one of the actual power line connections, where the redundant service connections originate from a single supply node, the risk remains that a disruption at a substation or to a transformer is a potential single point of failure for those facilities.
- **Multiple Supply Nodes:** The water and wastewater treatment plants that are connected to multiple supply nodes are located near urban centers in the Metropolitano, Superacueducto, Mayagüez, and Ponce Urbano community water systems, where there is a greater density of substations. Although these include several of the plants that serve the largest populations, the overall percentage of the Commonwealth's treatment capacities that has been bolstered in resilience by being connected to multiple supply nodes remains small. Very few pumping stations and no known lift stations or storage tanks have redundant supply node connections, and only two of the business offices that oversee utility operations are connected to more than one substation (PRASA n.d.).

The potential consequences of cascading failures in electric power affecting dependent water infrastructure assets could include degraded operations, physical damage, or mandatory shutdown requirements if the water infrastructure cannot function at required levels. These consequences could include the following:

- **Backup Power:** Most pumping stations, storage tanks, and lift stations were not reported to have backup power. Although many of these asset types may be temporarily powered by mobile backup generators, recent events such as Hurricane Fiona have demonstrated that allocating finite resources for these asset types remains a challenge (PRASA n.d.). In other instances, neither mobile nor currently installed backup generation may be sufficient to power all of an asset's operations, allowing only a subset of activities or reduced operations to continue. Even for those equipped with backup generators, the assets may be capable of continuing at degraded operations only for as long as fuel supplies are available for those backup generators.
- **Loss of Capabilities and Capacities to Meet Needs:** Electric outages that result in degraded electric power service or require operations to be switched to backup generation may result in water and wastewater treatment plants being unable to complete one or more of the necessary steps in treatment processes. If each step remains achievable but at lower overall output, the reduced quantity of treated water that may be available because of degraded electric power

service slowing the process within the plant may not satisfy the downstream needs of the communities the plant serves.

- **Loss of Pressure that Delays Restoration or Causes Damage:** Electric outages that affect pumping station capabilities to maintain pressure in the distribution of treated water could result in the backwash of water that causes contamination within the distribution pipeline network. Drops in pressure across the pipeline network can also cause pipes to crack—releasing water, further contaminating the pipelines, and eventually requiring the repair and replacement of those segments of the pipeline network (PRASA n.d.).
- **Corporate or Regulatory Mandate to Shut Down:** PRASA is subject to numerous federal, Commonwealth, and self-imposed corporate requirements related to operational standards in the resulting quality and quantity of water services it provides. A lapse in electric power that disrupts or degrades operations in the infrastructure assets may require that community water systems shut down so that repairs can be made or until operations can resume at a required level of capabilities or capacities. The loss of monitoring and control systems in particular may cause PRASA to shut down operations until the system can be effectively managed.
- **Downstream Impacts to Water-Dependent Infrastructure and Community Services:** All infrastructure sectors and community services have some level of dependency on water infrastructure. For industrial processes in manufacturing, medical care, commercial food preparation, domestic office requirements, equipment cooling, and all sanitation processes, water service is a critical dependency for most societal functions. A cascading failure in energy and water infrastructure will have broad downstream consequences across impacted communities.
- **Impacts to Energy Infrastructure Due To Its Interdependencies With Impacted Water Infrastructure:** In addition to all other downstream infrastructure sectors and numerous other community services that depend on water service, energy infrastructure assets themselves have dependencies on water infrastructure. Any energy infrastructure assets that require cooling, for example, will require service from local water infrastructure assets. Even as thermal generation capacity—which in most cases includes cooling towers—is replaced with renewable energy sources, the systems by which energy infrastructure assets are controlled and the facilities where these are located will continue to depend on interdependent water infrastructure assets (PREPA n.d.).

Analyzing dependencies and interdependencies identifies the level and complexity of connections across infrastructure sectors and elucidates how these assets and systems operate in concert to fulfill the needs of a community or region (Rinaldi, Peerenboom, and Kelly 2001). The number and nature of a community or region's needs for electric power service are many and diverse, including virtually all community lifelines, societal functions, economic activities, and household needs. These local perspectives of how energy satisfies basic life-sustaining requirements in a community are the focus of the complementary social burden analysis that was conducted as part of PR100. The infrastructure interdependency assessment serves as an input to that analysis by providing a regional view of how electric power outages may cascade across regions and between communities. This assessment is intended to illustrate how the potential for a disruption that increases the costs—financial and otherwise—associated with an outage, such as the need to travel far from one's home to secure basic requirements, might be further exacerbated by broader cascading failures that require even greater costs. Section 14.2 provides an in-depth discussion of the social burden analysis.

14.1.3 Interpretation

The operations of communications, transportation systems, and water infrastructure are essential to societal functioning. Their vital interdependencies with energy infrastructure require that these lifeline infrastructures be prioritized as critical demand nodes in the planning for and investments made in the renewable energy transition. The assessment of interdependencies developed as part of PR100 can be leveraged to drive specific renewable energy projects that bolster the reliability and resilience of both the energy sector and these interdependent infrastructures. This analysis indicates that designing energy infrastructure systems to include redundancies in the service connections and supply nodes that provide electric power to interdependent infrastructure can mitigate the potential for cascading failures that could intensify the consequences of an outage.

A lack of redundancies in energy infrastructure systems creates the potential for a downed power line, damaged transformer, or disrupted substation to manifest as a single point of failure for all downstream customers. For critical infrastructure customers, these failures may cascade into broader impacts as the services or resources that they provide are degraded or disrupted (e.g., a community's potable water supply). For affected infrastructures that also share interdependencies with the energy sector itself, these impacts might escalate into a disruption of services or resources required by the energy infrastructure (e.g., ICS and SCADA), complicating the processes required for electric power restoration. Building redundancies into an energy system is a proactive measure to bolster the resilience of interdependent infrastructure and, therefore, the energy infrastructure system.

14.1.3.1 Communications Infrastructure

Although energy infrastructure provides the electric power needed for operating assets and systems across the communications sector, communication assets and systems also support the monitoring and control operations of the electric grid. Communications infrastructure—including approximately 84% of data centers, 75% of exchange and switching facilities, and one-tenth of all cellular towers—face the risk of disruptions due to the loss of a single service connection or supply node. Disruptions of communications infrastructure service will, in turn, impact the ICS and SCADA systems required to manage the operation of energy infrastructure assets and systems (FCC n.d.; PREPA n.d.).

14.1.3.2 Transportation Systems Infrastructure

Air, maritime, and road transportation systems facilitate the mobility of people and goods to, from, and across the Commonwealth. The total portfolio of Puerto Rico's critical supply chains is handled by 11 airports and 11 seaports operating container cranes, material handling equipment, and storage facilities as well as vessel and air traffic control systems that have critical dependencies on externally provided electric power. These intermodal facilities are also critical to the receipt and movement of equipment and materials that are required for the operation and maintenance of all other infrastructure, including energy infrastructure assets and systems. The loss of these facilities would halt the movement of 99% of all annual throughputs sent and received from outside the Commonwealth, including critical food, fuel, and medical supplies (DTOP, 2022).

14.1.3.3 Water Infrastructure

The treatment plants, pumping stations, lift stations, and pipelines that distribute potable water and manage wastewater have numerous dependencies on electric power to support sanitation processes and maintain pressure throughout the network. The thermal generation capacity of the existing electric grid has significant dependencies on water for cooling towers. Although the decommissioning of these generation plants will reduce the energy sector's overall dependency on water service, the assets and system components of renewable energy infrastructure will also depend on water service for equipment cooling, fire suppression, and the domestic needs of staffed facilities. Approximately 38% of all water treatment plants and 26% of all wastewater treatment plants have only one service connection or supply nodes for electric power, creating significant risks that disruptions to these energy infrastructure would impact the ability of these water infrastructure to provide services to their communities (PRASA n.d.; PREPA n.d.).

14.1.3.4 Redundant Service Connections

Virtually all the distribution-level assets that comprise the communications and water infrastructure systems (e.g., cellular towers and pumping stations) have only one service connection providing electric power (FCC n.d.; PRASA n.d.; PREPA n.d.). This is a result of the sheer number of these assets and their geographic dispersion throughout the Commonwealth (FCC n.d.; PRASA n.d.; PREPA n.d.). This is a result of the sheer number of these assets and their geographic dispersion throughout the Commonwealth. Elements above the distribution level fare better: Most data centers and core offices of the communications sector and the freight terminals of the transportation systems sector—as well as a significant portion of the water and wastewater treatment plants—have multiple service connections. However, the delivery networks are nevertheless at a higher risk of disruption because of the single points of failure in electric power service connections to the distribution-level assets.

14.1.3.5 Multiple Supply Nodes

Many infrastructure asset types are connected to only a single supply node. Data centers and core offices are the exception; they are generally powered by multiple service connections, and most of these are also served by more than one supply node (i.e., distribution substation). These assets are generally situated in dense metropolitan areas where there is a correspondingly larger and more proximately located number of substations. Most other infrastructure asset types examined as part of this assessment were connected only to a single supply node. In addition, for many of the infrastructure assets connected to multiple service connections as described above, these connections all originated from a single supply node. The redundancy of service connections helps ensure resilience, but it carries the same level of risk posed by a single transformer or substation disruption causing an outage along all the service connections that it powers (Busby et al. 2021).

Designing an energy infrastructure system that promotes resilience requires that interdependent infrastructures that are prioritized as critical demand nodes have redundant service and supply coverage. The identification of interdependent infrastructure assets that do not have these redundant service connections or multiple supply nodes in the current configuration of the electric grid developed as part of this assessment can be used to map out how new energy infrastructure assets and systems might fill the deficits in redundant service and supply coverage for these important customers. Forming and strengthening partnerships between energy and interdependent infrastructure operators could facilitate a collaborative forum for joint efforts to address common challenges in gaps and deficiencies in the provision of electric power service across the Commonwealth.

Partnership between the energy and interdependent infrastructure sectors will be a crucial feature of the new energy landscape developing in Puerto Rico. The stakeholder engagement facilitated as part of PR100 could serve as a model for such coordination and collaboration.[191] The process of determining which infrastructure assets to prioritize as critical demand nodes or how the design of redundancies could best support broader resilience as suggested above would ideally be driven by partnerships across the Commonwealth's infrastructure community. These forums are also opportunities to address emerging and persistent challenges that interdependent infrastructure operators experience in terms of gaps and deficiencies in the provision of electric power service that affect their operations and resilience. Some of these challenges include voltage instability, transmission-level customers, and backup and restoration needs.

14.1.3.6 Voltage Instability

Infrastructure operators throughout Puerto Rico have reported chronic instability issues related to voltage variability. Voltage generally remains within 2%–5% variability across most systems in the United States, but stakeholders across Puerto Rico reported variability ranges of 12%–15% during peak demand periods (COR3 2019a). Although many infrastructure assets and system components are equipped with uninterruptible power sources and backup generators that can mitigate the effects of voltage instability, fluctuations in service for infrastructure assets and systems that facilitate heavily energy-dependent processes that are difficult to sustain using backup power generation—such as water treatment processes or data center operations—may disrupt these operations.

14.1.3.7 Transmission-Level Customers

Within transportation systems in particular, infrastructure assets that facilitate intermodal transfer, such as container cranes at the maritime port terminals, are transmission-level customers of electric power (DTOP n.d.). These facilities have unique requirements in terms of voltage that must be ensured and maintained during operations. Including these unique requirements in the planning and investment of new energy infrastructure, and revisiting them through frequent collaborations, can ensure these unique demand nodes are included in energy infrastructure assurance planning.

14.1.3.8 Backup and Restoration Needs

Many transmission-level customers are unable to sustain operations using backup power generation because of the relatively greater electric power requirements of their facilities or equipment (PREPA n.d.). For this reason, it could be highly beneficial for energy infrastructure operators to develop a broader understanding of which interdependent infrastructure assets and systems can run on backup power generation, at what level of degradation, and for what period of time before a shutdown would be required. It could also be beneficial for the energy infrastructure operators to develop an understanding of the restoration needs for interdependent infrastructure as part of joint emergency preparedness efforts. This collaboration will ensure the

[191] "Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study (PR100)," DOE, accessed 2023, https://www.energy.gov/gdo/puerto-rico-grid-resilience-and-transitions-100-renewable-energy-study-pr100.

energy infrastructure operators understand how interdependent infrastructure services and resources that are critical to their operations will be brought back online and how the operators might better support these processes in terms of electric power requirements.

Regular meetings between energy and interdependent infrastructure operators in Puerto Rico to discuss concerns and challenges around reliability and resilience could build a common operating picture of their interdependencies. An organizing philosophy of this collaboration could be that the Commonwealth's infrastructure community are partners in managing a system-of-systems for communities across Puerto Rico. The engagement facilitated as part of PR100 along with interdependency assessment results it has produced may support the development of this collaborative forum by the infrastructure community. Additional ongoing assessments by interdependent infrastructure sectors, including the energy sector, can help account for shifting needs and emerging challenges that may affect their operations and require joint efforts across the new renewable energy infrastructure landscape.

The renewable energy transition has the potential to fundamentally transform critical infrastructure across the Commonwealth. The operational requirements, performance criteria, supply chains, challenges of interagency coordination, and the nature of interdependencies among all infrastructure assets and systems may require the adoption of new management approaches, technologies, and designs to account for shifting needs and emerging challenges in the new renewable energy infrastructure landscape.[192] Communications, transportation systems, and water infrastructure are as critical to societal functioning as energy infrastructure, and a broader assessment of these interdependent infrastructures could ultimately support future efforts to foster greater reliability and resilience in future energy infrastructure assets and systems.

Following are several specific domains in which changes will present challenges:

- **Advanced Technologies in Communications Infrastructure:** The expanding use of communications infrastructure to manage the operations of energy infrastructure assets and systems has been driven by technological advancements (e.g., improvements in remote monitoring for sensing capabilities) as well as increasing needs for situational awareness of operational conditions because of more diverse and complex grid characteristics (i.e., increasing distributed generation, smart metering, variable renewable generation, and demand management) (Zhao et al. 2023). Renewable energy infrastructure will require these and other advanced applications of communications infrastructure to support operations. Additional assessments of how these applications could best be integrated while satisfying the communication sector's other operational requirements and dependencies could be beneficial.
- **Significant Demand Nodes in Transportation Systems Infrastructure:** Assets managed by airports and seaports that are critical to supply chains may require relatively greater weight in the prioritization of demand nodes. The transportation systems sector has few—if any—alternatives to the container cranes at maritime port terminals and air traffic control facilities in the event of disruption to the facilities themselves or their dependencies on externally provided electric power (DTOP n.d.). Elucidating how these air and maritime

[192] "The Promise and Pitfalls of the Clean Energy Transition," The Wilson Center, by Jerry Harr, April 20, 2023, https://www.wilsoncenter.org/article/promise-and-pitfalls-clean-energy-transition.

transportation system infrastructures operate, including their requirements for voltages associated with transmission-level service, is likely to be a critical issue for the Commonwealth's infrastructure community to incorporate into future investments and joint planning efforts.(DTOP n.d.). Elucidating how these air and maritime transportation system infrastructures operate, including their requirements for voltages associated with transmission-level service, is likely to be a critical issue for the Commonwealth's infrastructure community to incorporate into future investments and joint planning efforts.

- **Climate-Driven Stress on Water Resources and Infrastructure:** Although all critical infrastructure faces the potential risks associated with climate-driven stresses that might affect their operations, by its nature, water resources and infrastructure will encounter both acute and chronic challenges because of shifting dynamic in the Commonwealth's climate over the coming decades (Section 4.1). Treating and storing water and managing extreme events such as severe storms and drought mean that the 467 water systems across the Commonwealth may require unique water resource management, hazard mitigation efforts, and, accordingly, new electric power specifications to deliver life-sustaining water service to these communities.

Undertaking asset- and system-level assessments of interdependent infrastructure across the Commonwealth could help the infrastructure community build a better understanding of its operations, dependencies, customers, hazards, vulnerabilities, threats, risks, and resilience. These assessments could also inform the construction of new and maintenance of existing energy infrastructure where these assets and systems fulfill the energy dependencies of other critical infrastructure.

14.1.4 Energy Justice Implications

A clear and prominent connection links this analysis with distributive justice, which focuses on how the benefits and burdens of the energy system are distributed across a society. Assessing infrastructure interdependencies provides insights into the characteristics of and interactions among multiple systems that are critical for a community's health, safety, resilience, and opportunity. Along with the related social burden analysis, we conducted this assessment to explore how communities with energy justice concerns may experience greater impacts during outages because of cascading failures in interdependent infrastructure that may scale up a crisis.

Energy infrastructure satisfies a critical enabling function for virtually all other infrastructure assets and systems. Decisions that have been made by energy infrastructure operators and planners have influenced the decisions of interdependent infrastructure operators and planners because of the need to design around the availability of critical upstream services that their assets and systems will require in order to operate. This may be the result of communities that have historically been the recipients of less investment than others. Alternatively, this may be the result of interdependent infrastructure operators making the determination that, although an investment would be beneficial, not enough service-level connections, supply nodes, or other investments have been made by the energy infrastructure operator to support the new interdependent infrastructure. Whether for one of these or another related reasons, in communities where there are fewer energy infrastructure assets and system components, there is a corresponding lack of interdependent infrastructure assets and system components. Thus, disparities in access to reliable and resilient energy infrastructure beget disparities in access to other infrastructure services and resources.

The connections to procedural, recognition, restorative, and ultimately transformative justice are implicit in the content and outcome of this analysis. Neither this individual assessment nor the PR100 project as a whole are intended to supplant the local perspectives and decision-making needed to support a just transition to a renewable energy future for Puerto Rico. It is the prerogative of community stakeholders throughout Puerto Rico to lead the discussions around their own energy justice concerns; this is a key principle of recognition justice. Rather, the goal of this assessment and others that are part of PR100 is to equip local stakeholders with a quantitative basis with which to describe the disparities in equal access and unfair burdens that they experience. These quantifications of how disparities in energy infrastructure beget disparities in other infrastructure services and resources may assist local communities in their discussions with critical infrastructure operators by illustrating the system science of how these inequities impact their lives. These assessments can also serve as the basis for comparative assessments of how some communities in Puerto Rico have measurably fewer investments in these critical infrastructures that deprive those communities of the services and resources needed to guarantee an equal level of health, safety, resilience, and opportunity across the Commonwealth.

14.2 Social Burden Evaluation

We conducted a social burden evaluation for the archipelago of Puerto Rico. Social burden evaluation is a core capability of Sandia National Laboratories Resilient Node Cluster Analysis Tool (ReNCAT) toolkit of grid resilience tools (Wachtel, Melander, and Hart 2022) and has been run as a stand-alone evaluation for PR100. ReNCAT is a publicly available desktop application; the ReNCAT toolkit also includes a QGIS plugin to calculate social burden.[193] At a high level, social burden is a measure of the hardship residents experience when trying to access and obtain critical services (e.g., food, water, medication, and communications). This hardship is calculated by measuring the effort an individual spends getting to a critical service, divided by their ability to procure that service. Detailed information about social burden's formulation can be found in Wachtel, Melander, and Jeffers (2022).

Social burden can be calculated to capture the impacts of a grid outage on critical services, as is typical after a natural disaster or other emergency event (black-sky) or to represent normal day-to-day grid operations (blue-sky) to assess a baseline state. Social burden could also be used to explore the compounding resilience impacts of cascading outages identified by the infrastructure interdependency assessment described in Section 14.1 (page 541), though that remains as future work.

In this baseline analysis, which we conducted at the census-block-group level, we used distance to represent effort, and median household income from census data to represent ability. Social burden also accounts for where critical infrastructure assets are located and the portion of various service types they provide. This analysis focuses on grid-tied critical infrastructure assets that provide services to Puerto Rico residents and includes 42 infrastructure types and 15 service types. Results are generally provided for overall social burden, which is obtained by summing the burdens across every included service type—though we can also look at burden for an individual service type.

[193] "Resilience Modeling and Tools," DOE, https://www.energy.gov/oe/resilience-modeling-tools; "QGIS-social-burden-plugin," https://github.com/sandialabs/QGIS-social-burden-plugin.

Social burden was selected as the metric for this evaluation because of its unique abilities to tie population demographic data to infrastructure assets and the critical services they provide and to change as the state of infrastructure assets changes because of threats and grid outages. The strengths of using the social burden metric to evaluate equitable service availability in Puerto Rico are that it is spatially explicit (both inputs and results are related to a specific geographic location and can be mapped), is consistent (the same metric structure has been used in approximately 20 communities in the 50 U.S. states and Puerto Rico), is adaptable (critical infrastructure and services are customized for Puerto Rico), uses community input, and is scalable (we looked at census block groups, municipalities, and the entire archipelago).

We evaluated other metrics as part of PR100 such as the Centers for Disease Control and Prevention (CDC) Social Vulnerability Index (SVI),[194] the Justice40[195] Climate and Economic Justice Screening Tool (CEJST),[196] and the Energy Justice Metric (Heffron, McCauley, and Rubens 2018; Romero-Lankao and Nobler 2021) to understand similarities and differences to social burden. These metrics primarily rely on census and economic data that produce a static evaluation of an area, always at a less granular scale (census tract or country level) than social burden. However, because the metrics do not consider ties to infrastructure, services, and the distribution system and therefore cannot be used to evaluate potential grid investments or impacts of disruptions, they do not predict and cannot be used to measure outcomes. These metrics can be used as screening tools to complement the type of analysis provided by a social burden evaluation. Some of the composite metrics may also be candidates for use as the attainment factor in social burden. Future work could explore the feasibility of this approach.

14.2.1 Methodology

14.2.1.1 Baseline Parameters and Inputs

We conducted a social burden assessment for the entire Commonwealth of Puerto Rico. The analysis uses a spatial resolution of census block groups, of which there are 2,555. Census block groups were selected because they allow users to detect service and economic variation when exploring the archipelago as a whole or while examining smaller regional areas such as municipalities.

The population demographics used in the social burden calculation were obtained from the U.S. Census Bureau's 2020 American Community Survey 5-yr estimates[197] and were also specified at the census-block-group level of resolution. The population data[198] for each census block group were used to scale per capita social burden to obtain a total social burden score. Both per capita

[194] "CDC/ATSDR Social Vulnerability Index," Agency for Toxic Substances and Disease Registry (ATSDR), https://www.atsdr.cdc.gov/placeandhealth/svi/index.html.
[195] "Justice40: A Whole-of-government Initiative, White House, https://www.whitehouse.gov/environmentaljustice/justice40/.
[196] "Climate and Economic Justice Screening Tool, White House Council on Environmental Quality, https://screeningtool.geoplatform.gov/en/
[197] https://data.census.gov/
[198] American Community Survey: B01003: Total Population: 2020: ACS 5-Year Estimates Detailed Tables, https://data.census.gov/table/ACSDT5Y2020.B01003?q=United+States&t=Population+Total&g=010XX00US_040XX00US72,72$1500000&y=2020.

and population-scaled results are provided. The median household income[199] for each census block group was used as the attainment factor for ability in the social burden equation. Other economic factors, or composites of census variables, may be used instead of median household income in future studies if warranted. Note that many census variables are provided at the census tract level, which is one level of spatial granularity higher than census block groups and therefore does not provide sufficient insight into regional variation.

The baseline social burden assessment includes 42 infrastructure sectors as shown in Figure 413. These sectors were identified as providing critical services to residents of Puerto Rico communities through previous work with planners, universities, stakeholders, community organizations, and other leaders with local knowledge—starting with an analysis after Hurricane Maria (Jeffers et al. 2018) and continuing over subsequent projects. Each sector listed contains multiple individual infrastructure assets.

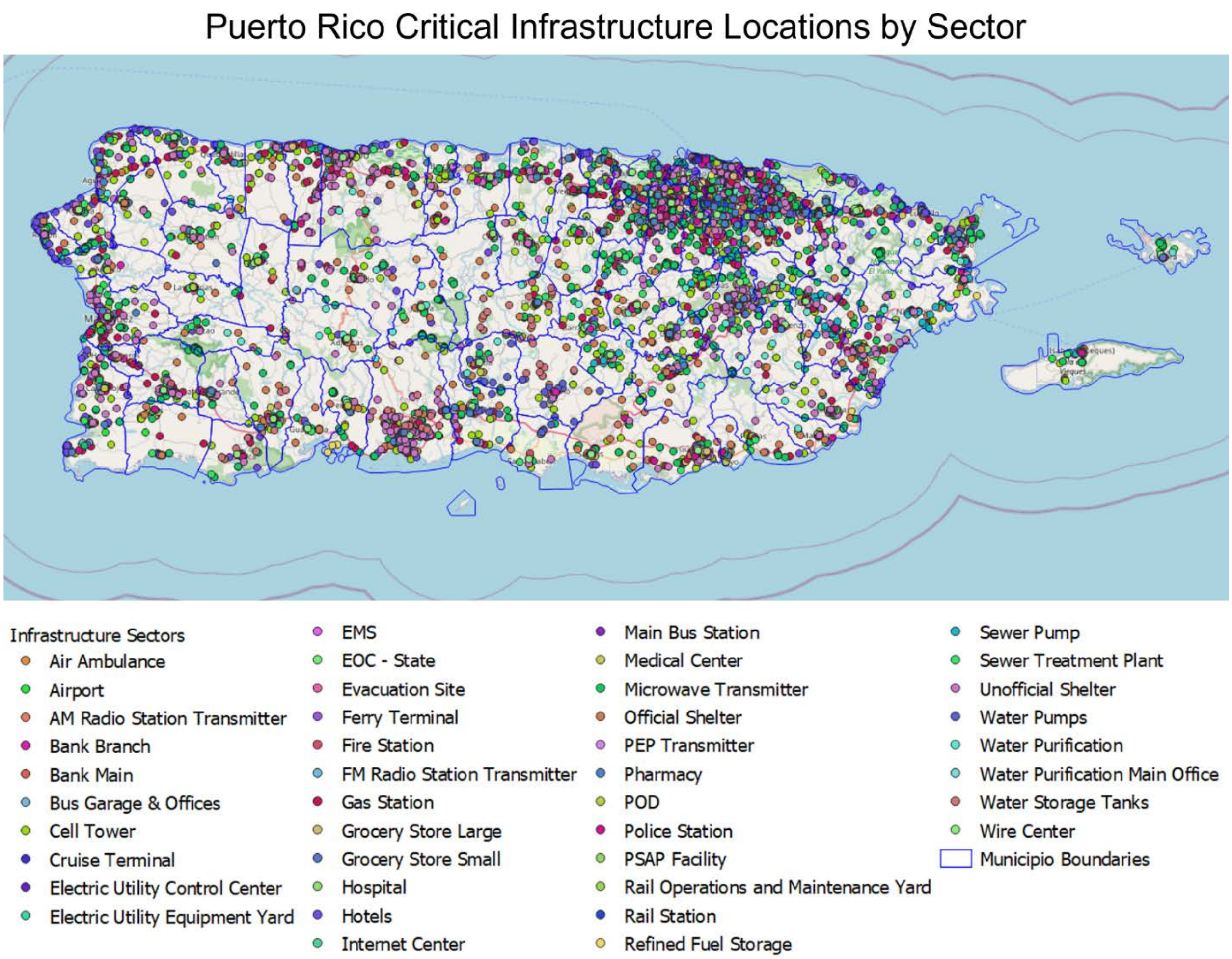

Figure 412. Infrastructure sectors and asset locations in Puerto Rico

[199] American Community Survey: B19013: Median Household Income in the Past 12 Months (in 2020 Inflation-Adjusted Dollars): 2020: ACS 5-Year Estimates Detailed Tables, https://data.census.gov/table/ACSDT5Y2020.B01003?q=United+States&t=Population+Total&g=010XX00US_040XX00US72,72$1500000&y=2020.

Similarly, the PR100 project teams worked with stakeholders to identify 15 service types deemed critical to residents during normal day-to-day life and especially during widespread grid outages that result from destructive events. The 15 service types are listed in Figure 414. Individual municipalities and communities may wish to look at a subset of these services or specify services unique to their community. Such an analysis would need to be the focus of future work.

Figure 413. Critical services for the social burden analysis in Puerto Rico

14.2.1.2 Included Threats and Anticipated Impacts

In addition to the baseline social burden assessment, plausible natural threats and their anticipated impacts on the archipelago were evaluated. For Puerto Rico, the top natural threats are flooding, landslides, earthquakes, and high wind. Analysis of wind impact was not included in this study because predicting electrical system damage to determine unpowered infrastructure assets was outside the scope of this study. For flooding, landslides, and earthquakes, each threat was assessed individually, and two additional scenarios were run to evaluate the combinations of these threats. The scenarios, cut-off criteria, and data sources are listed in Table 71.

Table 71. Threat Scenarios for the Social Burden Analysis

Scenario	Cut-Off Criteria	Data Source
100-Year Flood	In Flood Zone	FEMA Flood Insurance Rate Maps ("Flood Map Products," FEMA, https://www.fema.gov/flood-maps/products-tools/products)
500-Year Flood	In Flood Zone	FEMA Flood Insurance Rate Maps ("Flood Map Products," FEMA, https://www.fema.gov/flood-maps/products-tools/products)
Landslide Medium	≥ Medium Susceptibility	U.S. Geological Survey (USGS)
Landslide High	≥ High Susceptibility	USGS
Earthquake	High Damage Zone	USGS, Puerto Rico Seismic Network, University of Puerto Rico at Mayagüez (Cabezudo et al. 2022)
Risk Accepting	Combination of 100-Year Flood, Landslide High, and Earthquake	
Risk Averse	Combination of 500-Year Flood, Landslide Medium, and Earthquake	

The earthquake data were generated by the University of Puerto Rico at Mayagüez using Kriging interpolation methods and include data from USGS and the Puerto Rico Seismic Network[200] as part of an effort to model potential microgrid locations in disadvantaged communities in Puerto Rico (Cabezudo et al. 2022). Notably, the data set included the January 2020 6.4- and 6.0-magnitude earthquakes and corresponding aftershocks, providing an updated assessment of anticipated impacts in the southwest region of the Commonwealth.

The social burden analysis does not capture anticipated impacts to individual infrastructure assets as would be the case if we used fragility curves. Instead, the analysis aims to capture the practical impacts of a threat's aftermath. For example, if a building that provides a critical service is surrounded by 2 or more feet of water, a resident will not be able to get to that building to access the service. The building may still have power and be operational, but its power status is irrelevant if residents cannot access the location. For the cut-off criteria listed in the table, any facilities in zones in or above the cut-off point are considered unavailable for this reason. The services they had previously contributed to the area are omitted from consideration, and the overall social burden rises because residents have fewer providers for critical services. Infrastructure assets located outside the cut-off zones are considered to still have power and be providing services. This represents a best-case situation for each threat scenario because realistically, other parts of the grid or other infrastructure assets outside the cut-off zones could be damaged by secondary impacts of the event and unable to provide services.

14.2.2 Summary of Results

14.2.2.1 Baseline Social Burden Assessment

The maps shown in Figure 414 (page 564) and Figure 415 (page 566) represent the overall social burden (across all service types) by census block group for a blue-sky scenario in which all existing critical infrastructure is powered, operating, and serving its communities. Municipalities are outlined in blue for reference, and census block groups that were missing census data are shown in green. Figure 414 shows overall social burden per capita. Individuals living in census block groups with higher overall per capita burden experience a higher burden when trying to access and acquire critical services. Figure 415 shows total overall social burden, which is calculated by multiplying the per capita social burden for a given census block group by the number of people living in that census block group.

Note that the scale used for all maps was determined by the threat scenario with the highest social burden value, which was the Risk Averse scenario. The bins for the maps were determined by using the Natural Breaks (Jenks) option in QGIS for the Risk Averse scenario. These same bins were then used across the entire set of mapped results to allow for comparisons with the baseline and other threat scenarios. These bins are different from those used for the Year 1 results and allow for easier interpretation of relative burden.

Social burden results were also generated for each municipality at the census block level for both per capita social burden and total social burden scaled by the population. These municipality-level social burden maps can be viewed in the online data viewer. It is also possible to use the

[200] Puerto Rico Seismic Network (PRSN), https://redsismica.uprm.edu/.

data generated by this assessment to look at individual service types, though results by service were not produced for the report.

Lastly, the histograms in Figure 417 provide high-level information about the distribution of social burden values in the archipelago. The left and center histograms show the number of census block groups at different social burden levels for total burden and per capita burden, respectively. Although 98.8% of the census block groups have a total social burden under 18.4, the remaining 1.2% of census block groups experience social burden values ranging from 18.4 to more than 60. Census block groups with high baseline social burden values are ones that lack adequate access to one or more services during normal grid operations. The histogram on the right shows the number of people experiencing different levels of social burden on an individual basis. Similar to the census block groups, 98.4% of individuals experience a per capita social burden value less than 0.01, but the remaining 1.6% experience social burden values ranging from 0.01 to 0.035.

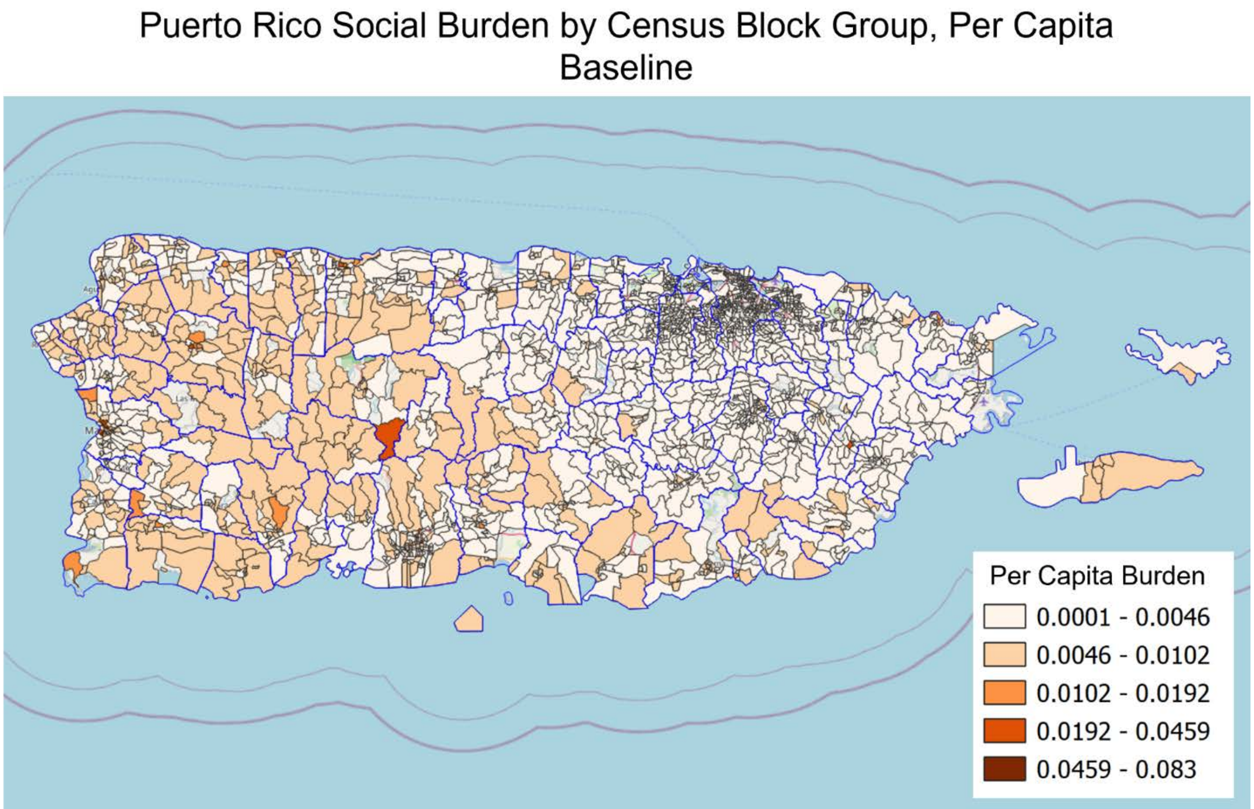

Figure 414. Baseline Puerto Rico social burden by census block group, per capita

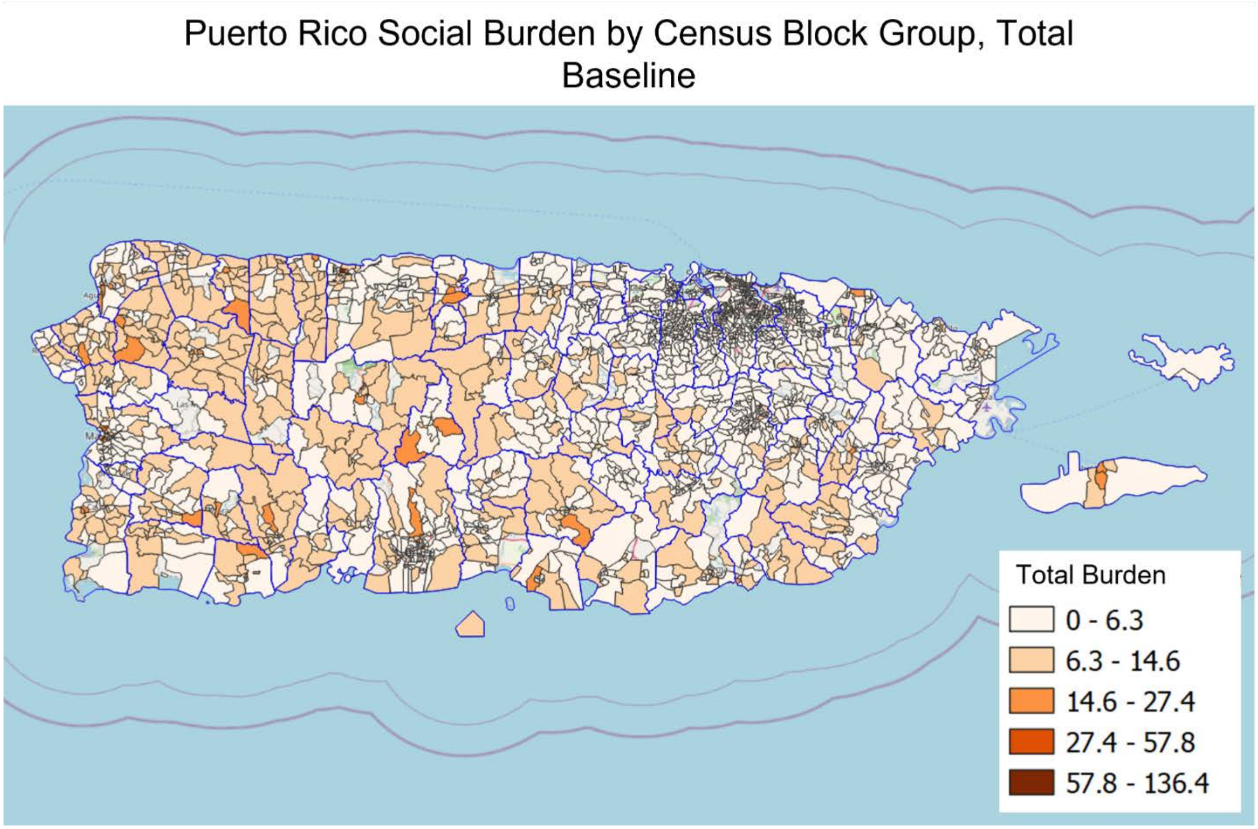

Figure 415. Baseline Puerto Rico social burden by census block group, total

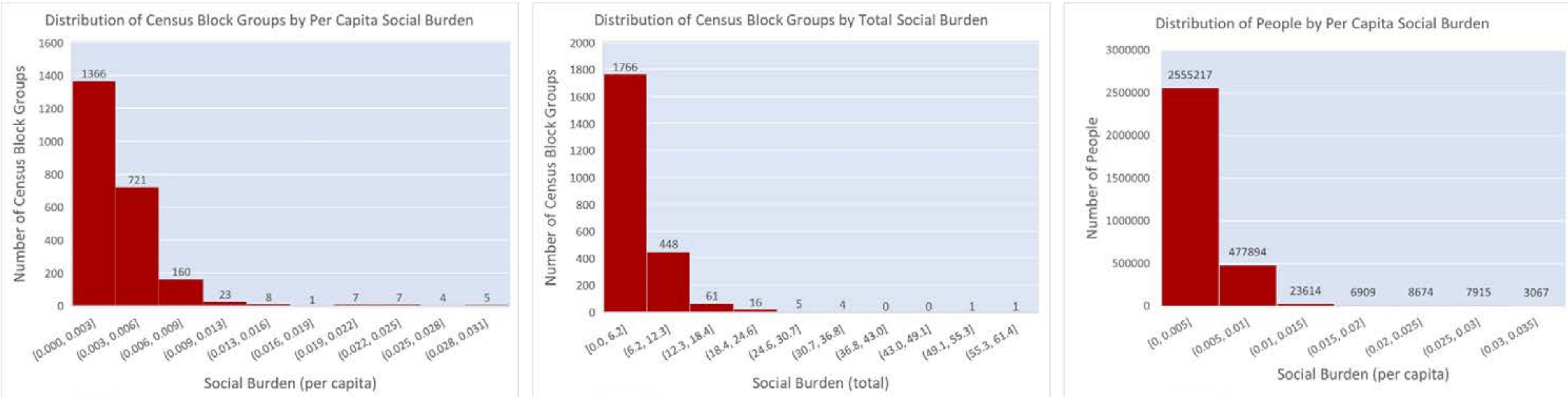

Figure 416. Distribution of census block groups and people by social burden levels

14.2.2.2 Social Burden Assessment for Threats

We performed a social burden analysis for each of the threat scenarios described previously: flooding, landslides, and earthquakes. Figure 418 shows the percent change in maximum social burden values for each scenario compared to the baseline. Social burden increases in all scenarios because infrastructure assets have been determined to be unavailable because threat impacts and the available critical services for residents are reduced. The results predict that landslides and earthquakes have less impact on social burden than do flooding and the combined threat scenarios. Referring to the infrastructure map in Figure 413 (page 563), this makes sense because the interior of the Commonwealth—which is more susceptible to landslides—has less infrastructure than the coastline, particularly San Juan, which is more impacted by flooding events. However, when looking at more isolated individual communities or municipalities, even a small change in service availability can have more significant negative consequences for residents. These areas will want to note any changes in infrastructure availability because of threat impacts and strive to mitigate loss of service.

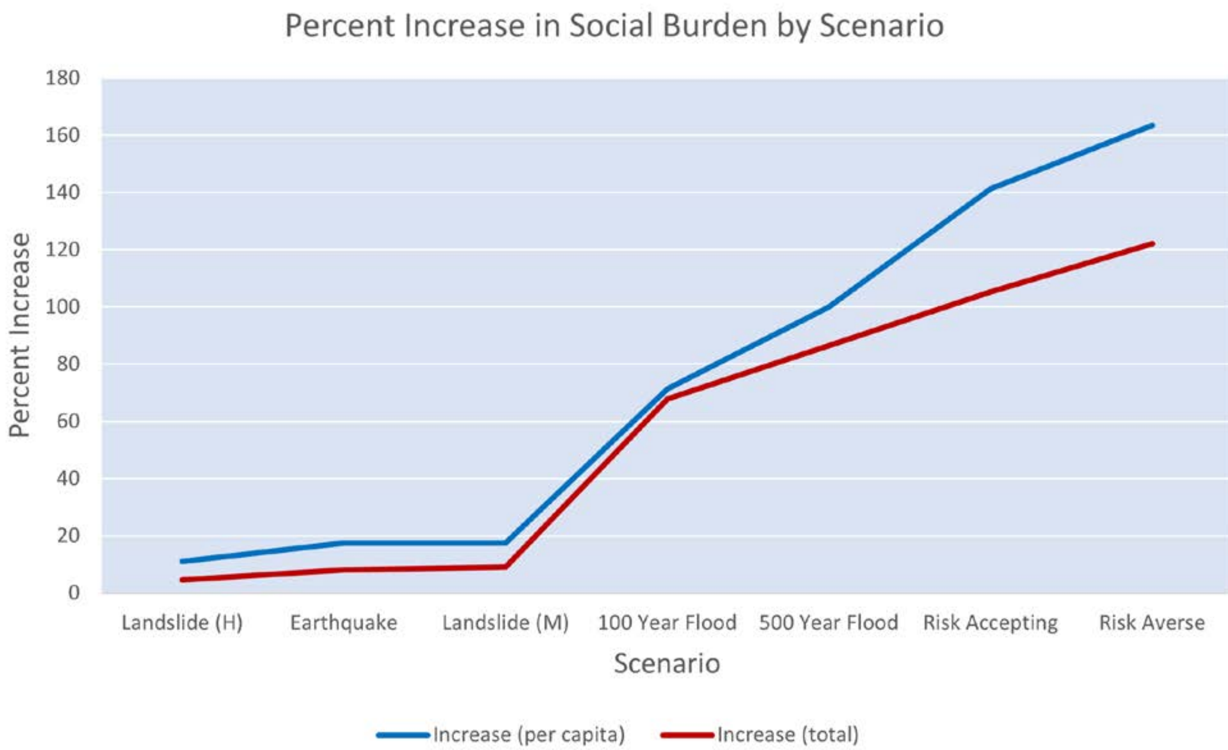

Figure 417. Percentage increase in maximum social burden for each threat scenario

The per capita maps for the baseline and each of these threat scenarios are shown in Figure 419. These maps confirm that flooding and combined threat scenarios have the most impact on social burden. This map comparison is provided here as a summary, but larger maps and maps weighted by population are available in the online data viewer.[201]

[201] http://www.pr100.gov/

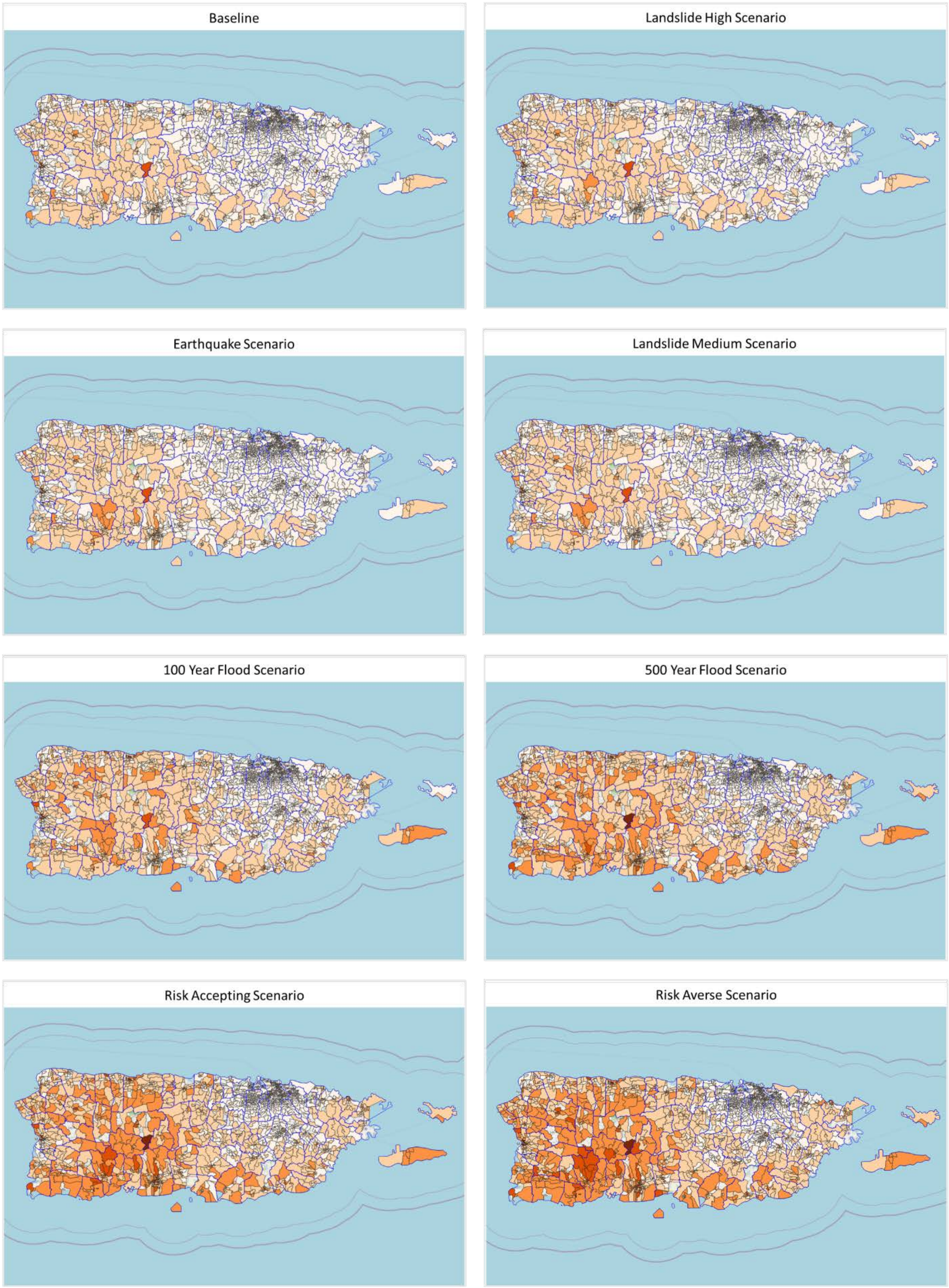

Figure 418. Per capita maps of social burden for the baseline and each threat scenario

Because the Risk Averse scenario—which is a combination of flooding, landslides, and earthquake threats—had the largest percentage increase in social burden compared to the baseline, the results for both per capita and total social burden are provided in Figure 420 and Figure 421 for further discussion. Compared to the baseline, social burden increases in the western half of the Commonwealth, particularly in the interior where the landslide risk is higher. We also see areas of increased burden in the southwestern area of the Commonwealth that has historically seen the most earthquake activity. Lastly, census block groups along the coast also experience an increase in social burden because of infrastructure unavailability from flooding projections.

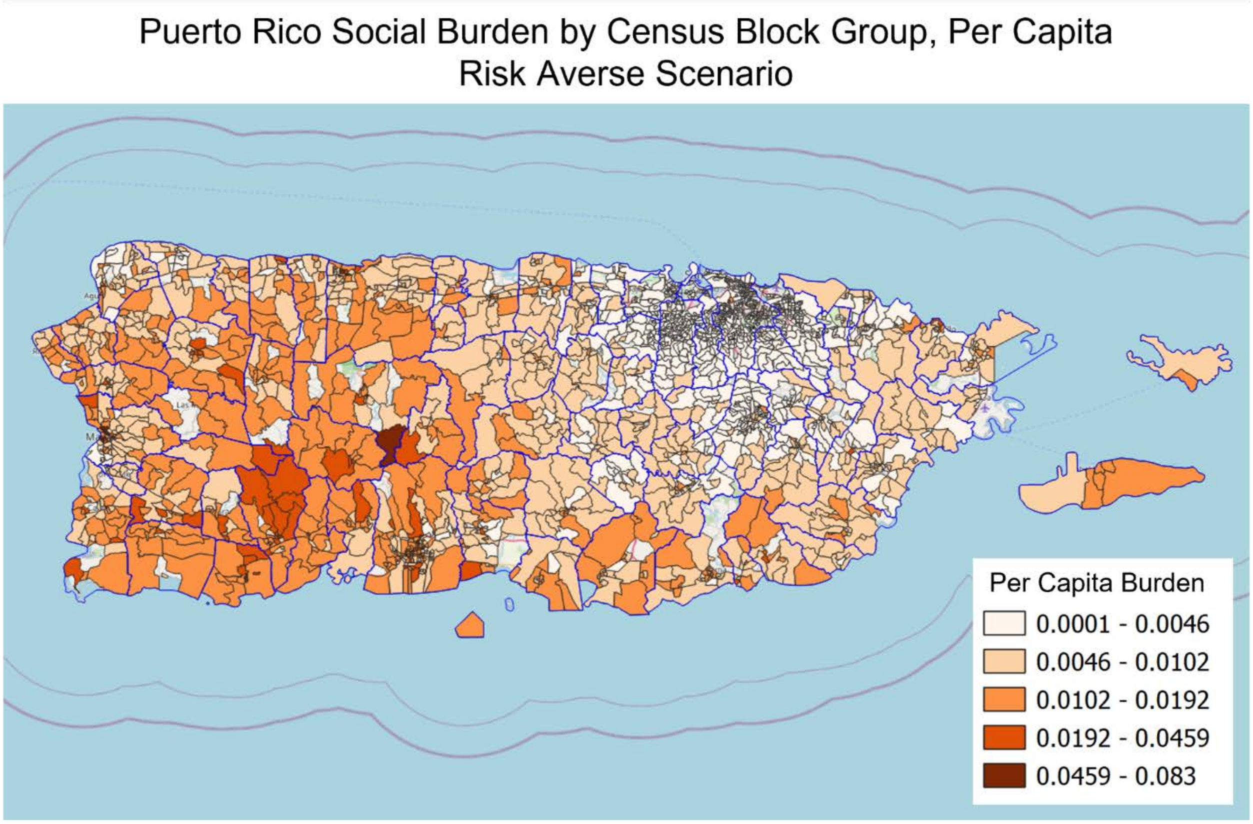

Figure 419. Per capita social burden by census block group for Risk Averse scenario

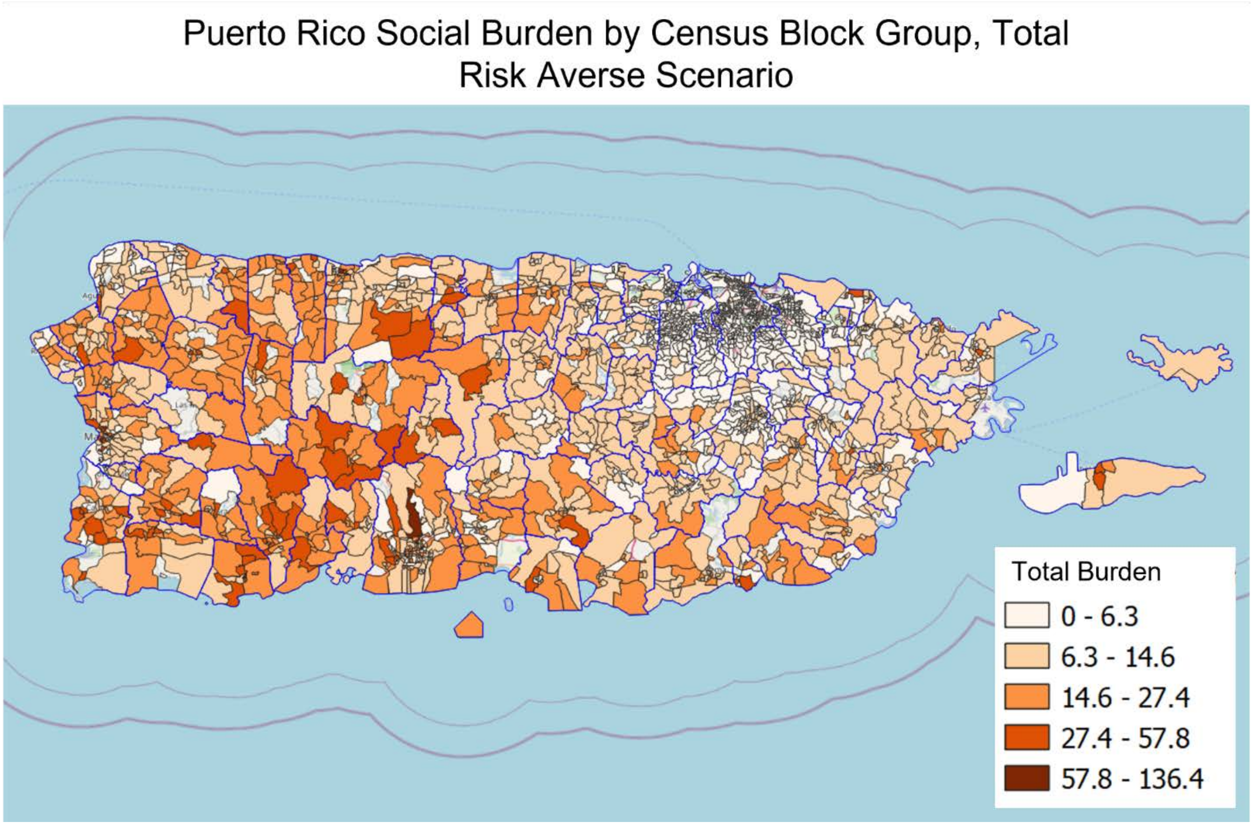

Figure 420. Total social burden by census block group for Risk Averse scenario

14.2.3 Energy Justice Implications

The social burden assessment may be used as guidance to identify areas for investment. The map-based results should be used in a comparative fashion to understand the level of social burden in one census block group or geographical area *relative* to another area. Following are the main ways this social burden assessment may be used:

- To identify areas that lack critical services, even during normal grid operations as were modeled in this assessment.
- To determine which critical services are provided at adequate levels and which services are not.
- To obtain a customized look at equity for Puerto Rico, based on infrastructure sectors and services that local stakeholders have prioritized.
- To understand how social burden changes as the availability of infrastructure assets changes. In this analysis, changes were caused by threat impacts, but future work should also look at changes due to full or partial grid outages.

Work has been done outside this project to understand how the levels of social burden change as prioritized restoration occurs. Future work could target an iterative investment planning approach where locations with long-duration outages are used to seed a ReNCAT optimization that then uses social burden as a metric to locate microgrids and other distributed energy resource (DER) investments at the distribution system level. Ensuring these areas have reliable power then informs utility-scale and transmission system investments and potentially changes the prioritization of lines for restoration.

Because both the baseline social burden analysis and the threat-informed social burden analyses for PR100 looked at social burden during normal grid operations, the results represent the best-case scenarios. In reality, threat scenarios would likely occur in conjunction with full or partial grid outages. Grid outages may also occur independently of threat scenarios or be caused by reliability failures, manufactured threats, or accidents. The next steps would be to look at service availability for specific outage scenarios, either historical or predicted, to understand the resulting change in social burden levels.

A practical approach to integrating the PR100 results into future work would be to identify census block groups with the highest social burden values during normal grid operations.

- These are the areas that already have low availability and access to critical services even in the best-case scenario when the grid is fully operational.
- Grid investments in these areas should ensure the limited services these residents have are kept online so as not to further increase their social burden.
- Particularly when multiple locations are being considered for resilience investments, a social burden evaluation can be used to compare options and determine which location would ultimately provide more benefit to local residents.

15 Uncertainties

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Section Summary

Uncertainty is inherent in any study depending on modeling and looking decades into the future, and it is amplified when the system being studied is changing rapidly and the data involved are complex. In the case of PR100, we added a layer of uncertainty when we employed a new modeling approach involving new methods and research tools. This section seeks to both provide detail on the major uncertainties that could significantly impact the results and conclusions of PR100 and collect the uncertainties from other sections to provide a broad picture of the uncertainty in PR100. Also, our scenario analysis attempted to bracket a set of uncertainties, but not all future possibilities are within those brackets.

15.1 Resource Uncertainties

Various uncertainties are associated with resource data generally. The solar resource, wind resource, and temperature resource data, as well as the climate change data are quite robust, as is the geospatial variation of these resources across Puerto Rico. The major uncertainties in PR100 involve the data on land exclusions in Puerto Rico and the ongoing evolution of the classification of land areas. For example, if non-energy development occurs when the electricity supply improves, some areas might become unavailable for utility-scale development and more rooftop area might become available. Also, Bolinger and Bolinger (2022) indicate that the density of PV production has increased in the CONUS and this effect of increasing power density, along with improvements to the efficiency of PV panels, might continue to make the technical potential higher for utility-scale PV. Similarly, for utility-scale wind power, the power density of wind could increase. Finally, though we explored and reported on several technologies (e.g., solar PV, land-based wind, offshore wind, marine, hydropower, and hydrogen), breakthrough technologies could generate more power from the same resource.

15.2 Load Uncertainties

The range from the Stress projection to the Mid case projection (Figure 422) captures uncertainty in future loads, and it bounds the future load trajectories facing Puerto Rico. However, if Puerto Rico sees a growing electric load into the future, this could be accompanied by changes not accounted for by PR100.

The load model that we used for the Mid case load scenario was based on the method developed by Siemens for the 2019 IRP (PREB 2020). That method implies four key data items will guide the future load: population, gross national product, manufacturing employment, and cooling degree days. The Financial Oversight and Management Board for Puerto Rico still projects population will continue to decline on the archipelago as will the gross domestic product (FOMB 2023a). However, if Puerto Rico transitions to a 100% renewable energy economy it is likely to experience significant economic growth. Additionally, this economic growth implies a more stable population, which would use more electricity. Finally, if the electricity supply is stable, industrial usage is likely to increase. A key variable here is the extent of tourism in Puerto Rico.

As the energy system is perceived to be more stable, tourism could increase in Puerto Rico, resulting in increased energy use (both in electricity and transportation energy use).

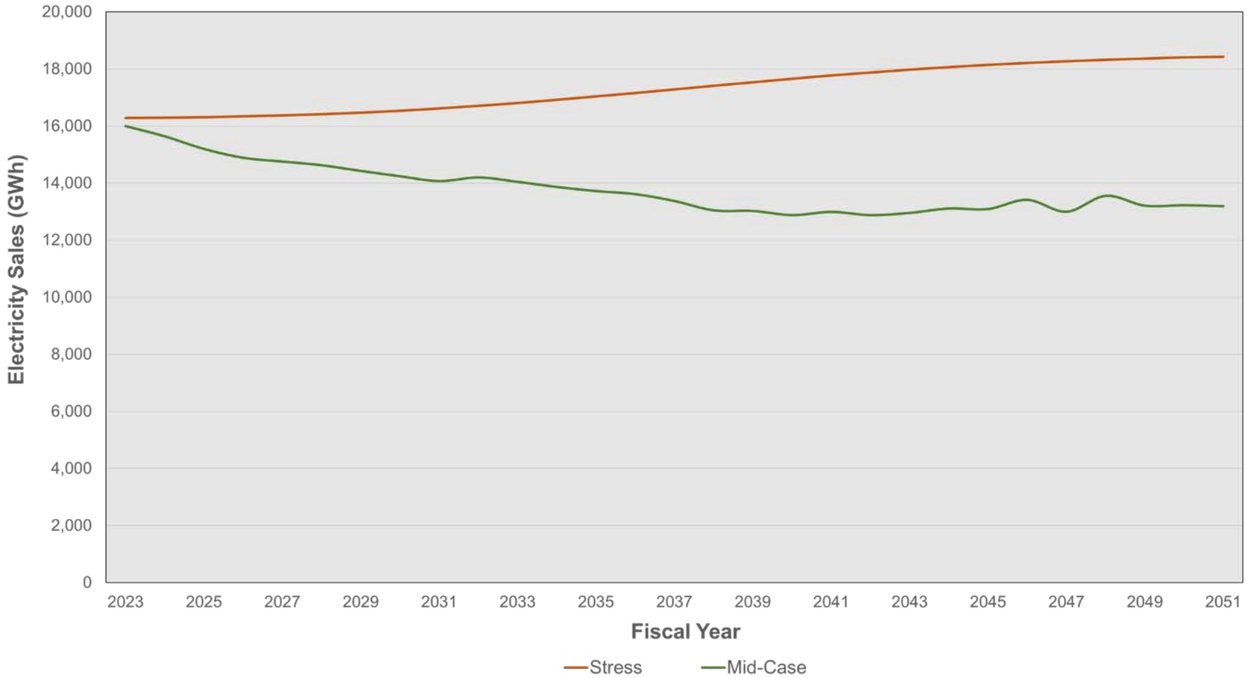

Figure 421. PR100 Electric load projections: Mid case and Stress variations for all of Puerto Rico (FY23–FY51)

Because of these uncertainties for the Mid case load projection and because we wanted to create a range of uncertainty, we developed the Stress load projection. We anticipate this increased load shape will likely capture the range of future electricity loads, though we cannot be certain.

The energy efficiency estimates that achieve the Act 17 goals imply a constant and growing level of efficiency across the economy that is unlikely in our experience and based on the bottom-up efficiency analysis created in PR100. The energy efficiency estimates completed in the study, while achieving notably lower savings than required by Act 17, are more achievable but still contain significant uncertainties that are due to the lack of underlying data on the current building and technology stock in Puerto Rico.

Lastly, the electric vehicle (EV) forecast (both light duty and medium-heavy duty) is based on current and historical transportation patterns in Puerto Rico and a modeling activity that examines several factors. However, the EV market and technology solutions are evolving rapidly and will likely continue to evolve throughout the study time frame. Therefore, significant uncertainty surrounds the anticipated rate and level of adoption by 2050. Rapid cost reductions in battery technology and automotive market changes could potentially double or significantly reduce the level of EV adoption. Also, if EVs become a reliable option for backup power during an outage, we anticipate the need for resiliency in Puerto Rico would drive additional adoption.

15.3 Scenario Uncertainties

Anytime an analysis involves future scenarios, the level of uncertainty grows throughout the timeline of the analysis. By 2050, various unexpected events likely will have occurred in the energy sector and tangential sectors that are unforeseen by the inputs to the PR100 modeling. For example, scenario analyses completed before 2008 would not have foreseen the surprising drop in PV prices in 2009–2011 nor the expansion of shale oil fracking and the resulting dramatic increase in U.S. oil and natural gas production. Similar drops in lithium-ion batteries from 2015 and continuing until now were broadly unanticipated before they began happening. Such implicit uncertainties reduce what can be confidently concluded about the future, but they do not reduce the value of scenarios to support current decisions and pathways.

In the case of renewable energy, incentives and supports to promote growth in the market can dramatically impact growth. Though this analysis included the expected impacts of the Inflation Reduction Act 2022, the analysis period extends past 2032 (the current end of the Act's incentives), and we currently model those incentives as ending in 2032. However, historically, U.S. incentives have often been anticipated to end but have then been extended. These incentives have served to grow the U.S. market for solar PV and wind in particular, and we anticipate an extension of the federal investment tax credit beyond 2032 would impact the costs of the electric system in Puerto Rico.

The main concern related to scenario uncertainty is whether our range of scenarios—which, in this case, result in a wide range of distributed PV and storage adoption, a range of load variations, and land usage—effectively captured the uncertainties we could identify at this point. We expect that the modeled levels of distributed PV and storage cover the possible range. Also, the load variations are likely to cover the range of possible loads into the future (particularly as we have both a declining load and increasing loads with most electric systems increasing by 1% or less per year). The land usage variations are impactful for agricultural lands, but we are confident most other filters (e.g., municipal areas, physical features, and park lands) are unlikely to change notably during the next few decades.

Lastly, the largest uncertainty of our scenario results is anticipated to be regulatory. The current modeling across all scenarios assumes the renewable portfolio standard (RPS) requirements in Act 17 are enforced. This includes reaching 40% renewable energy generation fraction by 2025 (and 60% by 2040 and 100% by 2050) as well as achieving 30% energy efficiency of end uses by 2040. Additionally, the retirement of existing plants is also prescribed by Act 17. Though the adoption of rooftop PV is modeled based on the detailed consumer behavior and typical S-curve adoption techniques in the Distributed Generation Market Demand Model (dGen) (Section 7 page 186), the results of the utility-scale capacity expansion modeling detailed in Section 8 (page 209) show a significant increase in renewable generation deployment to achieve these RPS targets at specific years. However, a prior RPS point of 20% renewables by 2022 established in Act 82-2010 (Puerto Rico Legislative Assembly 2010) was not met, and that resulted in no penalties or payments. In this report, we seek to explain what is needed to achieve the targets under the law but if these aggressive targets were not reached, we would anticipate a future restructuring of the RPS to provide updated guidance to market participants. Any changes to Act 17, including different dates for renewable energy penetration targets such as those proposed by

PREB (PREB 2023a), the energy efficiency goals, or retirements of existing plants, would significantly impact the scenario construction as well as the scenario results.

15.4 Reliability Uncertainty

Data uncertainty about the existing grid also creates uncertainty, but we received extensive power grid information from LUMA and PREPA. The uncertainties about the performance of existing plants and how they can be operated at their age are considerable and will grow if these plants are not retired as planned in Act 17.

The other uncertainty we sought to capture is resource (solar and wind) forecast error. *If* that forecast error is zero, significantly less generation capacity would be needed. However, the hourly and daily uncertainty implies a need for hundreds of additional megawatts of investment to maintain an appropriate level of reliability.

15.5 Technology Uncertainty

A range of technology uncertainties could significantly shift the specific scenario results as well as the level of impact of achieving the Act 17 targets. These uncertainties can involve the future costs of technology that are anticipated to be deployed but also introduce emerging technologies. In fact, many scenario analyses from NREL[202] and elsewhere often focus on the uncertainty of future cost trajectories in order to examine how those cost variations impact adoption.

15.5.1 Cost Uncertainty

Technology costs are discussed several times in this report, from the cost of rooftop PV and batteries to technology costs of utility-scale technologies. These costs were adjusted to be reflective of the current Puerto Rico market, and the technology costs are anticipated to follow U.S. state trends into the future. Of the several technologies deployed in the scenarios, the technologies with the greatest future cost uncertainty include battery storage (particularly 10+ hours of duration), rooftop PV systems, and offshore wind.

One component of the system costs is the financing costs. These costs in Puerto Rico are currently quite high due to the PREPA and Puerto Rico bankruptcies. A bankrupt buyer of electricity is a higher risk and therefore the lenders providing financing for the plant construction charge a greater interest rate on the loan for the project. In 2022, the multiplier of system costs from the CONUS costs to Puerto Rico-specific costs is 2.2. We anticipate this increased cost for financing Puerto Rico projects will decline after the bankruptcy is resolved and after successful plants are constructed, but that reduction is uncertain.

15.5.2 Emerging Technologies

There is a possibility of new technologies emerging as cost-effective options to impact the electric sector in Puerto Rico. Examples over the last few decades of this happening are cost-effective PV panels and lithium-ion batteries. Other technologies have achieved cost effectiveness but are not widely deployed in Puerto Rico in part due to additional development related challenges, such as small-scale hydropower, distributed wind, and offshore wind. All

[202] "Standard Scenarios," NREL, https://www.nrel.gov/analysis/standard-scenarios.html.

these technologies, while existing prior to PR100, have come down considerably in cost, resulting in accelerated growth and availability as sustainable options in the electric sector.

Several technologies that could become significant in the future of Puerto Rico's energy system but are unknown today. These include technologies, discussed in the following subsections, which are either broadly considered to be emerging or are of specific interest to Puerto Rico stakeholders.

15.5.2.1 Distributed Wind

Distributed wind turbines are distributed energy resources connected at the distribution level of an electric system, or in off-grid applications, to serve specific or local loads.[203] Distributed wind installations can range in size from small turbines (10's of kW), installed off of the grid to power remote homes or farms, to several utility-scale turbines (~1 MW+) connected on the distribution grid at a university campus, a manufacturing facility, or by the local utility (Orrell et al. 2023). Distributed turbines can be installed independently from the grid, as part of microgrids, behind a utility meter, or directly to the distribution energy system (Reilly et al. 2021). From 2003 through 2022, more than 90,000 wind turbines totaling 1,104 MW in capacity were deployed in distributed applications across all 50 states, the District of Columbia, Puerto Rico, the U.S. Virgin Islands, the Northern Mariana Islands, Guam. Puerto Rico was reported to have over 800 kW of distributed wind capacity installed at the end of 2022 (Orrell et al. 2023), indicating that although the deployed market is small, small-scale wind energy has been successfully deployed in Puerto Rico.

The costs of energy from distributed wind systems depend on the local wind resource, the size of the wind turbine being deployed, and local deployment conditions, and costs are generally higher than those of typical utility-scale land-based wind farms but are on par with the costs of commercial and residential PV.[204] Given the level of market development in Puerto Rico, these costs may underestimate actual project and operational costs. As an additional benefit, distributed-scale wind has a small operational footprint, allowing deployment in space-constrained areas and can increase the local contribution of renewable energy if all available areas of solar development have been developed. Because wind resource typically has different daily and seasonal profiles than solar, producing power aligned with the major evening peaks, hybrid wind and solar systems have the potential to lower the battery capacity needed by energy systems that are either connected to the grid in behind-the-meter or microgrid applications (Clark et al. 2022), leading to improved energy resilience. Wind turbines also provide different power characteristics than inverter based solar technologies, providing more flexibility to the grid. Lastly, the size of small-scale distributed wind systems could provide opportunities for Puerto Rico based manufacturing.

Given developing market potential in the United States (McCabe et al. 2022) and globally, including in extreme climates such as northern Alaska and the Caribbean, distributed wind technologies are likely applicable in many areas of Puerto Rico as indicated by the resource potential of wind power as shown in Figure 55 (Section 4.2, page 101). Many turbines are designed for exceptionally high winds and can be lowered to the ground before a major storm,

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[203] "Distributed Wind," DOE, https://www.energy.gov/eere/wind/distributed-wind.
[204] "Annual Technology Baseline: 2023 Electricity ATB Technologies and Data Review," NREL, https://atb.nrel.gov/electricity/2023/index.

but care would be needed to identify turbine models that were appropriate for Puerto Rico, as some vendor technologies would not be. PR100 did not incorporate distributed wind because of a lack of assessment data, but this technology should be considered for ongoing work given its synergies with distributed solar energy and storage systems.

The lack of a developed distributed wind market drives up costs and is a barrier to near-term deployment in Puerto Rico; however, given the similarities in size, scale, and complexity, distributed wind could provide a significant additional resource using the same financing, development mechanisms, and workforce as rooftop PV and battery storage.

15.5.2.2 Marine Energy

As indicated in Section 4.4 (page 114), a marine power assessment for Puerto Rico is in process that includes wave power, undersea current and tidal resources. With the significant number of marine resources in Puerto Rico, marine energy definitely has the possibility of becoming a viable alternative before 2050. Significant research and development investments are being made in various marine technologies with research happening at the DOE national laboratories[205] and elsewhere. However, these technologies would need to be proven able to survive a hurricane without damage, and it will take several years to prove to make this technology a bankable option for installation in Puerto Rico.

15.5.2.3 Hydropower and Pumped Storage Hydropower

As with marine energy, the resources for hydropower and pumped storage hydropower have been studied for Puerto Rico. Additionally, there is a history of hydropower in Puerto Rico, with over 100 MW of hydropower having been installed (of which roughly 10 MW is currently operational). Particularly with the growth of solar and wind in the 50 U.S. states, the need for pumped storage hydropower is anticipated to grow particularly for longer-duration storage, which is more expensive for lithium-ion batteries to provide. However, these technologies would likely need to be deployed on existing reservoirs and waterbodies in Puerto Rico, and they would need to be managed along with the other uses of the reservoirs. Finally, our cost-optimal utility-scale build-outs across PR100 scenarios did not find hydropower[206] to be cost-effective in Puerto Rico. Finally, ongoing changes to precipitation from climate change (See Section 13, page 507) could create future uncertainty in the resource. This effect is occurring in the western United States, where more variable annual rainfall and drought have led to operational issues with existing hydropower and pumped storage hydropower resources.

15.6 Other Key Uncertainties

15.6.1 Ocean Thermal Energy Conversion

Ocean thermal energy conversion (OTEC) has been a technology considered for island and coastal communities for many decades. Broadly, OTEC uses the temperature difference between very deep ocean water and surface water to generate renewable energy.[207] This technology has potential in areas where this change in temperature is greater than 20° C. In theory, this

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[205] "Marine Energy Research," NREL, https://www.nrel.gov/water/marine-energy.html
[206] We did not model pumped storage hydropower in PR100.
[207] "Ocean Therman Energy Conversion," National Oceanic and Atmospheric Administration. https://coast.noaa.gov/czm/thermalenergy/

temperature difference can drive a thermodynamic cycle that can drive a turbine to generate electricity. This technology is of specific interest to Puerto Rico stakeholders who have had several OTEC projects proposed by several firms over the years. We included OTEC as a modeling option to be considered based on some prior cost modeling of a plant that was proposed. Additionally, DOE has a long history of studying OTEC in Hawaii and elsewhere. In fact, a pilot OTEC plant was constructed in Hawaii; however, although the pipes to the ocean depths are still present in Hawaii, they no longer generate electricity after the pilot period ended. Nowhere are OTEC systems being commercially deployed, and anecdotal experiences indicate the temperature difference between the ocean surface and bottom is typically insufficient to cost-effectively drive a power cycle because of inherent losses and inefficiencies in the system. However, technology breakthroughs or other value streams from the OTEC system (such as mineral extraction from the water) could eventually make OTEC a viable technology solution. As with marine technologies, any system would also need to be hardened to survive a hurricane. Based on what we know currently, we believe the possibility of this technology entering the market significantly is low.

15.6.2 Long-Duration Storage

In the PR100 scenario results, 4-hr to 10-hr battery storage is commonly included. It is anticipated that 4-hr storage needs will be dominated by low-cost lithium-ion technology for the foreseeable future (Blair et al. 2022), and 10-hr storage falls under the definition of long-duration storage. Because lithium-ion battery costs scale based on duration, a 10-hr lithium-ion battery is more costly and other technologies could be viable competitors at this duration. The competitors (e.g., flow batteries, iron-air batteries, compressed air, liquid air, and pumped thermal storage) are all investing heavily to create viable products in this long-duration space—including 10 hours and beyond. If these technologies achieve their cost goals and commercial viability (i.e., become even cheaper than 10-hr lithium-ion batteries), even storage duration of longer than 10 hours might be deployed in Puerto Rico. This would be an improvement to system reliability and reduce the overall cost of the grid system.

15.6.3 Undersea Cables

Another area of uncertainty for the future energy system is the often-discussed power cable linkage to the 50 U.S. states. Prior discussions included a power linkage to the U.S. Virgin Islands and the Dominican Republic. Most recently, a developer proposed a power cable to the southeast part of the United States (from South Carolina) capable of transmitting 2 GW of power continuously.[208] As typical loads in Puerto Rico are 3 GW, this power cable would provide a significant portion of that power. Power cables could bring greater power stability but would be a large single point of failure for Puerto Rico.

This PR100 study did not model power cables as an option, but construction of such a project would dramatically change the makeup and cost structure of the electric system and could reduce the need for new generation plants in Puerto Rico. However, such power cables would not

[208] "Next Big Idea In Electricity: Subsea Cable From The Mainland To Puerto Rico," *Forbes*, January 24, 2023, by Llewellyn King, https://www.forbes.com/sites/llewellynking/2023/01/24/next-big-idea-in-electricity-subsea-cable-from-the-mainland-to-puerto-rico/?sh=7488dfab12bc.

necessarily provide greater resilience at the building level and the transmission grid would need to be resilient to transmit the power from the cable to customers across Puerto Rico.

15.6.4 Distribution System Modeling Uncertainty

Distribution system modeling in PR100 focused on 20 representative feeders due to limitations on data models available for more feeders and analysis bandwidth. While these feeders are expected to capture typical trends, there are more than 1,000 feeders in Puerto Rico and there will be variations across these feeders, including extreme examples that do not follow the trends captured in PR100. This variation within the distribution grid is a key source of uncertainty.

15.7 Regulatory Uncertainty

Our modeling across all scenarios assumes the RPS requirements in Act 17 are enforced. This includes reaching 40% renewable energy generation fraction by 2025 (and 60% by 2040 and 100% by 2050) as well as achieving 30% energy efficiency of end uses by 2040. Achieving these RPS requirements is highly uncertain and is likely the largest potential uncertainty pertaining to the results of our capacity expansion modeling.

Updates to the RPS requirements are likely to occur over the next year as the new integrated resource plan from LUMA is submitted to PREB. PREB has recently moved forward with establishing a year-by-year requirement for the renewable fraction, but that requirement still indicates a 40% annual renewable fraction in 2025, which PR100 results indicate would be difficult to meet.

15.8 Additional Fossil Fuel Generation Investment

The U.S. Army Corp of Engineers is leading an effort to install temporary generation units in Puerto Rico close to existing power plants.[209] These temporary units, which could be 300–700 MW, are intended to improve reliability and as allow existing plants to go offline for longer periods of repair. The uncertainty here lies in how long and when these units would be online and if, potentially, they end up staying in Puerto Rico and assisting with the shortfall in capacity currently being experienced. These additional generation units' capacities were not included in PR100 modeling because they are intended to temporarily offset other capacity that was included.

15.9 Additional Funds Provided to the Energy System

As with the existing Federal Emergency Management Agency (FEMA) funds available for reconstruction and recovery[210] and new Congressional funds to support rooftop PV and storage systems for low- and medium-income communities through the Puerto Rico Energy Resilience Fund administered by DOE's Grid Deployment Office (GDO),[211] there is the possibility of additional federal funds being committed to achieving a reliable and renewable grid in Puerto Rico. DOE's Loan Programs Office provides loans to projects and programs in Puerto

[209] "Business With Us / Contracting / Contracting in Puerto Rico," US Army Corps of Engineers. https://www.usace.army.mil/Business-With-Us/Contracting/Contracting-in-Puerto-Rico/.
[210] "FEMA Accelerated Awards Strategy (FAASt) Projects Execution," Central Office for Recovery, Reconstruction, and Resiliency. https://recovery.pr.gov/en/road-to-recovery/pa-faast/map
[211] "Puerto Rico Energy Resilience Fund, DOE GDO. https://www.energy.gov/gdo/puerto-rico-energy-resilience-fund

Rico,[212],[213] and it may provide financing to projects including some of the utility-scale projects. Future hurricanes could result in the obligation of additional federal funds as has been done before. Philanthropic organizations could also work to provide additional sources of funding, as well as the donation of PV systems and storage systems. A donation of capital (or cheap capital with low interest rates) could mitigate the cost of moving to a reliable, renewable system. Invested differently, additional funds could increase distributed PV and storage above the levels anticipated in Scenario 1 of PR100.

[212] "LPO Offers First Conditional Commitment for a Virtual Power Plant to Sunnova's Project Hestia, Including Loans for Puerto Rican Homeowners for Solar Installations," April 26, 2023, DOE LPO. https://www.energy.gov/lpo/articles/lpo-offers-first-conditional-commitment-virtual-power-plant-sunnovas-project-hestia-0

[213] "Notice to Applicants on LPO Determination of Eligibility for Puerto Rico Projects Applying Under the Energy Infrastructure Reinvestment (EIR) Program," July 21, 2023, DOE LPO. https://www.energy.gov/lpo/articles/notice-applicants-lpo-determination-eligibility-puerto-rico-projects-applying-under

16 Future Work

Section Summary

This section examines a variety of potential future research and analysis activities related to the results of PR100. These activities would significantly extend and refine the results of this analysis as well as, relevant to the Uncertainties section (Section 15, page 574), address uncertainties inherent in the study. These actions could be undertaken by the six national laboratories involved in PR100 and, importantly, by other researchers and analysts using the data, models and capabilities developed through PR100. These possible activities are grouped into key areas below aligned with findings in PR100.

16.1 Electric Load Analysis

- As we have done in PR100, any future electric load analysis based on PR100 should incorporate new Financial Oversight and Management Board for Puerto Rico forecasts as well as other inputs to the end-use load projections (e.g., population, gross national product, manufacturing employment, and cooling degree days).
- The PR100 project team understands from communication with PREB and LUMA that the ongoing Integrated Resource Plan process is using an updated end-use load projection methodology. Future work should evaluate and potentially adopt this new methodology for updates or modifications to PR100 scenario analysis. The future loads are a key driver of all results and we have bracketed possible outcomes with a Mid case and Stress load scenario; however, refinements would be beneficial.
- Future load analysis could use end-use load data currently collected by University of Puerto Rico at Mayagüez (UPRM), Mayagüez, the Puerto Rico Department of Housing, and others to refine hourly profiles of end-use loads, including sector disaggregated data (i.e., residential, commercial, and industrial).
- LUMA's ongoing baseline and potential study for energy efficiency will provide critical data to conduct a more refined PR100 bottom-up energy efficiency analysis. An analysis based on the data from the baseline and potential study could generate a separate specific set of recommendations for energy efficiency program development and deployment in Puerto Rico.
- Investing further in collecting sample building data and hourly load data specific to Puerto Rico could reduce assumptions in the hourly energy efficiency projections, whether they are based on the Act 17 goals or a bottom-up estimate and allow for deeper examination of energy efficiency programs and projects.
- Future analysis should also update the electric vehicle (EV) adoption projections because this area (EV adoption, including for light-duty, medium-duty, and heavy-duty vehicles) is evolving very rapidly across the country and within months to a few years the inputs to the EV analysis and related information might have changed significantly.
- Additional future sources of electric load could be considered for further analysis, such as air or maritime transport electrification and shore power for ships docked at ports (as well as other port improvements and development).

16.2 Distributed Solar Photovoltaics (PV) and Storage Adoption Modeling

- The range of rooftop scenarios could be significantly improved and extended, including by:
  - Running a separate study on the *value* of resiliency to calculate an improved input to reflect the value of backup power in Puerto Rico. Within that study, review UPRM work and other sources on this topic. As part of this study, run a range of scenarios within the dGen model to examine the sensitivities of distributed PV and storage adoption to the value of backup power.
  - Creating a set of compensation scenarios that better reflect potential alternatives to net metering after 2030 to support future decisions by PREB and Puerto Rico stakeholders.
  - Relatedly, creating a set of time-of-use scenarios for compensating customer generation, specifically incentivizing charging and discharging of customer batteries in support of local (distribution) and global (transmission) grid needs.
  - Creating a set of scenarios for distributed PV and storage adoption with a larger range of future retail rates coming from the downstream rates analysis to better estimate the uncertainty of potential economic impacts in Puerto Rico.
  - Examining industrial and commercial loads in greater detail. This could also be significant, as many of these loads are also currently supported by diesel backup generators and estimating the potentially significant load growth of shifting that demand back to the grid once the grid is more reliable.
- Additional capability to examine the impact of compensation for customer batteries being grid-interactive could be built out, including through coordinated schemes such as virtual power plants. Grid-interactive operation is nontrivial as customer batteries broadly have control, availability, and degradation implications.
- dGen could be run at feeder-level granularity. This would dramatically increase the number of regional locations (78– 1,000) but would allow for significant alignment improvement with distribution grid analysis.
- The modeling of multifamily buildings could be enabled by using geospatial data to incorporate space surrounding the building (parking lots) with an added cost for building solar-covered car parks at those buildings. Currently, it is not clear that local resilience in dense areas with significant multifamily structures is presented appropriately.
- Adjust storage adoption values based on trends in Puerto Rico and also based on compensation schemes such as time of use.
- As time-of-use rates are adopted and other temporal changes are made to load consumption such as EV adoption, bulk system temporal load analysis must be updated.

16.3 General Scenario Definition

In this report, the scenarios and variations around them express a range of future pathways. In reality, many scenarios could be run to provide data and relevant outputs that are not meant to reflect possible pathways but rather address questions from stakeholders about the future as Puerto Rico works towards a reliable and renewable electric grid in 2050. Some ideas for an expansion of the existing scenarios that provide additional information and insights to inform decisions and allow for greater fidelity in future analyses include:

- Expand scenarios to include baseline scenarios in which various current laws are not enforced to examine the impact of those laws (such as Act 17). These results would provide a basis of comparison and help calculate the incremental cost of various requirements.
- Introduce the ability and run relevant scenarios to economically (the model decides) retire utility-owned fossil fuel-powered generating resources as opposed to the legislated retirements currently modeled.
- As described in Section 1.2 for the Distributed Generation Market Demand Model (dGen), incorporate downstream implementation of a range of compensation scenarios and a range of retail rates as part of a set of overall scenarios.
- Include a <100% annual average renewable scenario with reliability to effectively examine the cost of achieving different points on the RPS but also the potentially large cost to go from a high level of annual renewable generation (~85%) to 100%, holding all other factors constant.
- Assess the ability for customer resources as prosumers to provide grid services potentially less expensively via demand response and/or virtual power plant programs (and the utility-side cost of those programs) than traditional approaches that rely on utility-scale generation resources.
- There is significant interest in Puerto Rico in varying levels of electrical islanding, from individual buildings to mini-grids and microgrids. Evaluate utility cost implications associated with different grid configurations (e.g., existing grid versus mini-grids versus microgrids).
- A variety of both nascent technologies (including distributed wind) and new system ideas (such as an undersea cable) are uncertainties that could be explored further with scenario modeling.

16.4 Capital Investment for Utility-Scale Capacity

- The Engage model continues to grow and expand in terms of capabilities. A near-term enhancement will better model the capacity that can be "counted on" (capacity credit) within the model. This and other enhancements could be used to run Engage for Puerto Rico in the future to see how the results change, if at all, and specifically to improve alignment with the PRAS model currently used to assess resource adequacy.
- Cost inputs to the capacity expansion effort are all adjusted for the Tranche 1 proposals. Those proposals are unlikely to be what the projects will eventually cost, and it would be very interesting to do additional capacity expansion analysis with updated cost inputs (this is true for distributed technologies as well).
- Finally, many capacity expansion analyses model a variety of future costs trajectories in order to examine the system sensitivity to uncertainties in future costs. That was not done in this analysis but would inform the impact of uncertainty around future costs. Sometimes, the impact of cost uncertainty can be dramatic and unexpected. Particularly, running more sensitivities to fuel costs, battery costs, and other more uncertain technologies could give the stakeholders of Puerto Rico a richer data set.

16.5 Grid Operations Including Production Cost and Resource Adequacy

- Due to the small geographic region of Puerto Rico, a principal concern for the Puerto Rico grid is managing forecast errors and variability of energy resources and demand. PR100 was able to create consistent representations of day-ahead generation forecasts and hourly actuals for a single weather year. However, PR100 results suggest that both longer (e.g., multiday) and shorter (e.g., 4-hr ahead) than day-ahead scheduling is required to manage storage resources and maintain reliable service. Additionally, multiple weather year data would support more robust resource adequacy analysis. Additional work is required to produce multiple years of multiday forecast data and subhourly realization data for wind and solar resources. Additionally, demand forecasts and subhourly demand data, along with temporally consistent EV and energy efficiency demand projections is required to support analysis.
- PR100 results suggest that evolving ancillary service definitions and requirements is critical to maintaining reliable operations. The additional resource forecasts and demand data can inform improved ancillary service and reserve designs.
- Demand response poses a significant opportunity to address several operational challenges on Puerto Rico's grid. Additional work is required to explore opportunities for demand side management through a variety of different programs including real-time pricing, demand shedding, demand shifting, and distributed resource management with virtual power plants.
- As EV adoption increases in the future, there is an opportunity to provide grid services through managed charging. This is an area that requires additional exploration.
- Additional interconnection siting analysis and/or transmission network expansion analysis is required to support the PR100 future system buildouts. By carefully siting storage resources and interconnection locations for utility-scale renewable generation, many of the challenges encountered in the 38-kV transmission network in PR100 simulations could be mitigated.
- PR100 results highlight the opportunities to locate large amounts of utility-scale generation near the most energy demands. This result indicates a potential opportunity to enable multiple regional mini-grids in Puerto Rico to increase resilience. Additional analysis is required to evaluate the necessary adjustments to PR100 buildouts to support resource adequacy in each mini-grid, and to evaluate mini-grid operations during nominal and extreme conditions.
- The existing generation fleet is aging, but many legacy generators will continue to play a critical role in reliable system operations for several years. Proper maintenance scheduling is critical to provide opportunities for needed repairs and upkeep, and to avoid scheduling repairs during periods of critical need. With rapid growth of renewable generation in Puerto Rico, maintenance scheduling is evolving, and additional modeling is required to identify risk-minimizing generator maintenance schedules.

16.6 Bulk System Analysis

The following future analysis is derived from the bulk system power flow, stability, and resilience analysis:

- Perform exhaustive contingency analysis like in NERC TPL standards to determine grid upgrades to reach industry accepted levels of transmission and sub-transmission reliability particularly in the near term as the system expands to reach 40% of energy generated by renewables.

- In conjunction with 38-kV transmission expansion and generation and storage siting study, perform planning studies for additional voltage support equipment for transmission and sub-transmission while utilizing voltage support from all renewables and energy storage resources. These studies should include requirements for additional dynamic voltage control compensation equipment as well as fixed and switched capacitor and reactor equipment.
- Develop detailed grid code recommendations and studies for Puerto Rico's adoption of advanced inverter controls for the near term, for stable operation under 100% instantaneous inverter conditions (which could happen when the 40% renewable requirement of Act-17 is reached or earlier). Advanced inverter controls requirements should include: (1) requirements for grid-forming control in battery energy storage systems; (2) study possibility of requiring grid-forming capability from inverters in renewable generation; (3) research possibility of utilizing grid-forming functions of DER inverters while operating in grid-connected mode; (4) requirements for fast frequency response and voltage control requirements for all inverter-based resources; (5) requirements for black start controls in utility-scale BESS; (6) research and develop small projects for participation of solar generation in black start and system recovery; (7) revise voltage and frequency ride through requirements for both utility-scale and DER inverter-based resources; and (8) requirements for connection of utility-scale resources to the control center to participate on automatic generation control and voltage supervisory control functions.
- Research and develop small projects for solar renewable generation to participate in black start and system restoration on the following aspects: 1) coordination of solar generation with energy storage to assist in black start and restoration of transmission and sub-transmission systems, considering development of small projects in Puerto Rico; 2) for DER in grid-connected mode, develop strategies for operation and grid support modes to support black start and restoration processes, considering also small projects; 3) develop full system restoration strategies in stages including sub-island operation as part of the process to recover full grid after a hurricane event.
- Detailed analysis of grid strength and protection system upgrades, especially for the short term (40% renewables with 100% instantaneous inverters), to determine needs for synchronous condenser functionality from existing or new equipment. Particularly, the study should consider the ability of resources to contribute with fault current together with the ability of upgraded protection systems to tolerate systems with low grid strength. System stability should also be studied further in places in the system with reduction of system strength, considering grid-forming inverters and/or synchronous condensers as part of the possible solutions.
- Establish advanced stability modeling practices including model validation, verification of stability models of various resolutions: 1) high-fidelity models, such as those in electromagnetic simulations software, of the full system in Puerto Rico, 2) accurate phasor-based dynamic models, like the type of models currently used in Puerto Rico, for faster stability analysis. Additionally, recommend establishing practices to ensure accuracy in inverter models by working with inverter manufacturers to provide accurate models; require model validation and testing procedures during commissioning and periodic model revalidations after commissioning; establish model verification practices through event analysis from high-resolution measurements.

- Detailed cascading failure studies considering inverter controls and protection system performance under severe outages, evaluating possible improvements in inverter controls and protection settings to help the grid performance during cascading failures including during hurricanes.
- Perform detailed studies for prioritization of transmission and sub-transmission system upgrades and hardening for improved reliability as well as resilience for hurricane events, particularly for the short term as the system achieves 40% renewable target with significant portion of distributed solutions. Consider management and planning for failure of legacy infrastructure.
- Detailed studies to incorporate resilience evaluations in siting decisions of renewable generation and energy storage in the transmission and sub-transmission system. Siting evaluation studies should consider both the ability of the future system to recover from severe events as well as mitigation of grid failure due to events like hurricanes.
- Study grid impact and grid recovery for various future hurricane event scenarios derived from future climate conditions.
- Develop additional research to incorporate energy justice metrics, such as social burden, in transmission and sub-transmission upgrades decisions.
- Study current air conditioning load composition as well as collecting high-resolution system measurements, when available, to study fault induced delayed voltage recovery (FIDVR) events in Puerto Rico. The study should consider adoption of variable frequency drive air conditioners in Puerto Rico and evaluate if FIDVR effect would be mitigated in the future or it would be a concern, especially as FIDVR could cause further disconnections of DER.
- Develop monitoring and control algorithms to operate the system with high penetration of renewables including real-time reliability assessments that make use of real-time high-resolution grid measurement systems (phasor measurement units) and associated communication infrastructure to evaluate system reliability.

16.7 Distribution System Analysis

- Detailed analysis of grid upgrades needed to bring the system to “industry-acceptable” level. Analysis should investigate the best course of action for capacitors (remove, make manually switching, control, et cetera), the need to convert 4-kV feeders to higher voltage, and general system vulnerabilities (precarious lines, undersized transformers, et cetera).
- Deeper investigation into battery controls, specifically the optimal location and sizing to minimize cost while maintaining full hosting capacity to accommodate all predicted distributed generation.
- Demonstrate the value of advanced metering infrastructure in system monitoring and visibility, such as detecting local hosting capacity violations due to overvoltage or overloading at the service transformer-level.
- Consider protection system implications: model fuses, relays, and other protective equipment to understand the impacts as renewable energy penetrations increase and to verify that control actions to mitigate backfeeding, voltage, and line loading also mitigate protection system concerns.
- Further investigation into resilience opportunities such as forming microgrids during power outages. PR100 analysis showed this was possible, but did not explore the different control

schemes, switch locations, possibility to only power critical loads to extend functionality, et cetera.

16.8 Macroeconomic Analysis

- A workforce analysis that identifies the specific skill sets needed to meet the job requirements which will support the transition to high penetration levels of renewable energy, both at the distributed-scale and utility-scale, would be beneficial to augment the jobs assessment performed in PR100 which simply identified the number of workers needed.
- A supply chain and infrastructure analysis that identifies potential bottlenecks in the movement of goods into and around Puerto Rico that will support the transition to high penetration levels of renewable energy, both at the distributed scale and utility scale, is needed to identify where new construction or expansion of critical facilities will be most beneficial.

17 Implementation Roadmap

Authors: Cody Newlun[1], Matthew Lave[1], Richard Garrett[1], Olga Hart[1] with contributions from the entire PR100 project team

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Section Summary

This section is the PR100 Implementation Roadmap (Roadmap). In it, we identify implementation actions stakeholders can take to progress toward a more robust,[214] reliable, renewable, resilient, and equitable energy system for Puerto Rico. Actions are categorized temporally into immediate, near-, mid-, and long-term actions. These actions are based on the results of the analysis in PR100, observations we made about Puerto Rico's current energy system while performing the PR100 analysis, perspectives we collected via stakeholder engagement, and our knowledge of industry best practices. The considerations that motivated these actions are highlighted throughout the report and are aggregated and discussed in this section.

Key Findings

Key findings for this section include actions that stakeholders can take in the immediate, near, mid, and long term to transition the Puerto Rico power system from its current state to the target state. In this section summary are the high-level themes that categorize the actions for each time period. Specific actions, including a discussion about stakeholder roles, action areas, and rationale for actions, are detailed in Sections 17.3–17.6.

Immediate Actions (Section 17.2)

Immediate actions to position the system for the energy transition include:

- *Improve power system robustness* by increasing generation capacity and making urgent repairs.
- *Deploy new renewable resources and storage* via stakeholder-driven pathways.
- *Change customer compensation schemes* to incentivize temporal-based charging and discharging among stakeholders,

Near-Term Actions (Section 17.3)

In the near term, the system will transition from the current state to one in which renewables account for 40% of generation. The primary goal during this phase is to improve system performance to an industry-accepted level while targeting resilience. The near-term actions include:

- *Proactively plan and execute to meet renewable portfolio standard targets*, including installing multiple gigawatts of renewable resources and storage and rapidly designing and implementing energy efficiency to achieve Act 17 goals.
- *Update bulk power system and operation*: update operational strategies, establish requirements for grid-forming inverters, study and upgrade lower-voltage (38-kV) transmission network, plan for future renewable penetrations, and deploy storage.
- *Update the distribution system*: upgrade control schemes including voltage regulation, deploy storage at critical points, and prioritize upgrades on vulnerable feeders.

[214] In this section, the term "robust" refers to the state of repair of the electric system.

Mid-Term Actions (Section 17.4)

The primary goal in the mid term as the system goes from 40% to 60% renewables is for stakeholders to gain operating experience and be adaptive in system design. Actions that support the implementation include:

- *Continue aggressive deployments* of renewable resources, including significant amounts of storage.
- *Implement operation schemes needed under high penetrations* of renewables including advanced forecasting, operating reserves, and protection coordination schemes.
- *Examine impacts of redesigned retail rates* and distributed generation compensation schemes and modify as needed to achieve efficient system operation and support equitable solutions.

Long-Term Actions (Section 17.5)

In the long term, as the system approaches 100% renewables, the primary goals are to achieve effective deployment and efficiently operate the complex system. Uncertainty is especially significant during this phase, as it is in any study looking out several decades. Long-term actions are summarized as follows:

- *Deploy the renewable resources needed to achieve 100% penetration*, including implementing a broad range of storage technologies, such as long-duration storage, and dispatchable renewable resources.
- *Enact system upgrades and operational changes* to mitigate congestion issues from a high-renewables system with dispersed generation; enable black-start and recovery capabilities of all assets via grid-forming controls.
- *Leverage system interoperability* between loads such as increased electric vehicle adoption and variable generation using advanced forecasting, dynamic rates, and export compensation schemes.

Recurring Actions (Section 17.6)

In addition to near-, mid-, and long-term action items, we identified several recurring actions for stakeholders to take throughout the energy transition. Recurring actions include:

- *Improve and evolve planning processes*: Identify and pursue stakeholder-informed pathways for deploying new resources and storage, including considering land use and local resilience benefits. Further adapt processes to evolving threat landscape and coordinate with interdependent infrastructure systems.
- *Facilitate a stable, local workforce* to support installation, operation, and maintenance of the system across the entire planning horizon.

17.1 Introduction

17.1.1 Roadmap Objective and Development Process

The objective of the PR100 Implementation Roadmap (Roadmap) is to identify actionable pathways stakeholders can take to get from the current state to the target state, as outlined in Figure 423. The current state of the Puerto Rico energy system, as described throughout this section, is fragile and experiences frequent outages, and the system has experienced prolonged outages after extreme meteorological events. The target state is to achieve the goals laid out in Act 17: achieving 100% renewable energy penetration and 30% energy efficiency. Additional elements of the target state—which were informed by PR100 findings and stakeholder input—include grid upgrades, enhanced system reliability and resilience, energy justice, and economic development.

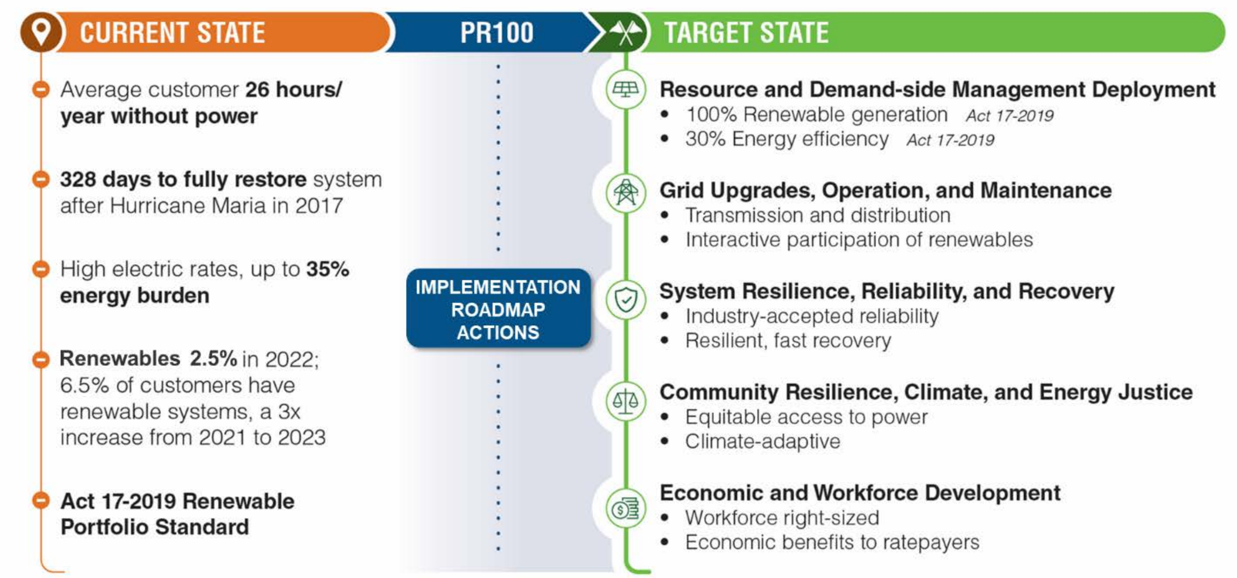


Figure 422. Current and target state of the Puerto Rico energy system

Sources: LUMA (2023d), COR3 (2019b), LEAD Tool[215]

The Roadmap is driven by findings from PR100 and stakeholder input. The technical results of PR100 were synthesized into temporal implementation actions needed to effectively achieve Puerto Rico's transition to 100% renewable energy. Figure 424 displays a conceptual diagram of how various actionable pathways can be followed to transition from the current state to the target state.

[215] "Low-Income Energy Affordability Data (LEAD) Tool," DOE, https://www.energy.gov/scep/slsc/lead-tool

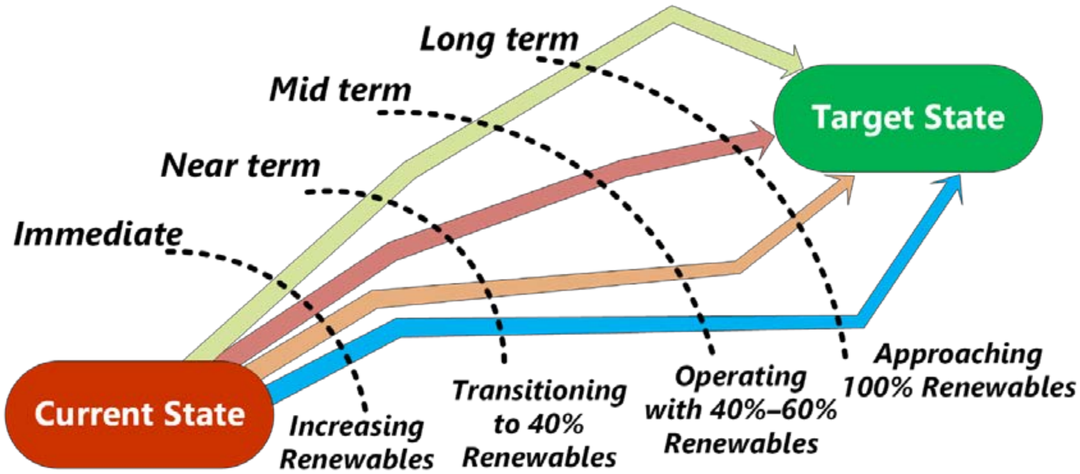


Figure 423. High-level diagram of an example of actionable pathways between current and target states with temporal characteristics (near term, mid term, and long term)

Creation of the Roadmap included several efforts to ensure it was well-informed and accurately reflected both PR100 key findings and stakeholder input. Throughout the roadmapping process, stakeholders were engaged to better understand implementation challenges in Puerto Rico. The PR100 technical results and key findings were synthesized into implementable actions, and those actions were mapped into near-, mid-, and long-term actions. Furthermore, the actions were set up to ensure actions were complementary across the different time frames.

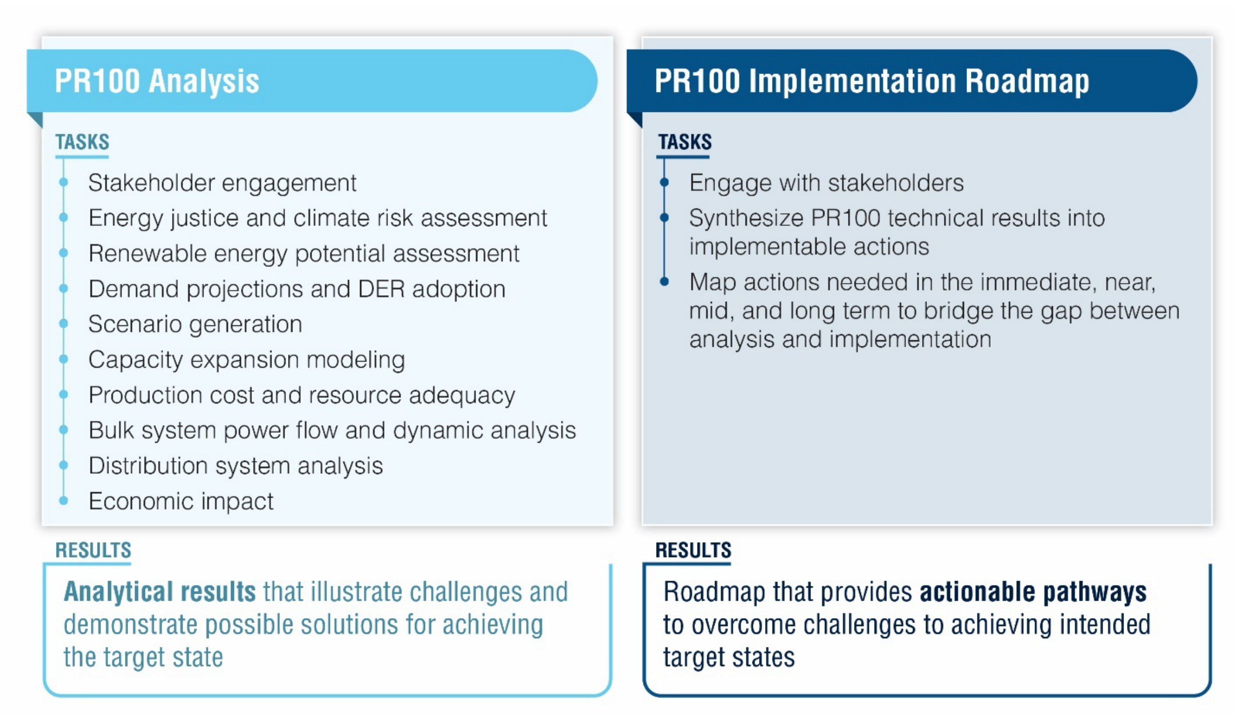


Figure 424. PR100 analyses informed the Roadmap by providing analytical results that were synthesized into actionable pathways

The methodology employed to craft the Roadmap was rooted in the technology roadmap literature. Technology roadmaps emerged from industry decades ago to identify and plan for strategic outcomes. Kerr and Phaal (2022) provided a concise literature review of roadmaps. They defined a roadmap as "the application of a temporal-spatial structured strategic lens" to create a roadmap, "a structured visual chronology of strategic intent." In other words, creating a roadmap involves the development of visual products that convey the time-dependence of activities required for a certain strategic outcome. For PR100, the strategic outcome considered was the transition of the Puerto Rico energy system to 100% renewable energy by 2050 according to Act 17.

Developing a roadmap is a highly collaborative, structured process to brainstorm, organize, and prioritize relevant information for the roadmap (J. V. Hillegas-Elting 2017). The process is not standardized and can be customized to suit the specific needs of an organization (James V Hillegas-Elting 2016; Kerr, Phaal, and David Probert 2011; DOE 2021a).

Energy transition roadmaps can be considered a subset of technology roadmaps to provide a plan for how to modify an existing energy system (J. V. Hillegas-Elting 2017). Energy transition roadmaps have been developed for several regions globally, including the U.S. Virgin Islands (NREL 2011), Central America (IRENA 2011), and the U.S. states of Hawaii and Maine (DOE 2021a). A theme of those roadmaps is the need to overcome challenges with aging, legacy electric power infrastructure by deploying renewable energy systems with a high degree of resilience. DOE's Energy Transitions Initiative (DOE 2021a) provides detailed instructions and resources for communities to plan their energy transition efforts.

Development of the Roadmap leveraged techniques from previous roadmap efforts to convey the study results and stakeholder perspectives in an actionable manner. Reporting mechanisms were developed to gather key takeaways from all PR100 tasks. The key takeaways were then aggregated and distilled into Roadmap actions. PR100 results involve significant variety in the timing of actions needed to transition from the current state through to the target state.

17.1.2 Role of the Implementation Roadmap

The Roadmap does not make policy recommendations or specific investment recommendations but instead suggests actions that can enable the energy transition to 100% renewables. The Roadmap does not prioritize any of the scenarios discussed in Section 6 (page 173), nor does it recommend a single "correct" or "optimal" pathway. Rather, as applicable, the Roadmap highlights commonalities across all scenarios to emphasize solutions that can confidently be implemented. The Roadmap does not replace mandated capital investment planning processes such as the Integrated Resource Plan (PREB 2020). Instead, it is intended to facilitate decision-making for stakeholders at all levels. The intended audience for the Roadmap includes Puerto Rico's utilities and grid operators, renewable energy developers, energy regulators, utility customers and community partners, and any other parties interested in Puerto Rico's energy transition. In this way, the Roadmap is intended to highlight actionable pathways to facilitate the energy transition in Puerto Rico and it is the stakeholders' responsibility to identify solutions to complete the necessary actions.

17.1.3 Main Goals and Temporal Structure of the Roadmap

The Roadmap organizes implementation actions into four temporal periods defined by increasing levels of renewable energy penetrations. These periods are consistent with the goals and timeline of Act 17, though periods are defined based on renewable energy penetrations, not specific calendar years, to ensure applicability of the Roadmap even if timelines change. Immediate actions are urgent actions needed to point the system in the right direction today so that it can meet electricity demand while integrating planned renewable generation, both distributed and utility-scale. Near term is the time between now and when the system reaches 40% renewable penetration. Mid term is defined as the time when the system increases renewables from 40% to 60% renewable penetration. Long term is the period leading up to, and at the end achieving, a system that is 100% renewable. These periods, and the main goals during each, are shown in Figure 426 and described in detail in this section.

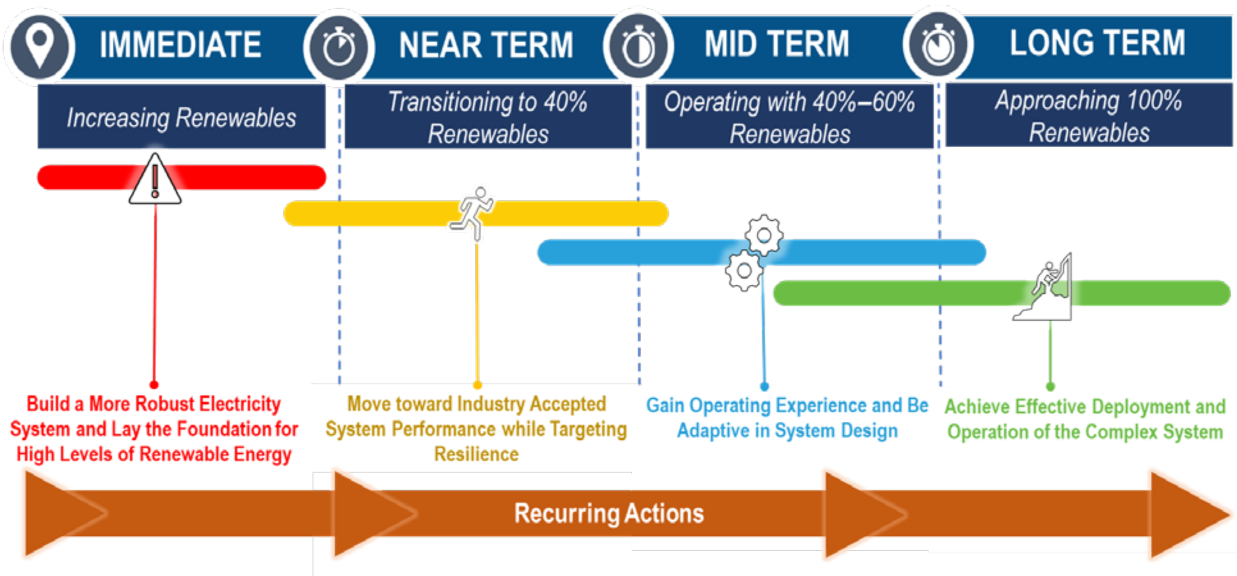


Figure 425. Main goals of the Roadmap

Immediate: Build a More Robust Electric System and Lay the Foundation for High Levels of Renewable Energy

As indicated from the results of PR100 across all scenarios considered, there is an immediate need to build a robust power system to lay the foundation for future high levels of renewable penetration.[216] Increasing robustness means enhancing the state of repair (e.g., fixing falling power poles) and increasing the speed of recovery on the system after outages. These immediate actions can begin today to point the system in the right direction to achieve the goals of future periods. If actions are taken right away, the power system will be better positioned to achieve near-term targets by having increased system robustness and enabling the integration of more renewable resources on the system.

[216] Throughout this section the term "robust" refers to the state of repair of the electric system.

Near Term: Move Toward Industry-Accepted System Performance while Targeting Resilience (Transitioning to 40% Renewables)

The Puerto Rico power system will require significant maintenance and upgrades to accommodate new renewable energy capacity and to improve the system toward acceptable performance. Acceptable performance can be defined as achieving industry-accepted reliability metrics and enhanced resilience to mitigate impacts during and after a threat or major disruption to service; however, these metrics must be agreed upon by the stakeholders of Puerto Rico and they might not align exactly with industry performance in the 50 U.S. states.

Mid Term: Gain Operating Experience and Be Adaptive in System Design (Operating With 40%–60% Renewables)

Small-scale deployments of emerging technology projects must be used to gain foundational knowledge and operating experience to facilitate the ongoing and increasing adoption of renewables. As technologies mature (e.g., long-duration storage, dispatchable renewable generation, or participation of storage and renewables in black start and restoration), changes in climate occur, consumer behavior changes, and community priorities shift, grid planners must effectively and efficiently adapt to the uncertainties inherent in such changes. Adaptation in the mid term is critical to ensure long-term benefits to the stakeholders of Puerto Rico.

Long Term: Achieve Effective Deployment and Operation of the Complex System (Approaching 100% Renewables)

As the power system approaches 100% renewable penetration, effective deployment and operation will be important to achieve the desired levels of reliability, resilience, cost-effectiveness, equity, and energy justice. Using lessons learned while gaining operating experience during the mid term, full-scale deployment can be achieved to support the final stages of the energy transition. The long term inherently includes significant uncertainties because it is far into the future, so it will be important for stakeholders to be adaptive and flexible as they execute into the long term, when some of the uncertainties will come into focus.

Recurring Actions: Continually Maintain the System and Improve Planning Processes

In addition to the immediate, near-, mid-, and long-term actions, the Roadmap identifies several recurring actions that stakeholders should consider throughout all periods of the energy transition. Many of the recurring actions are not technical findings of PR100 but are best practices identified through stakeholder engagement and energy justice analysis conducted as part of PR100.

17.1.4 Stakeholder Roles

For the Roadmap, the wide range of stakeholders involved in PR100 were grouped into four categories to highlight the roles of different stakeholder groups in the energy transition:

- *Utilities and Grid Operators* included transmission and distribution (T&D) operator, generation system operator, and distributed energy resources (DERs) aggregators.
- *Renewable Developers* included installers, trade organizations, and consultants.
- *Customers and Community Partners* included the individual customer, community organizations, community leaders, and local universities (who are involved with community support).

- *Energy Regulators* included the regulators, policymakers, and government agencies responsible for developing and enforcing energy policies and incentive programs.

The manner in which stakeholder roles may influence the Roadmap was considered in order to streamline discussions and help guide follow-on efforts to develop detailed implementation plans. Specifically, stakeholder groups may inform decisions, play a role in decision-making, and/or play a role in implementation. In addition to defining current and target states and identifying implementation actions and challenges, stakeholders' roles were also used to map actions to stakeholder groups in an effort to enhance the planning processes.

Stakeholder input informed nearly every aspect of PR100, including the development of the Roadmap. Periodic presentations of Roadmap updates were given at Advisory Group meetings throughout the project. Additionally, in October 2023, the Roadmap team hosted four in-person stakeholder meetings in San Juan, Puerto Rico. The purpose of these meetings was to solicit feedback on the draft topical Roadmap, including identifying implementation challenges and specifying actions that can be taken in the near term, mid term, and long term to reach the desired target state. Four separate meetings were held to collect input from different stakeholder groups: multisector stakeholders; residential and community groups; renewable developers; and utilities, operators, and government entities. Via both Advisory Group meetings and Roadmap-specific meetings, stakeholders' feedback and perspectives helped us develop the implementation actions presented in the Roadmap.

17.1.5 Roadmap Action Areas

PR100 provides in-depth analyses into a wide range of technical aspects related to grid planning. The significant number of findings across a wide array of technical, economic, and stakeholder engagement topics—many of which are interconnected and have crosscutting themes—could quickly become unwieldy. To help organize the findings, we developed five Roadmap action areas:

Resource and Demand-Side Management Deployment: the required resources—both distributed and utility-scale and demand-side management programs—that must be deployed to support the energy transition and compliance with Act 17. PR100 extensively studied the future resource mix of Puerto Rico via distributed generation forecasting and capacity expansion planning models, and the corresponding technical results were leveraged for roadmap development (Sections 4, 7, and 8).

Grid Upgrades, Operation, and Maintenance: the implementation considerations regarding the needed infrastructure upgrades at the bulk T&D level. Additionally, this topic covered controls and communications upgrades needed for efficient operation of a high-renewables system. The topic leveraged the technical results of the resource adequacy, production cost modeling, transmission analysis, and distribution analysis (Sections 8, 9, 10, and 11).

System Resilience, Reliability, and Recovery: power system resilience, reliability, and recovery attributes and identified key actions needed to bolster the system robustness to threats (e.g., hurricanes, floods, and earthquakes) and enhance day-to-day operations. PR100 focused on studying the reliability of the future system via resource adequacy and production cost modeling (Sections 8, 9, 10, and 11). Resilience and recovery to threats are key objectives when planning for a future system that is subject to increased threats and long-duration grid outages.

Community Resilience, Climate, and Energy Justice: implementation actions to address the challenges seen at the community level while addressing the climate impacts and energy justice implications. PR100 extensively evaluated the energy justice and social burden implications the Puerto Rico energy transition will have on society today and into the future (Sections 3 and 14). Furthermore, the impact of climate change on the infrastructure was studied closely and the technical results were used to inform the implementation actions in the Roadmap (Section 13). Lastly, ensuring communities were actively engaged to participate in discussions around enhancing the resilience at the community level was a common practice throughout PR100 via continued stakeholder engagement efforts (Section 2).

Economic Development and Workforce Development: economic and workforce development impacts that are prevalent with the Puerto Rico energy transition throughout the planning horizon of PR100. This topic leveraged the detailed analysis related to the retail rate analysis, macroeconomic analysis, and workforce implications that were studied in PR100 (Section 12).

17.1.6 Roadmap Summary and Section Organization

Figure 427 provides a summary of the Roadmap including several components to summarize the main aspects of this section. The main components shown include the high-level goals for each time-period, the themes that summarize the actions across each time period, the corresponding action areas, and the recurring actions. The themes for each time-period and the recurring actions are further expanded upon by identifying specific actions, which are discussed in Sections 1.1 through 17.6 . For each time period, two distinct sets of actions are identified: actions that are directly supported by the findings of PR100 and additional considerations, which are actions that are viewed as best practices as suggested by subject matter experts and stakeholder engagement and can be indirectly implied by PR100 findings. For each action, the corresponding action areas are identified to provide additional context. Stakeholder groups are also identified for each action to provide detail into which stakeholder groups should take which actions to implement the energy transition.

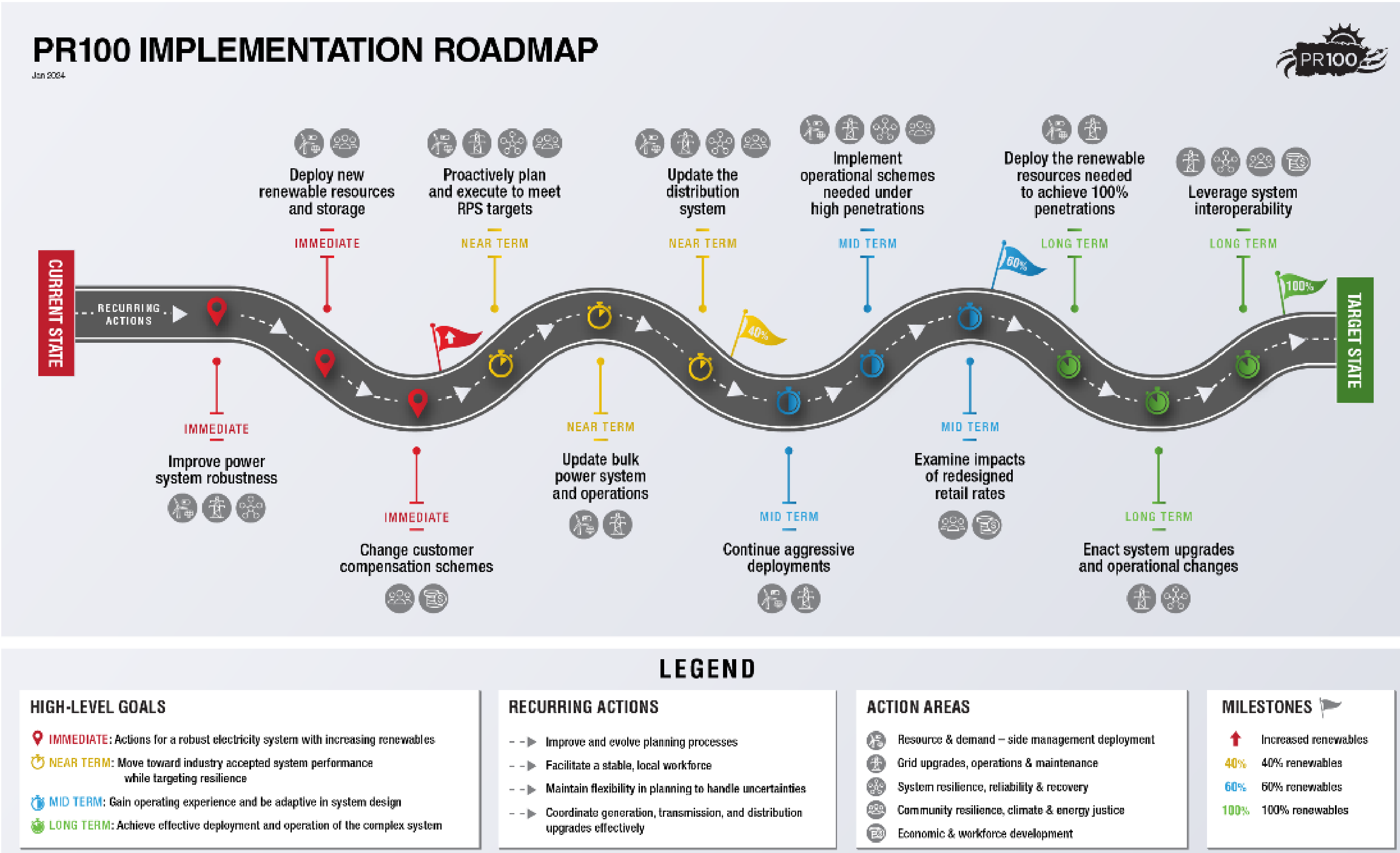


Figure 426. PR100 Implementation Roadmap summary

17.2 Immediate Actions for a Robust Electric System with Increasing Renewables

Table 72 describes the immediate implementation actions identified by the PR100 project team. These actions are efforts that could be undertaken right away to help progress the electric system toward a future state that will increase system robustness and enable high penetrations of renewable energy.

Table 72. Immediate Actions Identified by PR100

Action	Action Areas	Stakeholders
Improve power system robustness by increasing capacity and making urgent repairs.		✓ Utility and Grid Operators ✓ Renewable Developers ✓ Energy Regulators
Deploy new renewable resources and storage via stakeholder-driven pathways.		✓ Utility and Grid Operators ✓ Renewable Developers ✓ Customers and Communities
Change customer compensation schemes to incentivize temporal-based charging and discharging among stakeholders.		✓ Utility and Grid Operators ✓ Energy Regulators

17.2.1.1 Rationale for Actions

Improve power system robustness by increasing capacity and making urgent repairs.

The power system in Puerto Rico requires immediate upgrades to improve performance to acceptable levels. The power system is considered fragile across all levels—generation, transmission, and distribution—which manifests as poor reliability, inefficient operation, and vulnerability to extreme events (e.g., hurricanes, floods, and earthquakes). There is an immediate need to make the system robust by building new capacity and updating T&D system operations, controls, and hardware. These changes can be implemented both as legacy infrastructure is reconstructed and as new resources are deployed. Urgent repairs needed include fixing falling poles and failed hardware, increasing system capacity to have enough generation for peak system loads and to increase redundancy, and upgrading distribution feeders to higher voltage.

Deploy new renewable resources and storage via stakeholder-driven pathways.

PR100 results confirm an immediate need for new resources on the current system to stabilize the grid and alleviate current generation shortfalls, including rapid deployment of utility-scale and distributed renewable resources and significant amounts of storage to address current system issues and contribute to reaching 40% renewables. Specifically, PR100 found that significant amounts of utility-scale renewables would need to be deployed to meet the renewable energy goals. Yet few new utility-scale projects have progressed in Puerto Rico in recent years in part due to stakeholder concerns about siting and impacts of new projects. Thus, identifying and executing stakeholder-driven pathways to enable accelerated deployment is needed immediately to overcome generation capacity shortfalls and enable increased renewable penetration. The technologies deployed immediately will likely be mature technologies that have proven operability within the Puerto Rico power system. PR100 analysis identified sufficient land area for the needed renewable capacities, even when excluding potentially controversial areas such as those zoned for agricultural use (Section 4, page 59). Because of the sensitivity of land use regarding utility-scale resources, careful consideration of land used for renewable development should be given to exploring a wide range of siting decisions for candidate resources via stakeholder-approved pathways. This consideration is crucial to most deployments that will occur over the next several decades as Puerto Rico transitions to the target state.

Change customer compensation schemes to incentivize temporal-based charging and discharging among stakeholders.

PR100 results point to long-term impacts of current customer compensation in Puerto Rico (Section 12, page 401). Specifically, there is no incentive for customers to use their batteries in a grid-interactive fashion, and there can be equity concerns about electric rates paid by customers who own DERs systems versus those that do not. To address near-term distribution hosting capacity concerns and long-term rate concerns, there is an immediate need to incentivize temporal-based charging and discharging of customer-owner storage systems to increase hosting capacity and better align compensation for customer generation with its value to grid operation. The Battery Emergency Demand Response Program piloted by LUMA is an initial effort that can be leveraged and built upon to address this immediate action (LUMA 2023c).

17.3 Near Term: Move Toward Industry-Accepted System Performance While Targeting Resilience (Transitioning to 40% Renewables)

In the near term, to achieve 40% renewable penetrations, the stakeholders of Puerto Rico must act quickly to not just increase renewable penetrations but also move the system toward accepted system performance while increasing system resilience to extreme meteorological events and natural hazards. The near-term actions are based on PR100 findings and best practices, which are the result of a combination of subject matter expert input and stakeholder engagement. The actions are further categorized by the Roadmap action areas and the corresponding stakeholders.

17.3.1 Actions Supported by PR100 Findings

Table 73 breaks down the near-term actions identified and implied by the findings of PR100. The table is followed by the rational for the actions.

Table 73. Near-Term Actions Identified by PR100

Action	Action Areas	Stakeholders
Proactively plan and execute to meet future renewable portfolio standard (RPS) targets.		✓ Utility and Grid Operators ✓ Energy Regulators ✓ Renewable Developers ✓ Customers and Communities
Deploy multiple gigawatts (GW) of renewable resources and storage at all scales to meet the 40% RPS target.		✓ Utility and Grid Operators ✓ Energy Regulators ✓ Renewable Developers
Rapidly design and implement energy efficiency programs to achieve the Act 17 energy efficiency goal.		✓ Utility and Grid Operators ✓ Energy Regulators ✓ Customers and Communities
Update operational strategies, including enhanced forecasts, to gain foundational knowledge and prepare for future system operational challenges.		✓ Utility and Grid Operators
Establish requirements for grid-forming inverters and enable black-start controls of energy storage to lay the foundation for future high-renewables systems.		✓ Utility and Grid Operators ✓ Renewable Developers
Continue to study and upgrade the lower-voltage (38-kV) transmission network to accommodate new resources and mitigate potential issues.		✓ Utility and Grid Operators ✓ Energy Regulators
Deploy storage at critical points in the distribution system to mitigate current and future power flow violations.		✓ Utility and Grid Operators ✓ Renewable Developers
Deploy utility-scale storage to support bulk power system resilience.		✓ Utility and Grid Operators ✓ Renewable Developers

Action	Action Areas	Stakeholders
Prioritize feeder upgrades, including updating control schemes and protection, to support equitable, resilient, and reliable solutions.		✓ Utility and Grid Operators ✓ Renewable Developers
Establish education and workforce programs to develop sustained workforce to support the energy transition.		✓ Renewable Developers ✓ Customers and Communities
Expand financial assistance programs to promote equitable deployments of customer-owned resources.		✓ Energy Regulators ✓ Customers and Communities
Study electric rate designs to understand equity economic growth considerations.		✓ Energy Regulators ✓ Customers and Communities

17.3.1.1 Rationale for Actions

Proactively plan to meet future renewable portfolio standard (RPS) targets.

A key near-term action for the Puerto Rico stakeholders is to proactively plan to meet future RPS targets. Act 17 sets RPS and energy efficiency targets for 2025, 2040, and 2050. These targets are spread out across long time spans and, if followed verbatim, might result in start-stop deployment, with spikes in deployment occurring immediately before target years and lulls in deployment happening in other years. Such uneven rates of deployment are seen in the resource expansion modeling results. Uneven rates of deployment can also have significant economic impacts and affect the local workforce, as outlined in the economic analysis (Section 8, page 209). To avoid such effects, the stakeholders of Puerto Rico must be proactive and plan for future resource investments to ensure Act 17 targets are met in a steady manner. Such efforts could include setting annual RPS goals to ensure an efficient build-out of resources and a sustainable workforce. In fact, PREB proposed such annual RPS targets in recent draft regulation (PREB 2023a). This action is listed as a near-term priority because future Act 17 targets build on this consideration. All stakeholders of the Puerto Rico energy system will contribute to this planning effort, though it will be led by regulators who set and define RPS targets.

Additionally, reevaluation of the RPS in Act 17 may be needed. This would be in alignment with a proposed regulation from PREB regarding regulation of renewable energy certificates compliance with the RPS, which would establish annual targets starting in 2024 and procedures and penalties for noncompliance (PREB 2023a). Actions to consider in reevaluation include setting goals in energy (MWh) to match procurement requirements, providing clear guidance on renewable energy certificates to include the measurement of distributed PV in RPS requirements, and clearly defining impacts for missing RPS targets to increase accountability.

Deploy multiple gigawatts (GW) of resources to address current issues and meet the near-term RPS target.

PR100 identified a range of resources required to meet the near-term 40% RPS goal (see Section 8, page 209). The exact capacities required of all resources—which include wind, utility-scale solar, and various durations of energy storage—are highly dependent on the scenario modeled. However, themes emerge across all scenarios, such as that deploying utility-scale renewables can reduce near-term costs (see Section 12, page 401) and that adding additional capacity on the system will mitigate capacity shortfalls. However, as discussed in Section 10 (page 267), limiting the size of single utility-scale resources and storage units should be considered to benefit reliability and resilience in the future. Additionally, spreading generation across the territory can assist with grid recovery. While this action is similar to the immediate term, the near term will require more capacity to reach the near-term RPS target and will consist of mature technologies with the possibility of small-scale emerging technologies.

Rapidly design and implement energy efficiency programs.

Act 17 mandates a 30% improvement in energy efficiency by 2040. Therefore, near-term planning must include development of an energy efficiency program for customers to adopt in the near term to mid term. Using a bottom-up analysis, PR100 found that energy efficiency adoption will provide only an 18% improvement by 2040 (Section 5, page 117). Significant planning and implementation of energy efficiency programs must take place to meet the Act 17 target including building on efforts already undertaken, such as LUMA's Transition Period Plan for Energy Efficiency and Demand Response. This may require stakeholders to reevaluate current programs, assess technology potentials to help meet these goals, or seek other options to reduce demand including demand response programs.

Establish updated operational strategies, including enhanced forecasts, to gain foundational knowledge and prepare for future system operational challenges.

PR100 identified a near-term need to upgrade the operational aspects of the system with advanced scheduling procedures as more renewables and energy storage come onto the system (Section 9, page 241). Due to the variability and short-term forecast errors that exist with renewable resources and the frequent lack of operational reserves in the current Puerto Rico system, the scheduling procedures for resource dispatch must be updated. By updating scheduling procedures, load shedding events can be mitigated when there are extended periods of low renewable energy generation time periods (e.g., 3 days of cloudy weather). Additionally, the system will require a significant amount of energy storage to firm the renewables in all phases of the Roadmap. The energy storage technologies will vary in duration (4, 6, 8, and 10+ hour). Therefore, the scheduling configuration for real-time dispatch and day-ahead unit commitment must be updated to account for the operational characteristics that energy storage technologies will provide, such as multiday scheduling procedures. The updated operating schedules should be formed early so utility and grid operators can gain experience and prepare to adapt and revise operating procedures with longer forecasting horizons to mitigate future energy shortages.

Establish requirements for grid-forming inverters and enable black-start controls of energy storage to lay the foundation for future deployment.

Grid-supporting technologies—such as grid-forming (GFM) inverters, energy storage, and frequency/voltage—will be important for renewable installations (see Section 10, page 267), and technical requirements for such systems should be expanded. To support this action, researchers from several national laboratories, universities, and DOE outlined a research roadmap for GFM inverters (Lin et al. 2020). Additionally, the Energy Systems Integration Group developed a report that discusses GFMs and their integration into the energy systems with high inverter-based resources (IBR) to support this action (Matevosyan and MacDowell 2022). Institute of Electrical and Electronics Engineers (IEEE) 1547 Category 3 relay settings for DERs were a specific recommendation. Meeting this requirement, and requiring DERs to be robust to voltage deviations, would avoid unnecessary disconnections during and after transmission faults. At the utility scale, renewables and battery storage should have robust settings for low- and high-voltage ride-through capabilities. Inverter controls, such as batteries with GFM inverters, could immediately improve system reliability. It is also suggested to adopt IEEE 2800 Standard for IBR and define Puerto Rico-specific requirements for inverter operation, especially GFM inverters. Such standards are a starting point: additional efforts related to establishing operational modes and settings will be needed.

PR100 found that in the near term, energy storage with GFM inverters can contribute significantly with primary frequency control (see Section 10, page 267). Installing GFM and black-start controls on energy storage and grid-supporting controls in all renewable generation with connection to an automatic generation control system can result in acceptable performance for large generation contingencies. By providing frequency control and evening ramping support, energy storage can significantly improve near-term grid reliability even before large amounts of renewables are installed. By installing GFM energy storage with black-start capabilities, utility and grid operators can gain operational experience to prepare for future renewable penetrations.

Continue to study and upgrade the lower-voltage (38-kV) transmission network to accommodate new resources and mitigate potential issues.

PR100 found there will be issues in the lower-voltage (38-kV) transmission networks as more resources are built and connected to 38-kV networks to meet planning objectives (see Section 9, page 241). Options to alleviate some of the 38-kV network issues include optimal siting of resources on the 38-kV system based on its existing capacity, exploring non-wires alternatives, and pursuing opportunities for topology control to improve the utilization of the high-voltage networks (e.g., 115 kV and 230 kV). This planning action is identified as both a near-term action and a mid-term action to be performed by the utility with assistance from the research community, and execution should be extended into the long term due to the number of resources that will come online to reach 100% renewables. PR100 performed initial studies based on select network topologies, but several possible configurations possible could affect the severity of issues on the lower-voltage network.

Deploy storage at critical points in the distribution system to mitigate current and future power flow violations.

PR100 found there will be reverse power flow as early as 2024 in some feeders across the Puerto Rico system (Section 11, page 347). A proposed solution to this issue is to leverage customer-owned storage and utility-controlled storage that can be sited at optimal locations along the feeders to handle the excess energy. Utility-controlled storage alone can mitigate most of the hosting capacity concerns with high penetrations of renewables on the distribution system. However, this may be a high-cost solution, especially if the customer-owned storage is not used. Optimization of battery sizing and incentivization for utilization of customer storage in a grid-interactive way will increase efficiency and reduce costs. This action will require close coordination by the utility, the developers, and the customers.

Deploy utility-scale storage to support bulk power system resilience.

As noted in Section10, deploying utility-scale energy storage in the near term can support bulk power system resilience if it is sited and sized optimally. Utility-scale energy storage can provide additional reliability benefits if the proper GFM controls and black-start capabilities are deployed and validated. In the near term, utility-scale storage technologies will likely be mature technologies with durations ranging from 4 to 10 hours. While this action is highlighted in the near term, PR100 found storage will play a critical role across a variety of applications in the energy transition and, therefore, is also highlighted as a recurring action.

Prioritize feeder upgrades, including updating control schemes and protection, to support equitable, resilient, and reliable solutions.

PR100 found the current distribution system can have voltages higher than ANSI standards—even at night, when no distributed PV systems are generating—due to older capacitors on the distribution system. Additionally, several distribution feeders in Puerto Rico operate a low voltage (4 kV), which limits feeder capacity and flexibility. As distributed PV systems are added, operational challenges are multiplied. PR100 found that to keep distribution feeders at safe operating voltages, capacitors need to be controlled or removed if they no longer support system needs. Enhanced visibility of distribution system operation is required to enable understanding of where and when concerns (e.g., reverse power flow and voltages outside of safe ranges) are occurring. And upgrades of the low-voltage distribution feeders to higher voltage would be prudent for better service and added flexibility. Feeder upgrades can be executed in a manner that supports equitable, resilient, and reliable solutions. This involves working with developers, customers, and communities to ensure the upgrades equitably benefit the stakeholders across Puerto Rico.

Establish education and workforce programs to develop sustained workforce to support the energy transition.

Investment in education programs in the near term would ensure a well-trained and skill-diverse workforce to address the many types of work required for the upcoming energy transition. Workforce development should be seen as a multidecade effort and carefully planned to ensure a sufficient labor force—comprised of installers, operators, and others—is available each year, as supported by the findings of the economic impact analysis in PR100 (Section 12, page 401). Workforce development efforts should be coordinated with industry and education stakeholders. University-level and vocational curricula should continue to evolve to meet the system needs. Through various stakeholder engagement sessions, several stakeholders indicated there is an immediate need for all stakeholders to become more educated in how to operate and maintain renewable systems. All stakeholders should become more familiar with renewable energy benefits, challenges, and limitations in a dynamic manner to allow for implementation of new technologies as they mature. This action is directly related to the recurring action of maintaining a stable, local workforce.

Expand financial assistance programs to promote equitable deployments of customer-owned resources.

PR100 economic impact analysis found expansion of financial assistance programs might be needed as early as 2025 to offset adverse economic impacts (Section 12, page 401). This is identified as a near-term action due to the near-term impacts low- to very low-income customers may experience. Several funding mechanisms—including the Puerto Rico Department of Housing's New Energy and Solar Incentive Programs funds[217] and DOE's Puerto Rico Energy Resilience Fund (PR-ERF)[218]—have been announced to promote the adoption of renewable energy systems, and these are often focused on lower-income customers. Additional retail rate discounts may need to be offered to low-income customers who do not have their own renewable energy systems to mitigate the impacts of higher rates, which may occur for non-adopters as more customer-owned systems are adopted (Section 12, page 401).

Study electric rate designs to understand equity economic growth considerations.

Designing and implementing an excess generation compensation structure for customer-owned generation that is fair for PV and non-PV owners alike could be important (Section 12, page 401). This action, which is built on an immediate action, is intended to design fair rates for customers who do not own distributed PV systems. Compensation structures can be evaluated for their ability to incentivize increased loads during the day and reduced loads at night while remaining equitable. Rate structures can be designed to enable increased distribution system hosting capacity while still compensating customers for their generation.

17.3.2 Additional Considerations

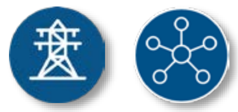
Table 74 provides the near-term actions that are considered best practices and should be considered as the Puerto Rico power system undergoes the transition to renewable energy.

Table 74. Near-Term Actions Identified as Best Practices

Action	Action Areas	Stakeholders
Identify small- to mid-scale emerging technologies projects to prepare for large-scale deployments.		✓ Utility and Grid Operators ✓ Renewable Developers
Identify and implement solutions to bolster community resilience via microgrids, meeting critical loads during outages, and effectively executing disaster plans.		✓ Utility and Grid Operators ✓ Energy Regulators ✓ Renewable Developers ✓ Customers and Communities

[217] "New Energy Program," https://nuevaenergia.pr.gov/en/

[218] "Puerto Rico Energy Resilience Fund," DOE, https://www.energy.gov/gdo/puerto-rico-energy-resilience-fund

Action	Action Areas	Stakeholders
Increase system resilience and recovery by ensuring new transmission, distribution, and generation resources can withstand winds of 160 mph and systems are designed for effective black-sky operation.		✓ Utility and Grid Operators ✓ Renewable Developers
Modernize the grid with high-fidelity sensors and advance metering infrastructure; develop new models for detailed power system studies; and leverage collected data to enable better system visibility, faster outage detection, and more efficient billing.		✓ Utility and Grid Operators ✓ Renewable Developers ✓ Customers and Communities
Leverage dependency and social burden mappings to drive specific investments in the power system.		✓ Utility and Grid Operators ✓ Energy Regulators ✓ Customers and Communities
Implement virtual power plants (VPPs) and demand-side management to prove feasibility and operability.		✓ Utility and Grid Operators ✓ Renewable Developers ✓ Customers and Communities

17.3.2.1 Rationale for Actions

Identify small- to mid-scale emerging technologies to prepare for large-scale deployments.

To reach the long-term energy system goals in Puerto Rico, significant efforts must be taken to identify and assess the feasibility of small- to mid-scale emerging technologies. There is significant uncertainty in the available technology in future years (Section 15.5, page 577), and significant planning and demonstration must be taken, starting with the identification of such technologies in the near term. First, stakeholders must identify technologies that can satisfy current and future needs (SNL and LANL 2023). This requires working closely with industry and research organizations to confirm (1) the feasibility and viability of emerging technologies and (2) that such technologies can provide reliable and resilient power at a cost that benefits ratepayers. In the near term, it is critical that the small- to mid-scale emerging technologies are identified and corresponding demonstration projects are set up to identify potential for large-scale deployment from the mid term to the long term. While emerging technologies can include a suite of technologies yet to be proven at full grid-scale deployment, such technologies can include long-duration energy storage technologies[219] and dispatchable renewable resources (e.g., biodiesel; Section 15.5, page 577). While all stakeholders play a role in technology adoption in Puerto Rico, utility and developer stakeholders can take near-term action to prepare for large-scale deployment in future years.

Identify and implement solutions to bolster community resilience via microgrids, meeting critical loads during outages, and effectively executing disaster plans.

PR100 found that up to 1.5 GW of rooftop PV will be adopted by customers. With this rapid deployment of distributed resources there are significant opportunities to coordinate microgrid development throughout Puerto Rico. Microgrids can provide power to critical loads and improve systems operation during outages. Careful coordination among utilities, developers, and customers/communities will result in effective solutions that benefit a wide range of stakeholders in Puerto Rico.

PR100 and previous studies laid the foundation for this action by identifying infrastructure locations providing critical *services* to people (Section 14, page 539; Jeffers et al. 2018). The next step, to be performed in the near term through close collaboration between the utility and customers, is to identify critical *loads.* Performing this load analysis at the household level will help accurately size back-up generation and storage solutions for critical loads during outages and avoid costly solutions that provide redundant power for noncritical loads. The selection of services to keep powered during an outage should be based on equitable access and be threat-informed. Critical services within communities with fewer services (and less redundancy of services of the same category) and/or communities with more vulnerable populations (e.g., lower financial means, mobility limitations, or medical fragility) should be prioritized. Community-level investments, like community solar or community microgrid projects, should ensure all critical services are available during normal conditions and grid outages. For individual households, quantifying critical loads at the household level can help size PV and storage systems more appropriately.

PR100 stakeholders identified establishments of energy disaster plans as a near-term need. Energy emergency plans are already required and exist in Puerto Rico, and they should continue to include vulnerable communities. The Emergency Response Plan developed by LUMA is an approach to start addressing this near-term action; it was developed to address the needs of critical facilities and identify the critical services to be prioritized when restoring services (PREB 2023a). Emergency plans that incorporate upcoming changes to the energy system should be developed and validated against current system plans, and they should emphasize restoration procedures using black-start opportunities provided by renewables.

Increase system resilience and recovery by ensuring new transmission, distribution, and generation resources can withstand winds of 160 mph and systems are designed for effective black-sky operation.

Through analysis and active stakeholder engagement, PR100 identified the need to continue the adoption of the Puerto Rico standards for grid hardening of new and existing infrastructure. For example, new transmission, distribution, and resources could be built to withstand winds of

[219] "Long Duration Storage Shot," DOE, https://www.energy.gov/eere/long-duration-storage-shot

160 mph. Additionally, immediate resilience upgrades are needed to address the fragility of the system during blue- and black-sky conditions. Black-sky conditions refer to the conditions during grid outages after a storm where renewable resources may be adversely affected (Jackson and Gunda 2021). Establishing grid hardening standards and making immediate resilience upgrades to the system will serve as a foundation for the development of a resilient system in the future.

When sizing PV and storage to meet critical loads, it is crucial that the resources designed to meet those critical loads are adequately sized and operated continuously during grid outages. Black-sky events require careful operation of the system to serve the critical loads through the duration of the outage. Black-sky system operation requires significant planning, operational consideration, and end-user education to ensure the systems are properly used during an event. Black-sky planning considerations can be broadly applied to both the transmission system and the distribution system.

Modernize the grid with high-fidelity sensors and advance metering infrastructure; develop new models for detailed power system studies; and leverage collected data to enable better system visibility, faster outage detection, and more efficient billing.

Collecting the necessary data using high-fidelity sensors across the grid is critical to enabling grid modernization. As observed in simulations and discussed in Section 10 (page 267), large frequency deviations might appear from fault-induced delayed voltage recovery (FIDVR), from air conditioning motor load stalling, followed by DERs tripping due to low voltage levels. To enable higher visibility of FIDVR events in Puerto Rico, high-resolution measurements sensors (e.g., phasor measurement units) at the transmission level should be installed. The composition of certain loads, such as air conditioning, should be studied and adoption of variable frequency drive (VFD) air conditioner units should be considered (it is important to note VFD are being installed in Puerto Rico, but the amount of legacy air conditioning, now and in the future, is uncertain). VFD units would help avoid the stalling effect that could cause voltage instability. Improvements to associated communication infrastructure can facilitate reliability and stability enhancement activities. This is primarily intended for the utility to gain additional insights into the system's performance; however, a wide range of stakeholders, including the research community, will benefit from the high-quality data. In addition to mitigating FIDVR, implementing real-time high-resolution grid measurement systems (phasor measurement units) and associated communication infrastructure can facilitate various reliability and stability enhancement activities, such as generation and storage model validation, contingency event investigation including undesired DERs and utility-scale, inverter-based resource tripping, oscillations and resonance, as well as real-time situational awareness.

At the distribution system level, advanced metering infrastructure can enable both faster outage detection and better modeling, including detection of the performance of renewable energy systems, and it can streamline billing. Advanced metering infrastructure will also be required if any time-of-use rates are implemented, including varying compensation for customer generation based on time of day.

Additionally, there is a need to develop modeling to simultaneously evaluate distribution-grid and transmission-grid control strategies during blue-sky conditions and threats. Better forecasting methods and updated operating reserves are required to maintain reliable system operation. Additional studies of protection system upgrades to tolerate reductions in grid strength are also needed.

Leverage dependency and social burden mappings to drive specific investments in the power system.

PR100 identified dependencies between critical assets in the water and power sectors across Puerto Rico (Section 14, page 539). PR100 also performed a social burden analysis, which considered access to critical services when the grid is operating at full capacity and in the event of alternative large outage scenarios. The findings of these parallel efforts pinpoint where the implementation of grid hardening, or outage mitigation measures, would be the most impactful to reduce the social burden of outages and would provide the most value to Puerto Rico communities. Energy-dependent infrastructure should have redundant service-level connections and/or connections to multiple generation sources to mitigate the potential for cascading failures that will scale up the consequences of outages.

Explore implementation of virtual power plants and demand-side management to prove feasibility and operability.

Virtual power plants (VPPs) are considered to be an aggregation of DERs that allows for demand flexibility to meet the grid's needs. When several DERs—which can include distributed solar, distributed storage, electric vehicles (EVs), and smart thermostats—are coordinated via a VPP, they can provide energy services similar to a traditional power plant (Martin and Brehm 2023). VPPs may provide monetary benefits to customers by providing compensation and incentives for participating in the VPP. Furthermore, VPPs may reduce operational and fuel costs on the system by peak-shifting demand services.

VPPs are beginning to be implemented and tested in Puerto Rico, with an emphasis on disadvantaged communities, to evaluate the feasibility of VPPs (DOE 2023). PR100 did not explicitly study the feasibility of VPPs but they might provide several energy services, though still uncertain, needed to address key grid challenges. Additionally, several other demand-side management programs may provide opportunities to address several operational challenges in the near term and future periods. Such programs can include demand shifting, demand reduction, and DERs management. These programs, which were not explicitly studied in PR100, will require detailed analyses and testing to prove their feasibility and operability. Therefore, stakeholders—including the utility, developers, and customers/communities—might explore the potential for such programs in Puerto Rico by small-scale testing to prepare for adoption in the future. This action has been started by several stakeholders in Puerto Rico and includes the continuation of LUMA's Battery Emergency Demand Response Program in addition to new programs.

17.4 Mid Term: Gain Operating Experience and Be Adaptive in System Design (Operating with 40%–60% Renewables)

In the mid term, the system will operate with 40%–60% renewables. While significant uncertainty about the system topology and resource mix remains, including uncertainty about siting of resources across the territory, now is the time for stakeholders to gain valuable operating experience of a high-renewables system and with the implementation of small-scale demonstration projects of emerging technologies. Furthermore, the mid term is one period when stakeholders must be adaptive in system design using lessons learned from the immediate and near term and leveraging changes in climate, technology, consumer behavior, and community priorities. In this section, several mid-term actions based on PR100 findings are discussed and identified as best practices.

17.4.1 Actions Supported by PR100 Findings

Table 75 introduces the mid-term actions identified by PR100, including the crosscutting action areas and the corresponding stakeholders. Rationale for the actions is also discussed in this section to provide more context.

Table 75. Mid-Term Actions Identified by PR100

Action	Action Areas	Stakeholders
Continue aggressive deployments of renewable resources, including significant amounts storage and energy efficiency to meet mid-term targets of Act 17.		✓ Utility and Grid Operators ✓ Energy Regulators ✓ Renewable Developers ✓ Customers and Communities
Implement advanced forecasting and upgraded operations to support resilience and reliability to gain operating experience.		✓ Utility and Grid Operators
Upgrade lower-voltage (38-kV) transmission network to accommodate new resources based on near-term findings and resource expansion.		✓ Utility and Grid Operators
Expand black-start and advanced controls capabilities to continue testing in renewable resources and storage.		✓ Utility and Grid Operators ✓ Renewable Developers
Harden the power system at nodes where the various infrastructures and the power system share interdependencies continue to enhance system resilience.		✓ Utility and Grid Operators ✓ Renewable Developers ✓ Customers and Communities
Examine impacts of redesigned retail rates and distributed generation compensation schemes and modify as needed to achieve efficient system operation and more equity among customers.		✓ Energy Regulators ✓ Customers and Communities

Action	Action Areas	Stakeholders
Incorporate synchronous condensers and continue studies to handle high renewable penetrations in the mid term and prepare for the long term.		✓ Utility and Grid Operators ✓ Renewable Developers

17.4.1.1 Rationale for Actions

Continue aggressive deployments of renewable resources, including significant amounts storage and energy efficiency to meet mid-term targets of Act 17.

PR100 identified a range of resources required to meet the mid-term goal of the 60% RPS target. While the PR100 modeling does not show significant build-outs to meet the 60% goal, stakeholders continue to proactively plan and deploy new resources to meet the mid- and long-term RPS goals. PR100 identified significant resource investments in the near and the long term (40% and 100% RPS goals respectively) compared to the 60% RPS target (Section 8, page 209). However, this does not promote a smooth build-out and may not be feasible given workforce and supply chain constraints. Therefore, adequate renewables and storage must be deployed to meet the 60% target and it is suggested that additional capacity come online to prepare for the long-term goal of 100% renewables. Specifically in the mid term, there is the opportunity to deploy emerging technologies in small- to mid-scale installations to gain experience with their operation and interactions with other generation sources. Such efforts would not be as appropriate in the near term, where capacity needs are so dire that established technologies should be implemented in the interest speeding deployment, nor in the long term, when currently emerging technologies will have become established and will need to be installed in large quantities, whether or not the system operators are ready for them.

In the mid term, the Act 17 goal of 30% improvement in energy efficiency must be met. This will require the adoption and implementation of the energy efficiency programs identified and tested in the near term. PR100 found that significant efforts must be taken to reach the Act 17 energy efficiency goal, which includes rapid adoption of energy efficiency programs and possible restructuring of current energy efficiency programs to better align with the Act 17 goals. Furthermore, demand response programs and energy savings technologies could emerge as promising solutions during this period and stakeholders should remain informed of such solutions to ensure rapid deployment of viable solutions.

Implement advanced forecasting and operations to support resilience and reliability to gain operating experience.

In the near term, the utility stakeholders should clearly identify the operating reserve requirement and scheduling procedures required to operate a high-renewables system. In the mid term (and again in the long term), these updated procedures should be implemented and tested to identify the viability and flexibility to navigate the operation of the complex system. Additionally, as longer-duration storage technologies are deployed, the scheduling procedures and operating reserve requirements might need to adapt to ensure the technologies are being dispatched economically and reliably.

Upgrade lower-voltage (38-kV) transmission network to accommodate new resources based on near-term findings and resource expansion.

PR100 found there will be issues in the lower-voltage (38-kV) transmission networks as more resources are built to meet the several planning objectives (Section 9, page 241). Such upgrades and recommendations to alleviate some of the 38-kV network issues include optimal siting of resources on the 38-kV system, exploring non-wires alternatives, and pursuing opportunities for topology control to improve the utilization of the high-voltage network utilization (e.g., 115 kV and 230 kV). Increasing network capacity by reconductoring or expanding the transmission network is another option, though is anticipated to be the most costly solution This action is identified as a mid-term action to be performed by the utility with assistance from analysis from the research community, and it should be extended into the long term due to the generation capacity that will come online to reach 100% renewables.

Expand black-start and advanced controls capabilities to continue testing in renewable resources and storage.

By the mid term, black-start capabilities should be enabled for most energy storage systems (Section 9, page 241). In the mid term, renewables (both utility-scale and distributed) should begin to participate in grid recovery. This inherently requires renewables to have GFM controls and black-start capabilities. To gain operational experience, the use of storage and renewables to black-start using advanced controls should be explored via small-scale implementation projects. This could reduce the dependency of conventional generation, which may be retired, during grid recovery processes. Additionally, researching the role of DERs in the grid recovery process is essential to ensure all resources can participate in grid recovery in the long term.

Most existing grid-connected, inverter-based renewable energy generators are meant to be responsive to the grid—following grid frequency and shutting off if abnormalities are detected on the grid such as grid voltage or frequency being outside acceptable levels. However, as Puerto Rico transitions to 100% renewables, new operating schemes for inverter-based generators, including functions such as voltage and frequency ride-through and GFM functionality will become increasingly necessary. Even when annual inverter-based generation penetrations are still increasing (e.g., 40% of annual energy), instantaneous inverter-based generator penetrations may reach 100%, such as around noon on a sunny day with lower load. Especially in these scenarios, having sufficient GFM inverters and having all inverters support voltage and frequency ride-through will be essential to operating a robust grid.

Harden the power system at nodes where the various infrastructure assets and the power system share interdependencies.

Having completed preliminary critical service mapping in the near term and secured back-up power or rapid restoration for critical services serving Puerto Rico's most vulnerable populations, the utility should work across domains with their counterparts to plan specific energy investments that harden the power system at nodes where the various infrastructures and the power system share interdependencies (Section 14, page 539). The plan should include critical infrastructure systems such as water/wastewater, transportation, and communications. Additionally, the rollout of these power system hardening investments should be prioritized based on social burden to ensure the minimal impact of outages on the people served.

Examine impacts of redesigned retail rates and distributed generation compensation schemes.

By the mid term, there will be a significant amount of customer-owned generation according to the PR100 distributed PV forecasts (Section 7, page 186). The impacts of redesigned retail rates and distributed generation compensation schemes should be examined soon. Not only should the impacts on customers who adopt distributed PV be studied, assessing the impacts on customers who have not adopted distributed PV is critical. In doing so, both subpopulations of customer are examined and stakeholders can revise the rate structures accordingly. This action would likely span the mid term as detailed implementation plans are selected for the rollout.

Incorporate synchronous condensers and continue studies to handle high renewable penetrations in the mid term and prepare for long term.

Placement of synchronous condensers (or equivalent alternative solutions) at high-voltage substations allows for wider short circuit improvement due to the low impedance. PR100 found that up to 1,600 MVA of synchronous condensers is needed for 100% inverter conditions. PR100 also found that placement of synchronous condensers at high-voltage substations may improve stability and allows for short circuit improvement. However, detailed studies are needed to assess other factors that can impact the stability (Section 10, page 267). Additionally, significant studies are needed to properly size and site synchronous condensers while simultaneously assessing alternative technologies, existing synchronous generators, and implementation cost. This is identified as a mid-term action for the utility to address the stability issues the grid is seeing and will see as more inverter-based resources come online.

17.4.2 Additional Considerations

Table 76 introduces the mid-term actions identified as best practices that can be considered for future planning as the system operates between 40% and 60% renewables and planning for the long-term goal of reaching 100% renewable penetration continues.

Table 76. Mid-Term Actions Identified as Best Practices

Action	Action Areas	Stakeholders
Deploy small- to mid-scale emerging and resilient resources to gain foundational knowledge.		✓ Utility and Grid Operators ✓ Renewable Developers
Perform resilience and recovery analysis on future operating conditions to better understand vulnerabilities and adapt future investments.		✓ Utility and Grid Operators

Action	Action Areas	Stakeholders
Evaluate and identify alternative dispatchable renewable resources to prepare for substantial investments in the long term.		✓ Utility and Grid Operators ✓ Customers and Communities
Study protection coordination for high-renewables systems to mitigate projected issues in the T&D system.		✓ Utility and Grid Operators

Resource & Demand-Side Management Deployment | Grid Upgrades, Operations, & Maintenance | System Resilience, Reliability, & Recovery | Community Resilience, Climate, & Energy Justice | Economic & Workforce Development

17.4.2.1 Rationale for Actions

Deploy small- to mid-scale emerging and resilient resources to gain foundational knowledge.

There is ample opportunity to deploy small- to mid-scale emerging and resilient resources in the mid term to gain foundational knowledge used for large-scale deployment in the long term. This action will be informed by the near-term identification and scoping of emerging technologies that can contribute to the energy transition and will include the actual deployment of such technologies to allow stakeholders to gain operational experience. If this action is taken, the future resource mix can be diverse and provide reliable and resilient power to the customers. This action will be informed by customers and community partners and should mainly be performed by the utility and developer stakeholders.

Perform resilience and recovery analysis on future operating conditions.

Resilience analysis, similar to the analyses detailed in Section 10.9 (page 335), should be performed on future operating conditions anticipated in the long term, including modeling of the system's response and recovery from threats that have significant impacts on the system performance. Resilience analysis is considered a mid-term action for stakeholders due to the evolving system resilience needs as more renewables are adopted. Also, significant research and development is required to study the participation of DERs in system recovery in the distribution system.

Evaluate and identify alternative dispatchable renewable resource.

PR100 identified the need for firm dispatchable renewable resources in the long term to meet the 100% renewable system. Such technology is loosely defined and not mature in today's market. Therefore, there is an urgency to evaluate and identify alternative dispatchable renewable resources, especially as more thermal baseload generators retire leading up to the long-term goals. This is closely related to the previous action in that small- to mid-scale deployments of emerging resources will assist in evaluating dispatchable renewable resources. It should also be noted that renewables—such as solar and wind, coupled with storage technologies that range in duration—could satisfy the requirements to ensure reliable operation in the future. Therefore, it is critical that the responsible stakeholders—namely the utility, regulators, and developers—must remain cognizant of the technologies that can both provide the required energy services and contribute to meeting the Act 17 RPS goals.

Study protection coordination for high-renewables systems to mitigate projected issues in the T&D system.

There is a need to assess the existing protection systems in the mid term as more inverter-based generation is deployed to further strengthen the grid. Significant studies should be performed to identify the correct protection coordination as the renewable penetration increases. As noted previously, the distribution system will see continued reverse power flow on feeders and the current setup at the substation level does not operationally allow for reverse power flow, including that reverse power flow can accelerate transformer loss of life and damage voltage control equipment. Additionally, by studying and improving the protection system, grid stability can be improved during severe faults. The utility, with the help from the research community, should study the protection schemes to mitigate issues that will arise in the mid term and the long term.

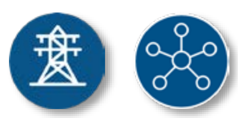
17.5 Long Term: Achieve Effective Deployment and Operation of the Complex System (Approaching 100% Renewables)

In the long term, the primary goals will be to achieve effective deployment of a diverse resource mix as the system approaches 100% renewable resources. Additionally, achieving efficient operation of the complex system is required in the long term to maintain the accepted level of performance that was developed and maintained in the near term and the mid term. In the long term, there is likely to be full-scale deployment of emerging technologies (e.g., long-duration energy storage technologies and dispatchable renewable resources) to support the highly variable system. This section describes the long-term actions that stakeholders of Puerto Rico can consider based on PR100 findings and best practices.

17.5.1 Actions Supported by PR100 Findings

Table 77 introduces the long-term actions based on the findings of PR100, and reasonings for these actions are discussed in this section.

Table 77. Long-Term Actions Identified by PR100

Action	Action Areas	Stakeholders
Continue deployments of renewable resources and storage to meet long-term RPS target.		✓ Utility and Grid Operators ✓ Renewable Developers ✓ Energy Regulators ✓ Customers and Communities
Implement long-duration storage and/or dispatchable renewable resource.		✓ Energy Regulators ✓ Utility and Grid Operators
Enact system upgrades as renewable resources increase in penetration and geographic variability to address issues of lower-voltage transmission network and provide voltage support.		✓ Utility and Grid Operators ✓ Renewable Developers ✓ Energy Regulators
Leverage system interoperability between loads such as increased EV adoption and variable generation.		✓ Utility and Grid Operators
Ensure the established advanced forecasting and operations procedures meet resilience and reliability goals as renewable resources increase.		✓ Utility and Grid Operators
Utilize all resources to enable black start of all assets in Puerto Rico energy system.		✓ Utility and Grid Operators ✓ Renewable Developers

17.5.1.1 Rationale for Actions

Deploy multiple gigawatts of resources to meet long-term RPS target.

The long-term RPS target is to reach 100% renewable energy by 2050. PR100 found this will require significant investments of mature and emerging technologies. While a 100% renewable energy future is possible, it relies on the deployment of utility-scale PV, wind, distributed PV, storage technologies, and flexible resources. To get from 60% to 100%, significant resource investments must occur and—to avoid sunk costs of the existing thermal fleet—there will be significant retirements. To replace the retirements of the baseload generation, there must be strategic deployment of resources to maintain reliability and affordability to customers. The required resources to meet 100% renewable energy varies based on the future scenario (Section 8, page 209).

PR100 identified the need for biodiesel, which provides significant flexibility for the high-renewables system. There is a substantial build-out required to go from 60% to 100%; however, the issue could be alleviated if stakeholders proactively plan for the future RPS targets by making significant investments and deployments on an annual basis. Across the PR100 scenarios the resource mix—which includes utility-scale and distributed resources—is found to be up to 19 GW in total installed capacity (Section 8, page 209). The resource mix should remain diverse and include significant investment in utility-scale resources coupled mainly with 4- and 10-hr energy storage. Across all scenarios, approximately 1 GW of biodiesel is selected to provide flexibility in the system. The massive deployments of resources will require a wide range of stakeholders to ensure resources are developed via stakeholder-driven pathways.

Implement long-duration storage and/or dispatchable renewable resource.

As the maturity of technologies in the long term is highly uncertain, implementation of technologies that provide dispatch flexibility to support reliable operation is needed. This action is closely related with the significant scoping and demonstrations efforts emerging technologies that can provide the energy services of thermal generation and remain a renewable resource to be compliant with Act 17. In the long term, stakeholders can use lessons learned and the foundational knowledge gained in the mid-term to make informed decisions on today's emerging technologies. This action is closely aligned with the previous action and should coordinated with the deployment of utility-scale renewable resources and DERs to ensure the solutions implemented are economically viable and equitable for customers.

Enact system upgrades as renewable resources increase in penetration and geographic variability to address issues of lower-voltage transmission network and provide voltage support.

PR100 found there will be congestion issues in the lower-voltage (38-kV) transmission network. Solutions include implementing non-wires alternatives, such as optimal siting of the resources within the 38-kV network and implementing the established topology control to improve the high-voltage network utilization. Additionally, while costly, increasing the capacities of the 38-kV network is a potential solution that would improve the overall reliability of the system and the hourly utilization of the transmission system. PR100 was unable to assess the viability of these solutions at the 38-kV level; therefore, these options are recommendations for the stakeholders to study in the future.

As discussed in Section 10, there is a need for additional voltage support equipment to compensate for voltage fluctuations and maintain voltage limits as more renewable resources are deployed on the system. Therefore, all utility-scale renewable generators and battery energy storage systems should provide voltage control. Specifically, voltage control compensation equipment might be needed to deal with voltage fluctuations from hour to hour at the 38-kV level. Voltage support equipment can include dynamic voltage control devices, such as STATCOM, SVC, synchronous condensers, and static voltage control equipment, such as capacitor and reactor banks (Section 10, page 267). This action will leverage several near- and mid-term actions that lay the foundation for implementing these additional system upgrades.

Leverage system interoperability between loads such as increased EV adoption and variable generation.

In the long term, EV adoption is projected to increase total system load by about 15% and can have a higher instantaneous contribution. EV loads are projected to increase the nighttime system peak load, and large amounts of PV generation are projected to decrease the system daytime minimum load. This will require efficient operation and deployment of long-duration storage and dispatchable renewable generation. However, this also presents the opportunity to integrate controllable loads into system operation. Controllable loads, including EV loads, can help consume load when generation is plentiful and can limit consumption when generation is scarce. This will help reduce storage capacity needs and congestion concerns.

Ensure the established advanced forecasting and operations procedures meet resilience and reliability goals as renewable resources increase.

In the long term, dispatchable renewable generation can be combined with the significant installation of long-duration storage, which will help provide power when wind and solar forecasts are inaccurate. For instance, extended cloudy weather will limit PV production, which could be offset by long-duration storage and/or dispatchable renewable generation. Continuing from the mid term, the combination of energy storage, renewables, and microgrids contributing to the black start recovery of the entire Puerto Rico energy system will be crucial. Additionally, implementing advanced forecasting and dispatchable technologies will be important to operate the energy system in the long term. As the system approaches 100% renewables, there will be significant amount of energy storage (4- to 10-hr duration) and dispatchable renewable generation (e.g., biodiesel). These technologies are not mature today, will be new to the Puerto Rico system, and will need to be operated using advanced scheduling procedures, which should be identified and tested in the near term and the mid term. In the long term, grid operators should fully deploy these advanced forecasting and scheduling procedures to operate the highly complex system to maintain reliability and dispatch resources economically.

Utilize all resources to enable black start of all assets in Puerto Rico energy system.

By the long term and as the system approaches 100% renewables, the black-start and recovery capabilities via GFM controls should be implemented for full-scale combined use of energy storage, renewables, and microgrids to black start the entire Puerto Rico energy system. Additionally, there will be significant large-scale implementation testing of system-wide black-start capabilities. As a result, the grid operators will gain experience operating the highly complex system and be able to navigate response and recovery in the event of system failures due to threats and large generator contingencies.

17.5.2 Additional Considerations

Table 78 introduces the long-term actions that can be considered best practices for the long term as the system approaches 100% renewables.

Table 78. Long-Term Actions Identified as Best Practices

Action	Action Areas	Stakeholders
Adapt planning processes and investment decision to mitigate climate-related effects on the grid.		✓ Utility and Grid Operators ✓ Renewable Developers ✓ Energy Regulators ✓ Customers and Communities
Explore potential for controlled EV charging to support grid.		✓ Utility and Grid Operators

17.5.2.1 Rationale for Actions

Adapt planning processes and investment decision to mitigate climate-related effects on the grid.

Climate change and other evolving factors will affect management, operation, and maintenance of the energy system. This is particularly true in the long term, as future work on end-of-century climate projections may point to increasing impacts currently not captured by climate modeling for mid-century (i.e., 2050). Utilities can mitigate these impacts by integrating climate awareness into grid planning processes and day-to-day utility operation. Adaptable disaster plans and resilience goals can evolve with the hazard landscape.

All stakeholders can further institutionalize climate awareness within their respective domains. Climate-aware workforce development efforts should train individuals for work in installing, maintaining, and repairing renewable infrastructure. The utility should continue long-term monitoring of system operation under climate change to plan implementation of climate-related enhancements. If the life of assets begins to change to an extent that exceeds minimum operational requirements, alternative technologies that better align with Puerto Rico's financial and operational requirements may need to be evaluated. Maintaining ongoing monitoring and evaluation, as well as partnerships with other U.S. utilities with similar operational and climate profiles, may help provide early warning. With respect to the implementation of climate-related enhancements, climate data should be made available to planners, researchers, community organizers, and activists for climate-aware energy planning. As a start, this includes making the climate-related findings of PR100 widely available and understood (Section 13, page 507).

Explore potential for controlled EV charging to support grid.

PR100 performed projections for EV adoption through 2050 for light-, medium-, and heavy-duty EVs (Section 5.3, page 138). Though the projections are highly uncertain, the increased adoption of EVs may provide the opportunity to control EV charging to take advantage of periods with high generation and to avoid adding additional stress to the grid during peak load times. There may be possibilities for forming vehicle-to-grid programs. While vehicle-to-grid programs were not explicitly studied in PR100, it is suggested that stakeholders explore the potential for such programs to support long-term goals (CEC n.d.; SDGE n.d.). Vehicle-to-grid programs would include controlled charging but would additionally allow EVs during periods of high-demand—afternoon and evening—to provide energy back to the grid to support operation. Benefits of such programs may include reduced costs for the grid operators, the use of EVs to provide resilience during outages, and stability of the grid during events with tight margins. However, significant infrastructure upgrades, namely the controls and communications of the distribution system, are required to enable the adoption of such vehicle-to-grid programs and will be costly to implement. Also, limitations exist with the use of the EV battery to support grid interactions; therefore, careful consideration should be taken before adopting such programs.

17.6 Recurring Actions: Continually Maintain the System and Improve Planning Processes

Several considerations and specific actions simply do not fit into a specific period, but rather need to be recurring and continuously addressed throughout the entire planning horizon. Throughout the entire planning horizon, focus should be on continually maintaining the system as it evolves and improving planning processes as the system reaches the Act 17 targets. This section identifies and discusses several recurring actions for the stakeholders of Puerto Rico to consider.

17.6.1 Actions Supported by PR100 Findings

Table 79 introduces the recurring action identified by PR100 findings, and discussion of the rationale for these actions follows the table.

Table 79. Recurring Actions Identified by PR100

Action	Action Areas	Stakeholders
Evaluate capital costs, forecasts, and emerging technologies as they mature to diversify energy mix at the least-cost options.		✓ Utility and Grid Operators ✓ Energy Regulators ✓ Renewable Developers
Ensure planning processes include stakeholder engagement to pursue stakeholder-driven pathways for implementation.		✓ Utility and Grid Operators ✓ Energy Regulators ✓ Renewable Developers ✓ Customers and Communities

Action	Action Areas	Stakeholders
Ensure the power system meets acceptable reliability and resilience metrics as the system evolves.		✓ Energy Regulators ✓ Utility and Grid Operators
Continue deployment of rooftop PV and storage and identify microgrid opportunities to support community resilience.		✓ Utility and Grid Operators ✓ Renewable Developers ✓ Customers and Communities
Spread generation across the territory to avoid single point failures.		✓ Utility and Grid Operators ✓ Renewable Developers ✓ Energy Regulators
Install energy storage to mitigate issues in T&D systems.		✓ Utility and Grid Operators ✓ Renewable Developers
Ensure financing and rate recovery decisions weigh rate affordability, energy burden, and utility costs.		✓ Utility and Grid Operators ✓ Energy Regulators ✓ Customers and Communities

17.6.1.1 Rationale for Actions

Evaluate capital costs, forecasts, and emerging technologies as they mature to diversify energy mix at the least-cost options.

Several factors in the grid planning processes are highly uncertain, and they therefore require constant reevaluation to make informed decisions that benefit the ratepayers across multiple planning objectives. Capital costs of candidate technologies can vary from year-to-year based on the current economic situation, and projected costs are often presented with a wide range of outcomes to bookend possible scenarios. Furthermore, forecasts such as those for load, EV adoption, and DERs adoption should be reevaluated on a recurring basis to reflect historical adoption rates as time progresses. Lastly, technologies that have potential to accelerate the energy transition will gain maturity as more systems are deployed. Therefore, constant evaluation of emerging technologies is critical to identify optimal solutions for the stakeholders of Puerto Rico. Careful consideration must be taken when evaluating emerging technologies[220]

[220] To be clear, emerging technologies in this report can refer to proven technologies that are new to the Puerto Rico system.

to ensure the feasibility, operational benefit, and economic impacts of such technologies are in the best interest of the stakeholders.

Ensure planning processes include stakeholder engagement to pursue stakeholder-driven pathways for implementation.

As discussed in Section 2, page 11, stakeholder engagement is a mechanism to inform future investments on the Puerto Rico power system. Involving a breadth of stakeholders to develop and implement meaningful processes for engaging communities, assessing potential impact, and interpreting land use policy can support deployment of large-scale renewable energy projects. Developing processes that foster community and industry sector participation and take into consideration their unique and common perspectives can ensure broad and meaningful stakeholder participation in planning, decision-making, and implementation of Puerto Rico's energy future. Furthermore, identifying local leaders across a wide variety of sectors to lead the implementation and planning efforts and coordinate with the utilities, grid operators, and energy regulators will improve grid planning processes. Overall, this action can help support a just and inclusive energy transition for Puerto Rico and should be a recurring action during the energy transition.

Ensure the power system meets acceptable reliability and resilience metrics as the system evolves.

A key consideration is to ensure the energy system meets acceptable reliability metrics as the rollout of renewables continues from the near term. Reliability metrics can include the system average interruption duration index (SAIDI), which is a metric that reflects the minutes per year in which the system experiences an outage. In 2021, the U.S. median SAIDI was 136, compared with Puerto Rico's SAIDI score of 1,559. The median SAIDI score for Puerto Rico's energy system should be brought in line with the U.S. median. Additionally, the system average interruption frequency index (SAIFI) of 7.8 for Puerto Rico should be brought down to the U.S. median level, which was 1.1 in 2021 (FOMB 2023b).

While there are no mandated standards in the United States, it is suggested to leverage the reliability criteria laid out by the North American Electric Reliability Corporation (NERC)[221] and the IEEE to develop the desired system performance (IEEE n.d., 1366–2022; Teixeira 2019). The NERC Reliability Standards and IEEE standards are industry-driven and are developed to balance the interests of stakeholders. Additionally, the system must be hardened by establishing requirements for infrastructure to withstand threats. Furthermore, efficient recovery and restoration measures must be established in Puerto Rico in the event of a threat that causes major disruptions to the delivery of power to the customers. Implementations to improve energy system resilience include identification of both critical loads and significant noncritical loads and solutions designed to disconnect those loads during black-sky events. In doing so, the outage impacts will be dampened, and recovery efforts will be expedited.

Acceptable reliability metrics are not currently clearly defined: it is critical for the stakeholders of Puerto Rico to agree on the acceptable performance levels for reliability metrics throughout the entire planning horizon. LUMA reports performance metrics to PREB quarterly to track progress in rebuilding the system to an acceptable performance level (LUMA 2023a).

[221] "Standards," NERC, https://www.nerc.com/pa/Stand/Pages/default.aspx

Continuously measuring and reporting such metrics will contribute significantly to achieving the desired resilience and reliability of the system. Resilience and reliability goals should be clearly defined by the stakeholders of Puerto Rico. For PR100, stakeholders identified this action as a key goal that should be revisited frequently as the system evolves. Stakeholders of the Puerto Rico energy system should work together to clearly define resilience and reliability goals while also considering other planning objectives, such as economic impacts to ratepayers, Act 17 goals, and equitable implementation solutions.

Continue deployment of rooftop PV and storage and identify microgrid opportunities to support community resilience.

PR100 identified a wide range of rooftop PV adoption via scenarios that explored the economic, equitable, and maximum adoption of the rooftop PV and storage by the customers (Table 22, page 178). Engagement with stakeholders showed a recurring theme of preference to distributed solar resources to mitigate the effects of long, sustained outages. Regardless of the scenario outcomes, PR100 identified opportunities over the next few decades to continue the deployment of rooftop PV and storage and identify microgrid opportunities to support resilient and reliable operations (Jeffers et al. 2018; Broderick et al. 2022; Newlun et al. 2020). However, careful consideration needs to be taken when deploying large amounts of DERs regarding the impacts on the distribution system and substations and the need for advanced metering infrastructure to support accurate billing and compensation.

Spread generation across the territory to avoid single point failures.

Spreading generation across the territory to avoid single point failures (see Section 10, page 267) should remain a key consideration across all periods. PR100 identified the benefits of smaller utility-scale generation when they are spread out across the territory: additional generators spread across more locations perform better than fewer, larger generators, and this can also help with voltage control across the system at the T&D levels. Spreading generation will also improve the recovery process after extreme meteorological events and other threats.

Install energy storage to mitigate issues in T&D systems.

Implementing energy storage would improve system reliability immediately, even before more renewables are connected. While this action is specially discussed in the near term for both utility-scale and distributed storage, energy storage installation may be an action that spans all periods of the Roadmap. Given the significant extent of renewable technologies and the need to meet reliability, resilience, and recovery goals, energy will play a critical role in the future. For instance, significant levels of battery storage may be among the best options to mitigate both overvoltage and reverse power flow issues. Assuming an adequate compensation scheme is devised, high levels of customer-owned storage may help the grid. Customer-owned storage may also bring significant direct cost savings to the utility, as it could reduce the amount of utility-owned storage that may be required. Early installation of energy storage, at the utility and distributed scales, would allow planners and operators in Puerto Rico to gain experience with the technology, which could provide the additional benefit of being able to solve current operational challenges with frequency control and system reliability. Additionally, installing storage systems with advanced controls, such as GFM controls, fast-frequency response, voltage control, and connection to automatic generation control, can be implemented to strengthen the grid and provide black-start capabilities. Larger utility-scale storage systems can provide day-to-day discharges to mitigate shortfalls in the system, while distributed storage systems, when coupled with adequate generating resources, can meet demand during grid outages.

Ensure financing and rate recovery decisions weigh rate affordability, energy burden, and utility costs.

A goal of the energy transition is that the most economically disadvantaged customers are not left disproportionately burdened by the investments made in Puerto Rico's grid modernization and energy transition. Implemented redesigned retail rates would help ensure affordability for customers and maintain a healthy utility. Redesigned rates should cover the types of costs incurred using charges to sufficiently recover those costs. Expansion of financial assistance programs may be needed to help offset the impacts to all households. Additional retail rate discounts may be needed for lower-income customers to mitigate the impacts of higher rates.

Additionally, there is a need to simultaneously identify and pursue opportunities to reduce utility capital and fixed costs and increase electricity sales while paying particular attention to price structures for disadvantaged communities. These efforts should better align the total costs of the system upgrades with the utility revenue requirements. This effort will require long-term integrated planning efforts that consider all opportunities to reduce integration costs of increasingly greater levels of renewables. These considerations should be revisited periodically throughout the planning horizon.

17.6.2 Additional Considerations

Table 80 provides the recurring actions the PR100 project team took that were determined to be considered best practices that are indirectly related to the findings of PR100 and were identified by subject matter experts and through stakeholder engagement.

Table 80. Recurring Actions Identified as Best Practices

Action	Action Areas	Stakeholders
Facilitate a stable, local workforce to support installation, operation, and maintenance of the system across the entire planning horizon.		✓ Utility and Grid Operators ✓ Energy Regulators ✓ Renewable Developers ✓ Customers and Communities
Improve planning processes to adapt to evolving threat landscape and coordinate with interdependent infrastructure systems.		✓ Utility and Grid Operators ✓ Energy Regulators ✓ Renewable Developers ✓ Customers and Communities

Action	Action Areas	Stakeholders
Coordinate generation, transmission, and distribution investments under competing objectives.		✓ Utility and Grid Operators ✓ Energy Regulators ✓ Renewable Developers ✓ Customers and Communities

Resource & Demand-Side Management Deployment
Grid Upgrades, Operations, & Maintenance
System Resilience, Reliability, & Recovery
Community Resilience, Climate, & Energy Justice
Economic & Workforce Development

17.6.2.1 Rationale for Actions

Facilitate a stable, local workforce to support installation, operation, and maintenance of the system across the entire planning horizon.

As noted, in the near term, significant labor will be needed to jumpstart renewables development in Puerto Rico. Developing and expanding job training and education programs will help prepare the Puerto Rico workforce to meet the estimated 25,000 jobs required for the transition to 100% renewables (Section 12, page 401). Supporting workforce training within Puerto Rico has benefits for household and territory-wide economics, and for public knowledge and participation in energy system development. In the near term and the mid term, it will be important to retain this workforce to provide stability and to enable the ramp-up in labor needed in the long term for the last push of renewable installations needed to achieve 100% renewables. The labor should be sourced locally to ensure financial benefits remain in Puerto Rico. While outsourced labor could fill gaps temporarily, obstacles such as migration and temporary housing could be avoided with a local workforce. Efforts to develop occupational training programs should aim to support and encourage sustainable employment opportunities. By comparison, growth for operation and maintenance fields tends to be more stable, allowing for more time to grow a sustainable workforce in those areas. There will likely be a stable growth in the operation and maintenance jobs needed to operate a highly complex system as the system approaches 100% renewables. This need also provides an opportunity to continue the development of effective and efficient job training programs to create a sustainable local workforce for years to come.

Improve planning processes to adapt to evolving threat landscape and coordinate with interdependent infrastructure systems.

As the threat landscape evolves and climate data become more readily available, grid planning practices and disaster plans must adapt and continually improve so that stakeholders can make well-informed investment decisions and carry out emergency response operations. Because of climate change, the severity of threats and consequent impacts to the energy system could change significantly over the next few decades. Therefore, a wide range of stakeholders must adapt the disaster recovery plans to ensure efficient recovery from such disasters. It is also important for grid planning processes to coordinate with other interdependent infrastructure systems, as discussed in Section 14 (page 539). Operators of energy-dependent infrastructure, such as communications, transportation systems, and food and agriculture, should have similar studies to PR100 conducted for their systems to account for shifting needs and emerging challenges (e.g., climate risks) that might disrupt their operations and require joint efforts with energy infrastructure operators. Previously identified interdependencies should be regularly reviewed and updated as needed. Energy planners should coordinate with the operators of energy-dependent infrastructure to develop a broader understanding of the electricity dependency landscape—at both the utility and local community levels—and to facilitate regular joint efforts in bolstering the resilience of these energy-dependent systems. This can be put into practice through regular meetings of electric utilities and operators, and other dependent infrastructure utilities and operators to discuss concerns about reliability and resilience. Regular operation and maintenance investments should be implemented accordingly. Finally, to continue hardening infrastructure interdependencies, planning and construction of new capital projects—both in the energy sector and its dependent infrastructures—should be planned based on critical nodes, equitable access, and historical and predicted threat impacts.

Coordinate generation, transmission, and distribution investments under competing objectives. As new resources are deployed and existing resources are retired, significant T&D systems upgrades will be required to support the high-renewables system. These upgrades can be costly and require significant lead times. Therefore, continual coordination of all grid upgrades, including both T&D upgrades, alongside new resource siting must occur. If this is done, economic solutions will be implemented in a timely manner and will ensure the customers receive several benefits from the proposed solutions. Additionally, to reduce the need to significantly enhance the transmission network, resources should be distributed across the territory (as highlighted in PR100 key findings, Section 8, page 209, and Section 9, page 241). This recurring action consists of considerable upgrades to the modeling tools and planning processes that are used today. Failure to coordinate investments of the T&D systems with resource expansion can result in costly expansion plans (Spyrou et al. 2017). Therefore, stakeholders should continually coordinate investments at all levels to ensure the most cost-effective solutions are identified and the resilience, reliability, and equity goals are achieved. Furthermore, resources should be economically deployed so the utility and customers see economic benefits while ensuring the resilience, reliability, and energy justice needs are met throughout all Roadmap periods. Lastly, there is a need to assess and quantify the benefits related to renewable generation that do not have monetary value, including environmental, resiliency, reliability, and health benefits. This may require modifying planning processes and associated models to incorporate competing objectives, such as cost, reliability, resilience, equity, and meeting policy goals. Namely, the stakeholders in Puerto Rico and the research community should work toward more efficient coordination of investments at all levels of the grid.

17.7 Conclusion

The PR100 Implementation Roadmap provides actionable pathways for the stakeholders of Puerto Rico to transition from the current state to the desired target state, where the goals of Act 17 are met while ensuring the grid is robust, reliable, resilient, economic, and promotes energy justice. The Roadmap leverages the technical findings of PR100 and the insights gained through stakeholder engagement and best practices.

Overall, the key goals of the Roadmap were to identify actions stakeholders can consider in the immediate, near term, mid term, and long term. These actions were mapped to a broad range of action areas and stakeholder groups to further promote the implementations required to achieve the target state of the Puerto Rico energy system. The Roadmap is intended to provide a set of actions for the stakeholders of Puerto Rico to consider to both meet milestones of the territory's energy transition and provide implementation actions that can be leveraged to make informed decisions for decades to come.

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Glossary

Act 17	The Puerto Rico Energy Public Policy Act (Act 17), passed in 2019, set a goal for the territory to transition away from imported fossil fuels and instead meet its electricity needs with 100% renewable energy by 2050, 60% by 2040, and 40% by 2025.
Bus	“An electrical conductor that serves as a common connection for two or more electrical circuits” (EIA, n.d.-a)
Capacity expansion modeling	“Capacity expansion modeling simulates and optimizes generation and transmission capacity costs given assumptions about future electricity demand, fuel prices, technology cost and performance, and policy and regulation.”(NREL, n.d.-a).
Capacity factor	“The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period” (EIA, n.d.-a).
Cooling degree days	Degree days are the difference between the daily temperature mean and 65°F, the outside temperature when no heating or cooling is needed for comfort. Cooling degree days (CDD) measure how hot the temperature was on a given day or days.
Diurnal storage	Energy storage that has a duration such that it can be charged and discharged during a single day: typically 0–10 hours of duration
Electric load	An end-use device or customer that receives power from the electric system
Electricity consumption	The amount of electricity used over a certain time, measured in kilowatt-hours (kWh)
Electricity demand	“The rate at which energy is delivered to loads and scheduling points by generation, transmission, and distribution facilities,” measured in kilowatts (kW) (EIA, n.d.-a)
Feasible scenario	A scenario by which Puerto Rico can reach 100% renewable energy by 2050 that is helpful to the ongoing conversation about the future and for which economic or engineering reasons to discount the scenario are not possible or known
Integrated resource plan	An assessment of the future electric needs and plan to meet those needs. Assesses the demand-side (e.g., conservation and energy efficiency) and supply-side (e.g., generation/power plants and transmission lines) resources in making recommendations on how best to meet future electric energy needs
Last-mile community	A census block that (a) has a high percentage of very low-income households, and (b) experiences frequent and prolonged power outages. (DOE GDO 2023)

Levelized cost of electricity (or energy)	A measure of the average net present cost of electricity generation for a generator over its lifetime: It is used for investment planning and to compare different methods of electricity generation on a consistent basis.
Long-duration storage	Electrical energy storage with more than 10 hours of discharge duration at rated power (Denholm et al. 2021)
Municipality	Puerto Rico is administratively divided into 78 municipalities, also known as municipios, as the secondary unit of administration following the central government. Each municipality has its own mayor and local government office. For U.S. Census purposes, municipalities are considered county equivalents.
Puerto Rico Energy Recovery and Resilience Advisory Group (Advisory Group)	An advisory group convened by NREL to inform DOE's portfolio of support for Puerto Rico energy recovery and resilience, including PR100, responsive technical assistance engagements, and other related activities
Resilience	"The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions to the power sector through adaptable and holistic planning and technical solutions" (Stout et al. 2019)
Resource adequacy (RA)	A regulatory construct developed to ensure that the power system has enough resources to meet electric demands under all reasonably likely conditions
Renewable portfolio standard	A regulatory mandate to increase production of energy from renewable sources such as wind, solar, biomass, and other alternatives to fossil and nuclear electric generation; also known as a renewable electricity standard
Task	In PR100, the term "task" refers to a discreet section of work on a specific topic within the study. The study was organized into 11 tasks (Figure 2), each of which was led by one of the contributing national laboratories. Many of the tasks included contributors from multiple labs, and the tasks were interconnected. The outputs of some tasks were the inputs to others in the modeling tool chain.
Topology	Power system topology is defined by the connectivity among power system components, such as generators, power transformers, transmission lines, and loads.
Tranche	In PR100, we primarily use the term tranche to refer to rounds of procurement in 2019 IRP implementation.

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Appendix A. Executive Summary

A.1 Scenarios and Variations Modeled in PR100

Table A-1. Scenarios and Variations Modeled in PR100

Scenario Number	Scenario Short Name	Variation 1: Land Use	Variation 2: Electric Load	Scenario Identifier
1	Economic	Less	Mid	1LM
1	Economic	Less	Stress	1LS
1	Economic	More	Mid	1MM
1	Economic	More	Stress	1MS
2	Equitable	Less	Mid	2LM
2	Equitable	Less	Stress	2LS
2	Equitable	More	Mid	2MM
2	Equitable	More	Stress	2MS
3	Maximum	Less	Mid	3LM
3	Maximum	Less	Stress	3LS
3	Maximum	More	Mid	3MM
3	Maximum	More	Stress	3MS

A.2 Assumptions and Constraints

Following are a few assumptions made in PR100. Additional assumptions that underpin specific analyses are discussed in the relevant sections of the full report.

- All modeling and analysis in PR100 assume compliance with Puerto Rico energy policy, including Act 17; the definitions of renewable energy assumed are in the:
    - Public Policy on Energy Diversification by Means of Sustainable and Alternative Renewable Energy in Puerto Rico Act (Act 82 of 2010, as amended) (Puerto Rico Legislative Assembly 2010)
    - Puerto Rico Climate Change Mitigation, Adaptation, and Resilience Act (Act 33 of 2019) (Puerto Rico Legislative Assembly 2019b, 33–2019)
    - Puerto Rico Electric Power Authority's (PREPA's) 2019 integrated resource plan (IRP) (Siemens Industry 2019; PREB 2020).
- In the modeling, we include only generation technologies that meet the definition of renewable energy in the aforementioned public policy. Consistent with Act 82 as amended, technologies considered in PR100 include solar energy, wind energy, hydropower, marine and hydrokinetic renewable energy, ocean thermal energy, and combustion of biofuel derived solely from renewable biomass. Of the other resources listed in Act 82, we do not include geothermal energy, renewable biomass combustion, or renewable biomass gas combustion.

- The retirement schedule for existing fossil-fueled generation units follows the retirements established in the 2019 IRP (Siemens Industry 2019; PREB 2020). Note that PREPA has stated that the planned retirements from the 2019 IRP are based on assumptions regarding renewable technology cost and electric load reductions and that the new renewable energy generation (with compliance with minimum technical requirements) is also assumed; therefore, retirements might change because those assumptions are not maintained on schedule.
- Transmission is identically represented in all 12 scenario variations using a linearized DC power flow model to represent lossless active power flow in the network. The production cost model is configured to enforce flow limits on lines rated at 115 kV and above, whereas flow limits are relaxed on 38-kV lines because of the uncertainties associated with specific renewable interconnection points and demand changes, so 38-kV overloads are expected.

A.3 How to Access Solar and Wind Resource Data

Solar Resource Data Sets

Users can access the solar resource data sets via the National Renewable Energy Laboratory's National Solar Radiation Database (NSRDB) website in three ways: the NSRDB Viewer, an application programming interface, or a cloud-based service.[222]

Wind Resource Data Sets

Twenty years of wind resource data (5-min and hourly temporal resolutions) are available on the Highly Scalable Data Service (HSDS). Users can refer to a GitHub repository with setup guidance for using a Jupyter notebook to access the HSDS data.[223] Users need to clone the repository to their computers and follow the instructions starting at "How to Use." Once users get a sample notebook to work with an HSDS data set, they can modify it to work with their own data set. If users install h5pyd[224] and execute hsconfigure, they should be able to test the connection by running the hsinfo. Then, users can check the /nrel/directory by executing hsls. For example, users can run hsls /nrel/ to see what is in the directory.

The wind data sets for Puerto Rico are in:

1. Hourly data (puerto_rico_wind_hourly_yyyy.h5): /nrel/wtk/pr100/hourly/

2. 5-min data (puerto_rico_wind_5min_yyyy.h5): /nrel/wtk/pr100/5min/.

[222] See "How to Access the Data," NREL, https://nsrdb.nrel.gov/data-sets/how-to-access-data.
[223] https://github.com/NREL/hsds-examples
[224] As shown in the instructions available at https://github.com/NREL/hsds-examples

Appendix B. Stakeholder Input

B.1 Advisory Group Input from Year 1

Table B-1. Advisory Group Member Input from Year 1 and How it Was Incorporated into PR100[225]

Topic	Advisory Group Member Input	How Incorporated
Priorities for Puerto Rico's Energy Future	• **Reliability of Electricity Supply:** balanced, reliable, and sustainable generation mix; hardened transmission and distribution network that will sustain communities during major events without increasing energy injustice; on-grid operations including protection and voltage regulation • **Resilience:** All-hazards resilience; ensuring residents have equitable access to critical services during regular grid operations and emergency situations • **Decentralization of Supply/Distributed Energy Resources:** Rooftop solar and storage; microgrids; community ownership models of community solar • **Affordability/Cost-Effective Solutions:** Reasonable cost and cost stability throughout transition to renewables; reduce energy burden (price paid for energy as percentage of income); energy efficiency • **Energy Justice/Social Justice:** Community ownership of energy assets; community participation; inclusion of low- and moderate-income customers; energy democracy; energy independence; equitable access; workforce development on in Puerto Rico; saving lives • **Transition to Renewable Energy:** diversify renewable portfolio; energy transformation based on local resources • **Land Use and Environmental Impacts:** Preserve/protect agricultural and ecological land and natural resources; agrivoltaics and other colocation solutions; efficient land use, vertical farming; sustainable material management for new technology; recycling of solar panels; circular economy for renewable generation	Breakout group discussions on this topic in our March meeting informed the project team's initial approach to scenario definitions.
Energy Justice	• **Energy Access, Affordability, Reliability, and Resilience:** Ensure equitable access to affordable, reliable, resilient, renewable energy for all households and businesses, including underserved and rural communities (those not in middle or upper class); ensure cost of energy is not a financial burden • **Community Participation:** Ensure the study incorporates local knowledge, and results are shared in a way that everyone can understand them; recognize	Energy justice priorities further informed scenario definition.

[225] A member of the Advisory Group suggested this table of detailed Advisory Group member input could be used as framework to identify spheres of concern and responsibility (e.g., legal, financial, and management) and prompt future group discussions and stakeholder engagement towards specific actions to address the issues identified.

Topic	Advisory Group Member Input	How Incorporated
	and include underrepresented Puerto Ricans and communities in the decision-making processes • **Economic and Workforce Development:** Energy transition designed to drive economic development; a just transition moves our economy off of fossil fuels and toward clean solar energy in Puerto Rico, while providing just pathways for workers to transition to high-quality work • **Siting, Land Use, Environmental and Health Effects:** Use the existing built environment footprint first and foremost; ensure the energy transition does not negatively affect the development of other essential services like food production; consider appropriate balance of land use (e.g., not sacrificing agricultural land for energy development) • **Public Sector Implementation:** Greater transparency around use of federal funds and timing; access to funds by municipalities and others for local resiliency projects; ensure PREPA and LUMA take into account PR100 results and input from local energy experts regarding contracting and selection process for federal funds • **Engagement with Communities to Learn How They Define Energy Justice**	
Scenario Definition	• **Equitable Access:** Include low- and moderate-income communities in all scenarios; consider how providing back-stop financing to remote, vulnerable, and low- and moderate-income families with subpar credit would change the pool size of residential solar and storage customers • **Model Complexity:** Integrate complexity beyond techno-economic considerations, such as time, governance, social acceptance, gender, socioeconomic status, and other social variables • **Clarification of What Is Meant by Critical Services:** Government or privately owned facilities (e.g., hospitals), bakery/food supply, and other services; reconsider the need to define critical facilities based on the limitations of the centralized generation scheme • **Land Use:** Agricultural reserves have been established by law; that land has been set aside solely for agricultural use • **Reliability and Resilience:** Consider the cost of not having a resilient system, of restoring after natural disasters, of rebuilding infrastructure for distributed versus centralized cases; establish a baseline level of reliability and resilience to be achieved across all scenarios; utilize metrics like system average interruption duration index (SAIDI)/system average interruption frequency index (SAIFI) and customer	Some of these additional comments related to scenario definition certainly informed our thinking.

Topic	Advisory Group Member Input	How Incorporated
	hours of lost electric service; consider/quantify reliability at the household level • **Economics:** Challenges to assumption that Scenario 1 is the least-costly and Scenario 4 the most; rooftop solar and small microgrids are more efficient than a transmission system with high losses and centralized backup generation; what fuel cost (including natural gas) is being used for the modeling, and does it include the predicted higher costs associated with wars, inflation, and transportation/supply issues • **Generation:** Virtual powers plants are super-low-hanging fruit; rapid deployment of large-scale solar and storage levels of megawatts is an essential action to quickly turn off the coal plant • **Timing:** The speed of the proposed transition from fossil to renewable sources makes attractive large utility-scale projects, and those projects will collide with land requirements and public interest or expectations that more percentage of DERs should be implemented instead • **Study Results:** Show year-by-year adoption of technology for scenarios; what priorities will be compared across scenarios: Saving lives? Recovery time after disasters?	
Land use and exclusions	• **Food Security:** Food security should be considered from the point of view of the overall impact of using agricultural land for energy generation rather than food production; more than 85% of food in Puerto Rico is imported. We are trying to lower our reliance on importation by producing more food; some comments in support of agrivoltaics; it is a false choice to pit renewables versus general sustainability, including food security • **Land Use Planning:** Agricultural reserves have been established by law; that land has been set aside solely for agricultural use • **Favorable Locations for Development:** Prioritize rooftops (commercial and industrial, school buildings), parking lots, brownfield sites, former industrial sites, contaminated sites, closed landfills, nonagricultural land owned by the pharmaceutical industry; 13% of all of Puerto Rico is already urbanized, use this for distributed renewable • **Timing and Resilience:** Consider both location and timing of utility-scale deployment. Prioritize rooftops first from a resilience perspective because large-scale systems depend on the grid • **Social Acceptance:** Consider approval of surrounding communities if doing large farms	Input about land use informed the two land use variations in the study, including one that does not allow renewable energy to be developed on agricultural land.

Topic	Advisory Group Member Input	How Incorporated
	• **Data Sources:** Contact the Puerto Rico Conservation Trust (Para La Naturaleza) to supplement Protected Land Areas info; several GIS data sets on soil data for land not suited for agriculture	
Technology Cost	• Residential solar and storage cost estimate of \$27,000–\$30,000, with around \$14,000 for the storage component • Costs vary from \$3.75/W to \$6/W for solar and storage; concerns about long-term contracts that have been given at \$9/kWh–\$12/kWh so developers need to compete in a shorter term because these costs will change dramatically • Costs vary day to day; lots of uncertainty with utility-scale solar because no one knows what will happen with rooftop solar • Minimum technical requirements make costs higher, such as having 50% of your capacity in storage • **User Profile Shifts:** Consider how user profiles across sectors and peak demand may have shifted post-pandemic with more people working from the home • **Data Sources:** Commercial banks and cooperatives that have financed solar photovoltaic PV projects in the past; inventory of post-Hurricane Irma/Maria and earthquake damages (e.g., buildings/homes/areas that survived disasters); local retailers of PV equipment (e.g., Glenn International PR); Apoyo Energético price comparison	Input on technology cost informs our modeling.
Resilience (transmission, distribution, social burden)	• In social burden analysis, consider not only distance but also time (rural roads versus city roads) and likelihood that access will be impaired during crises (blocked roads, landslides) • Take different housing contexts into account (e.g., single-family residences, multistory condominiums, rural isolated communities, and densely urban areas) • Appreciate a focus on community resilience; what needs to be resilient is the community, not “the grid” or “the system” • Describe mechanism to determine specific local rural and isolated community needs, especially on islands and mountain communities	
Economic Impact	• Consider the capacity of local universities to generate potential employees • When aggregating economic data into 6–8 regions of Puerto Rico, include a central, landlocked region and take care to represent the center of the main island well • Vieques and Culebra may need a subdivision to include their complex particularities technically and socioeconomically	The economic impact team has taken this input into account for their modeling and how they will report results.

Topic	Advisory Group Member Input	How Incorporated
	• Census data will need calibration because locally the data do not represent the reality due to lack of participation and data gaps	
Misc.	• Every single decision about the energy system becomes politically charged and subject to political forces. Important to consider the likelihood of implementation. Integrate rigorous political analysis, drawing on local expertise in this area. • If the aim is to model population decrease or growth to establish electric load, incorporate sociologists, planners, demographers in our group • Would like to see larger PV systems on the distribution grid (several megawatts) but smaller than utility-scale (PREPA/LUMA in Tranches 1 and 2 did not allow multimegawatt plants on the distribution system) • Consider reliability/resiliency of centralized versus distributed energy to cover Puerto Rico Aqueduct and Sewer Authority requirements to provide water during natural catastrophes • Interest in guidance on what utility data should be made publicly available because it provides a public benefit; would like information to be publicly available and tools open-sourced as the 2050 answer will not be solved in 2 years • Interest in illustrative story maps (Esri/geographic information systems) that can demonstrate overlays of health/social vulnerability data (e.g., income disparity and unemployment) to convey priorities, key metrics, and progress with the aim to engage and inform the public in Puerto Rico • Provide a glossary of the many acronyms used during presentations and sharing of information • Suggestion for DOE to do a road show and discuss the value of the transmission and distribution system to address resilience	The project team is carefully considering this input and will continue to follow up in Year 2 of the study.

B.2 Advisory Group Input from Year 2

Table B-2. Summary of Advisory Group Member Input Received in Year 2 and How It Was Incorporated

Topic	Advisory Group Member Input	How Incorporated
Stakeholder engagement	• Broaden stakeholder representation in the Advisory Group. • Bring more industrial customers, including representatives of the pharmaceutical industry, into the conversation. • Conduct more outreach to industries, entrepreneurs, local companies. • Education is important for DERs. Involve universities and Department of Education in addition to existing university partnerships.	• Added Advisory Group members in Year 2, including industrial sector representatives. • Held a roundtable conversation with the commercial and industrial sector in March 2023.
Energy justice	• Implementation activities related to PR100 are already happening without considering environmental justice and resilience metrics. • Timing is it too late if PREPA and LUMA are already spending FEMA funds. • The Municipality of Salinas is being targeted as a sacrifice zone to site the two largest utility-scale renewable energy projects in Tranche 1. • Consider the correlation between social acceptance and consumer adoption. • Define key terms related to energy justice pillars such as "past harms." • Include in the final report discussion of how energy justice principles exemplified by PR100, particularly procedural and recognition justice and energy democracy, can be incorporated during the implementation process.	• This report includes a description of what we did to integrate energy justice, and what others can do in the future (see Section 3.2, page 41) • We use the term "past harm" consistently with how it is used in the energy justice literature (Climate Justice Alliance, n.d.; Baker, DeVar, and Prakash 2019) to mean "prior harm" or historical harm." The term in this context is not intended to have a specific legal meaning.
Scenarios	• Align Scenario 4 (maximum adoption of DERs) more closely with the *We Want Sun and We Want More* report (Biaggi, Kunkel, and Rivera 2021) and minimize utility-scale build-out. • Include a scenario with "maximum" deployment of DERs publicly financed with federal funds and evaluate the resulting cost. • Conduct environmental impact analysis for each scenario, proposed technology, project, and pathway.	• We updated Scenario 4 with smaller systems, near-term/faster adoption, and updated inputs.

Topic	Advisory Group Member Input	How Incorporated
	• Achieving the target of 40% renewable energy seems more feasible by 2030 than by the current target of 2025.	• We worked with University of Puerto Rico at Mayagüez (UPRM) and others to evaluate the value of distributed systems and location of key customers. • We present the adoption of PV and storage results in conjunction with the necessary distribution grid (and transmission grid) upgrades.
Resilience	• Distributed solar and storage was proven to be the most resilient option for Puerto Rico after it provided electric service when the grid failed after Hurricane Fiona. • Rooftop solar and storage is the way to avoid loss of life after hurricanes. Put this into numbers in Year 2. • Consider how to leverage community resilience planning and work of Puerto Rico Department of Housing in PR100. Working sessions to review the plan with Salinas are happening soon. • There is interest in seeing Sandia National Laboratories' microgrid analysis.	• Resilience was analyzed in the social burden evaluation (Section 14.2, page 561) and bulk power system impact analysis (Section 10.9, page 335) within the study.
Land use	• Importance of preserving Puerto Rico's agricultural lands, ecologically valuable lands, and green spaces. • Continue to focus on agricultural land definitions. Land use variation maps show no agricultural land in Culebra. • Standard exclusions other than agricultural land (e.g., 5% slope for PV and urban areas, waterbodies) are too restrictive, and removing them could open up other options. • Consider modeling alternate solar installations like roadways, bridges, and parking lots. • Preliminary consideration that, "Rapid deployment of PV and storage projects approved in Tranche 1 would help address the immediate need for additional capacity on the system," contradicts the land use plan and law	• In response to stakeholder feedback about preserving agricultural land, we defined two land use variations for scenario modeling: the More Land and Less Land variations (see Section 6.1.5, page 181). Thus, we produced a set of results that pertain directly to a comparison of scenarios in which renewable energy is not built on agricultural land. • We met with the Puerto Rico Planning Board to review and confirm our land use categories.

Topic	Advisory Group Member Input	How Incorporated
	and fails to acknowledge multiple written and oral comments by different Advisory Group members against siting utility-scale renewable energy projects on agricultural land and ecologically sensitive areas. • 80% of Tranche 1 projects are in areas designated agricultural and threaten to destroy agricultural land and ecologically sensitive areas. • Prioritize renewable energy projects on marginal land and the built environment and protecting open space and agricultural land. • Require cost benefit analyses for utility-scale projects taking ecosystem services into account. • Include in the modeling impacts of vegetation removal and making alterations to land contours for renewable energy development in flood prone areas.	• We are not doing site-level assessments within the PR100 study. NREL's Photovoltaic Stormwater Management Research and Testing (PV-SMaRT) project is developing tools and best practices for stormwater management at ground-mounted PV sites.
Resource assessment	• Ensure analysis of each technology includes cost of lack of resilience in future disasters, long-term maintenance, and externalities, especially for marine ecosystems. • Prioritize renewable energy technologies that maximize energy justice and resiliency to save lives and ensure fair access to all communities in Puerto Rico. Consider resilience and equity implications of offshore wind and hydrogen combustion. • Consider diversity of renewable energy technologies according to Act 82 (Puerto Rico Legislative Assembly 2010), not just solar and wind. Give more attention to hydroelectricity, ocean thermal energy conversion, other marine technologies, and green hydrogen.	• Technology cost in the model included the cost of operation and maintenance over time. • We included renewable energy technologies in the modeling that were commercially available and for which reliable cost data were available.
Electric load projections	• Include medium-duty and heavy-duty vehicles for electrification. • Smart electric vehicle (EV) charging will have minimal impact on the electric grid due to low driving demand (5,000 miles/year) for light-duty vehicles.	• We included medium-duty and heavy-duty vehicles in EV modeling.

Topic	Advisory Group Member Input	How Incorporated
	• With reliable and affordable electricity, electric usage could actually increase rather than decrease. • Treat the Mid case and the Stress case loads equally in analysis (capturing the range in between).	
DER adoption, capacity expansion, and resource adequacy	• Rapid deployment of DERs for household, business, and institutional use is needed to save lives. • Consider benefits to low- to moderate-income consumers of oversizing their solar and storage systems and of installing small (a few megawatts) roof-mounted or ground-mounted solar and storage systems on distribution feeders. • Data gap likely exists in number of non-grid connected renewable systems being installed. How will these data be generated and integrated? • Move beyond the univariate model of considering only price as impacting rate of adoption. • Discuss how costs of resilience and outages are being used by the model, and how wetlands and flooding are considered; minimum technical requirements already being followed may address this. Integrate the minimum technical requirements used by PREPA into the modeling effort, as well as long-term maintenance costs and legal costs, if any. • Better land cost data are available than are currently used by the model; a quarterly industrial report is available. Coordinate with Advisory Group members to get the best data and incorporate them into the modeling. • Incorporate information about renegotiated power purchase agreements for the ≈20 utility-scale projects currently permitting. • Accelerated deployment is constrained by supply chain and workforce.	• We updated: • Several key rooftop PV assumptions (federal investment tax credit) via the Inflation Reduction Act of 2022) • The value of backup power • The adoption rate, based on LUMA interconnection data. • Capital costs used in capacity expansion modeling were adjusted to match the observed costs from Tranche 1 projects, including the minimum technical requirements. • At the time we received the suggestion to use better land cost data it was too late to incorporate it into this study. This could be valuable to explore in future work. • We updated how tranche projects were represented in the model, including cost data, based on information we received from LUMA and PREPA. • We simulated resource adequacy considering maintenance and forced outages to ensure reliable operations.
Bulk power system analysis	• Consider FEMA funding for the grid and allocate a large portion to distribution system upgrades. • Consider impacts on the power system of the transition to high levels of DERs	• We captured the extent possible the immediate plans for grid upgrades in the modeling process. • We were open and eager to incorporate

Topic	Advisory Group Member Input	How Incorporated
	as compared with utility-scale generation. • Prioritize hardening the most important transmission lines. • Democratize the decision-making process rather than having the model take inputs from LUMA alone. • Map colors at the substation level are confusing.	more feedback from the Advisory Group and others on model inputs. • In this study, we considered impacts of high levels of DERs on the system. • We added more granularity to analysis and upgraded the maps.
Economic impact	• Different data about household income is being used across tasks in the study (grouping by area median income in other tasks versus income stratification in Task 10[a]). • Regarding the preliminary finding that net energy metering at the full retail rate results in a cost shift from more-affluent to less-affluent customers, the full retail rate that a net energy metering (NEM) customer receives is actually less than PREPA's fuel cost from the gas plants that PREPA must run to meet the load. The nearly 60,000 NEM customers with a rooftop solar plus storage system are an asset to the grid that helps lower the cost to others, rather than adversely impact them, because they can supply energy to the grid during times of peak demand and provide grid services. • Discuss time-of-use rates with PREB in addition to PREPA and LUMA. • There is concern about the role that PREPA debt plays in PR100 modeling efforts. • Net metering statutory protection ends April 2024. The Financial Oversight and Management Board for Puerto Rico is signaling to PREB to devalue. PR100 is important to the growth of net metering. • California and Hawaii ended NEM when penetration approached 25%, and Puerto Rico is at 4%.	• We harmonized household income categorization across study topics. • We considered modeling an alternative to full NEM to explore how retail rates might be affected in the future if there was no export compensation. This approach would have created a cone of uncertainty in which future NEM compensation would fall. Based on stakeholder feedback and our assessment of the utility of these potential results, we decided not to pursue this analysis through the modeling tool chain.
PR100 final deliverables	• Include a map that connects key insights (short) to analysis that supports it (in sections of the final report) to relevant downloadable models and data used for the analysis. • Include underlying data in PR100 results.	• All open-source tools and data sets that do not include proprietary data will be made publicly available as part of final results from PR100.

Topic	Advisory Group Member Input	How Incorporated
	• Study results will be used to (1) help in planning for utility-scale solar and storage projects and understand where need is greatest and (2) strengthen advocacy efforts to ensure equitable access to energy in most vulnerable communities and save lives; data and visuals will be used in our meetings and conversations around Puerto Rico. • Study results could be used by NEM detractors to fight NEM if DOE concludes NEM is "unsustainable." • PR100 must directly inform federal funding investments to ensure building of the bottom-up, forward-looking grid so that all renewable hosting capacity concerns are erased. • Create physical spaces in locations across Puerto Rico, in collaboration with municipalities and universities, where people including students and young people can go to use the data. • Make sure study findings get to the right people through broad community dissemination.	• We did not complete analysis that would have indicated the sustainability of NEM. • We will disseminate results broadly.

[a] All PR100 tasks are listed in Figure 2, page 5.

B.3 Industry Sector Roundtables Feedback

Table B-3. Feedback from Industry Sector Representatives During Energy Roundtables in 2023

Industry Sector/ Representatives	Select Examples of What We Heard
Philanthropic organizations	• Include in PR100 a road map of federal funds highlighting gaps in project financing and a map of the evolving energy policy landscape. • Provide case studies of how projects can leverage federal funds to monetize the federal investment tax credit. • Provide technical assistance and capacity building to help projects prepare for financing.
Business community	• Industrial clients need reliable, affordable baseload. • It is difficult for local food producers to compete when energy costs are so high and unpredictable. • Parts and equipment are damaged by outages. • Hotels are essential because first responders stay there. • Negative online reviews hinder Puerto Rico's tourism reputation. • It is difficult to compete for new manufacturing businesses to come to Puerto Rico because of permits and energy issues.

Industry Sector/ Representatives	**Select Examples of What We Heard**
Agriculture sector	• Some want to see sensible energy policy that protects farmland. • Farmers need energy to protect production. • A reliable energy system is needed at a fair cost. • Voltage fluctuations damage farm equipment. • Technical assistance is needed to access federal programs. • When power is down, business costs triple, which impacts food security overall. • It takes hundreds of years to build healthy soil; the first option for renewable energy development always needs to be impacted lands. • One farmer encouraged others to be open to agrivoltaics and learning more.
Representatives of people with disabilities	• 21.8% of people in Puerto Rico have disabilities. • Families of people with disabilities are often impoverished because parents become caregivers, and they are not eligible for federal Social Security Disability Insurance in Puerto Rico. • A household needs three generators to have equipment plugged in 24/7, and someone needs to turn them on and off and maintain them. • People with disabilities do not want to risk accidents working with generators themselves, and those in apartments cannot use them at all. • Certain medications, such as insulin, need to be refrigerated. • When the power is out, preexisting conditions are exacerbated. • Deaf people are more affected than others by lack of communications during a power outage.
Workforce development and labor needs	• Developers can form alliances with municipalities in which projects are developed to create local employment. • Understand labor needs for the lifecycle of each renewable energy project to ensure workforce needs are met throughout. • Consult the Interstate Renewable Energy Council's (IREC's) solar census results to inform workforce development initiatives. • Develop an education network, working with Puerto Rico education system, K-12, vocational schools, to address renewable energy workforce needs. • Puerto Rico has more than 10 community colleges with a green energy focus, 12 universities, and a robust association of engineers. All workforce-related stakeholders need to be connected. • Diversity and inclusiveness are important. • There is debate about whether there is a labor shortage or an industry slowdown. • Focus on renewable energy workforce issues in PR100. Bring in the federal and Puerto Rico departments of labor to connect workforce stakeholders.

B.4 Community Engagement Tour Feedback

Table B-4. Community Member Feedback Received During the PR100 Community Engagement Tour Across Puerto Rico in 2023

Topic or Theme	Comments (Communities in Which They Apply)
Unique aspects of the community	• For communities affected by flooding, address the need for community-wide and household flood mitigation along with renewable energy adoption. Electricity, water, and sewer service goes out when the community floods. (Loiza and Coqui) • Households with no title to property, no existing electrical service, structural concerns such as unsuitable roofs or electrical system for residential solar installation (e.g., blue-tarped roofs, metal roofs, homes are still in need of major repairs, and multifamily housing). (all communities) • There are unique logistical challenges (e.g., one transmission line or one treated drinking water pipe) and a high cost of living on Culebra and Vieques. • Residents of Vieques were traumatized by decades of bombing by the U.S. Navy (part of Vieques, while inhabited, was an active ammunitions testing area for 50 years), and there is perceived correlation of military activity and health effects in the community. Also, there is urgency to help the people of Vieques, who do not believe the hospital is coming and have lost trust in politicians. • There is a lack of trust in the government. (many communities)
How the community is impacted by existing electric infrastructure	• Non-Puerto Rico Aqueduct and Sewer Authority community aqueducts rely on electricity to pump water, and they do not work when the power is out. Existing governance systems for aqueducts can be models for community-based solar projects and microgrids. (Orocovis and Adjuntas) • Some residents are concerned about the environmental and health impacts of living near the AES coal plant. (Coqui) • Some residents are concerned about vegetation management because when the wind blows, the power goes out. (Orocovis and Adjuntas) • Some residents have been waiting a long time to have poles repaired or replaced. (many communities)
Vulnerable people and communities to prioritize	Vulnerable populations to prioritize include: • Elderly, bedridden, those with disabilities and health conditions • Low-income households • Communities that have been marginalized for a long time • Those who were last to have power restored after Hurricane Maria and Hurricane Fiona and who are often the last to receive services • Remote areas with narrow roads that wash out in heavy rain, and areas with power lines that are knocked down by trees in strong winds • Communities surrounded by water • Single mothers and their children • Victims of domestic violence • Students, pregnant people, some in the middle class

Topic or Theme	Comments (Communities in Which They Apply)
	• Everyone needs energy and water; hurricanes affect everyone; lack of energy affects everything • Prevent people from dying.
Energy solutions the community would like to see in the future	• Widespread support for distributed rooftop solar and storage (most communities) • To be the first solar island in the Americas (Culebra) • Consideration of low-cost solar and storage installation by community-based organizations using kits, smaller system sizes, and other approaches (Coqui) • Installation of correct system sizes to meet basic needs; Powering central AC is a luxury in emergencies. • Help homeowners to finance rooftop solar systems at low interest rates; Use cooperative credit unions to finance solar projects. • Education of residents on how to use rooftop solar and storage systems during an outage and how to maintain systems • Enough technicians in each community to repair solar systems when they go down, particularly in remote communities and for off-grid systems • Prioritization of solar for schools to support children's mental health and provide a sense of security • Backup power for state and private hospitals • Solar-powered shelters or resilience hubs; solar refrigeration for medications • Cooperatives for each community so they can energize the disadvantaged • Microgrids with storage so communities can have access to power without having to depend on LUMA • Protection of agricultural land and fertile soil (most communities) • One landowner would like solar on his land because the younger generation of his family is not interested in farming. (Orocovis) • Installation of solar on polluted lands near power plants; prioritization of disturbed lands for solar development • Support for solar farms (large ground-mounted systems), backup systems for hospitals, and reliable distribution system in the long term, in addition to rooftop solar to address the near-term need for resilience • Support for ocean thermal energy conversion (Vieques) • Support for undergrounding lines as part of road repairs (Culebra) • Support for hydroelectricity (repair of old hydropower plants), anaerobic digesters, nuclear, renewable energy solutions that do not rely on nonrenewable resources (e.g., lithium for batteries) or generate waste at the end of service life (e.g., solar panels or batteries) • Recycling of solar panels and batteries at the end of service life • Solutions tailored for each community (Casa Pueblo, Queremos Sol are already doing the work.) • More effort from the government to inform people of available programs

Topic or Theme	Comments (Communities in Which They Apply)
	• Transparency and a person in charge of ensuring federal funds get where they need to be • For FEMA to speed up, for the money to reach the people, better communication and coordination across federal agencies
Energy solutions communities would not like to see	• Opposition to ground-mounted or utility-scale solar (many communities) • Opposition to utility-scale wind (Coqui) • Opposition to green hydrogen; seems like a continuation of experimentation on Puerto Rico by a federal government agency (Vieques) • Opposition to lithium batteries and solar panels as not being eco-friendly • A solar tax • Do not do things behind the scenes that people do not know about. • Fraud, abuse, and corruption
Preferred ways for sharing information and engaging with communities in the planning process	• Listen in every community and hold forums. • Social media, local radio, sound cars, and distribution of flyers like the Census does • Consider that many people do not have internet or cell service, and some are illiterate. • Go to homes to share information if needed. Community leaders know who to reach out to. • Work with community leaders and organizations.

Appendix C. Metrics and Evaluation

Table C-1. Results of Advisory Group Meeting Evaluation of Engagement Processes and Impacts

(Likert responses transformed to scores from 0 to 1, with 0 = lowest and 1 = highest)

Category	Description	Oct 2022	Jan 2023	March 2023	May 2023	June 2023	Aug 2023
Communication and Effectiveness	Effective mix of presentation and discussion	0.70	0.88	0.78	0.63	0.68	0.63
	Content is clear and understandable	0.80	0.88	0.83	0.83	0.71	0.52
Involvement, Cohesiveness and Collaboration	Effectiveness for exchange and participation	0.62	1.00	0.88	0.80	0.89	0.64
	Opportunity to ask questions and feedback	0.78	1.00	0.85	0.85	0.64	0.71
Stakeholder Experience and Satisfaction	Previous input was considered	0.62	0.88	0.85	0.65	0.71	0.59
	Content relevant to objectives and project	0.77	1.00	0.86	0.75	0.93	0.66
Monthly Average Across Categories		0.72	0.94	0.84	0.75	0.76	0.63

Appendix D. Theoretical Foundation of Energy Justice in PR100

D.1 Pillars of Energy Justice

Grounding PR100 in practices and principles of energy justice began with involving stakeholders in the study and adhering to practices that define a just process for energy planning. We formed an understanding of energy justice principles by conducting a review of the literature, which points to four primary pillars. Seminal scholarship (Walker and Day 2012; McCauley et al. 2013) categorized three distinct domains of energy justice that can be considered its pillars:

- *Distribution justice* refers to the way the costs and benefits of the energy system are distributed among the people in any way connected to it. The costs and benefits range from basic elements such as the availability of energy and its price to any other outcome of the system, including, for example, pollution from energy generation or economic opportunities arising from the capture of fossil fuels. Another dimension of distribution justice highlighted by Markolf et al. (2022) and Carvalhaes et al. (2020) is the need for equitable approaches to increasing infrastructure resilience for all hazards and treating resilience as a public good.
- *Procedural justice* refers to how decisions are made, and whether this process is equitable. It emphasizes that no outcome could be considered equitable, nor are acceptable outcomes likely, if the processes for making decisions about the energy system are not themselves fair and inclusive. This is generally taken to require, at a minimum, decision-making processes that encourage input from all stakeholders and transparently provide those stakeholders with information about both the energy system and the decision-making process.
- *Recognition justice* focuses on the need to incorporate the views, concepts, and values of multiple stakeholders, and to do so in their own terms. Recognition can be broadly viewed as the incorporation of knowledge learned from sources across the collection of stakeholders, the full consideration of that knowledge, and the acknowledgement that this knowledge is valid. A canonical example from the literature (Walker and Day 2012) is the recognition that elderly homeowners have different energy needs (i.e., warmer homes) than the rest of the population; this counters an initial assumption that all households were effectively equivalent, and shaped the way that energy rates were considered—leading, importantly, to a system of distribution that treated elderly homeowners differently from others, an example of how treatment that is *unequal* can be more *equitable*. Somewhat more deeply, however, recognition justice involves the acceptance by those traditionally empowered to make decisions about the energy system of viewpoints and concerns that come from others. Recognition *injustice* would be the denial of full participation in the energy system to a group that expresses energy needs or concerns that are not of interest to those in power; "[a] lack of recognition can therefore occur as various forms of cultural and political domination, insults, degradation and devaluation" (McCauley et al. 2013, #).

These three pillars are clearly mutually interrelated. Procedural justice—a "fair" process—cannot be truly achieved without incorporating all views and considering them valid (recognition justice); costs and benefits of the energy system (distributive justice) cannot be assessed objectively, but the assessment must depend on the subjective evaluations of the energy system participants (recognition justice). Other intersections exist. Further, each pillar can also be critiqued or expanded. For example, achieving procedural justice might involve gathering input from multiple stakeholders before making a decision, but it might also mean allowing stakeholders to design a range of options from which a selection could be made, or it might even mean allowing stakeholders to veto certain options, grading eventually into a situation of shared power.

The energy justice literature was soon supplemented (Heffron and McCauley 2017) with a concept that became known as the fourth pillar: *restorative justice*. This concept draws inspiration more directly from the environmental justice literature and practice, and it focuses on the fact that many energy systems have been structured in ways that disproportionately distributed their costs and benefits, leading to some communities being harmed by past energy practices. Such harms can be environmental (e.g., pollution), economic (e.g., high rates and excessive energy burdens), or of many other forms. Restorative justice brings into the concept of energy justice the idea that an energy system moving forward should acknowledge these past harms, attempt to remediate them when possible, and ensure they are not repeated. This can have direct implications for the design and operation of an energy system; for example, the costs associated with siting generation facilities in specific neighborhoods might be assessed in view of negative environmental impacts that have historically been imposed on those neighborhoods, and a community that has already been injured might demand that these past harms be remedied and that future costs be borne more equitably.

Restorative justice, like the other pillars, can be extended. Some of the core ideas of restorative justice derive from criminal law, where it was proposed as an alternative to purely punitive approaches (Menkel-Meadow 2007). In this context, the focus is on the relationships between the parties involved; what is being restored is the social relationship between them, so that they again have a basis of trust, and, ideally, the *cause* of the past harm is addressed and eliminated.

More recently, a fifth pillar has been introduced: *transformative justice*. Like restorative justice, transformative justice is motivated by harms that the operation of an energy system caused in the past. However, it differs from restorative justice in its proposed resolution: where restorative justice attempts to repair the social relationship that was damaged by the energy system, transformative justice proposes that the nature of that relationship may have been a factor in causing the harm, and therefore should itself be reorganized. As a notional example, a highly hierarchical power structure that generated past harms may not need to be repaired in the way that restorative justice proposes (i.e., shoring up the hierarchy), but instead may be better *replaced* by a flatter structure in which those previously at the bottom of the hierarchy have a greater voice.

Transformative justice is recent, fluid, and complex. For example, Sovacool et al. (2023) write that, “Transformative energy justice must learn to deprivilege western versions of ethics and justice, so that patriarchal, racist, and colonial legacies are exposed, and knowledge is decolonized and pluralized.” This notional example is typical of the directionality of transformative justice: abstractly, the power structure needs to be reconsidered, and any reconsideration might be considered transformative; however, in practical terms, the problematic starting point is almost always one in which decision-making was done by exclusive groups, and the resolution is greater participation and involvement of all stakeholders. The likelihood of better outcomes and of achieving the other components of energy justice is almost certainly increased by broadening participation, and consequently this is the only kind of “transformation” that needs to be considered.

This interest in broadening participation points toward a final conception of energy justice, one that is not traditionally viewed as a pillar, but that nevertheless provides an important framework for understanding how an energy system may be redesigned: energy democracy. According to this concept—energy democracy—the energy system writ large is one in which participants are deeply engaged and directly involved in all aspects of the system and collectively shape the system's structure, operation, and outcomes.

In sum, these five pillars of energy justice (Figure 10, page 41) offer us a foundation for, and a vision of, an energy system in which costs and benefits are equitably distributed, distinctive needs and subjective valuations of specific groups are recognized and accommodated, past harms are remedied and not repeated, and decisions about the energy system are made through a participatory process in which an engaged citizenry are actively involved.

D.2 The Place of PR100 in the Energy Justice Context in Puerto Rico

The principles of energy justice provide a framework within which to consider the place of PR100 in the context of the energy justice issues as they exist in Puerto Rico. The role of the national laboratories is limited; policy decisions are outside the laboratories' purview, and hence PR100 cannot provide specific policy recommendations. But we note three broad categories related to energy justice in which PR100 plays a specific role.

1. The first is in the *inventory and design of metrics of energy justice*. A traditional metric is energy burden: the percentage of a household's income spent on energy. A wider metric, designed by Sandia National Laboratories and discussed in Section 14.2 (page 561), is a "social burden," which asks how difficult it is for a household to replace services that are lost when an area loses power. Our engagement with University of Puerto Rico at Mayagüez has been especially fruitful in understanding the need to customize metrics for the Puerto Rico context; this is discussed in Section 2.2.2 (page 29). Apropos of the role of the national laboratories, it is not appropriate for PR100 to consider one metric more important than another; however, collecting possible metrics, designing new ones (with stakeholder input), and providing data and analytical support for assessing those metrics represent a point where the national laboratories' expertise can be brought to bear.
2. The second category is the recognition that *PR100, although in one sense a project that studies the current energy system in Puerto Rico, is itself not fully separate from that system*; that is, PR100 is involved in, and thus a part of, the energy system. There is therefore a need for the project to act in accord with the principles of energy justice. The PR100 project was conducted with an eye to procedural justice by ensuring voices of all stakeholders were heard and they were offered an opportunity to meaningfully participate. Recognition justice compelled the project to actively seek local knowledge, and to listen, respect, and acknowledge different points of view and divergent evaluations of the energy system. The concepts of restorative justice provided a framework for understanding history of energy in Puerto Rico, and the future implications of this for the challenges of transitioning to renewable energy, as well as for understanding how the PR100 project sits within the social landscape created by these challenges. Distributive justice entered primarily in the evaluation of the scenarios that PR100 designs and presents—that is, each scenario carried different implications for costs and benefits of the future energy system—but the project team was also aware that participation in PR100

was itself a benefit, and that it carried potential costs (e.g., time spent and information shared) for the members of the PR100 Steering Committee and the Advisory Group, as well as the public at large, and that these costs and benefits should be distributed equitably.

3. Finally, *PR100 embraced transformative justice by recognizing the project plays a role in laying a foundation for the participatory energy system* that lies in Puerto Rico's future. The heavy emphasis on providing data and tools that will be available beyond PR100 is driven by this: the discussions about Puerto Rico's energy future will go on beyond PR100, but the project was intended to provide a robust distillation of the national laboratories' expertise and analysis to help inform that discussion. This intention impacted everything from scenario design—which scenarios best inform these discussions—to the design of a website with data visualizations, and motivated PR100 to ensure the appropriate information and, when applicable, the software needed to analyze that information, was made available as widely as possible. It also reflects an additional implication of the second role: that PR100 is an example of how to ground energy system analysis in energy justice. The ultimate hope is that the transition to renewable energy will reflect the interests of all the Puerto Rican people, and that they will be able to better participate in this transition because the tools and data from PR100 will be available to them.

Appendix E. Energy Justice Literature Review

E.1 Data Collection Methods

We identified and compiled a diverse collection of resources related to energy justice, including studies that focus on socioeconomic disparities, environmental impacts, policy frameworks, and community engagement in Puerto Rico's energy sector. We used academic databases such as PubMed, Scopus, Google Scholar, IEEE Xplore, and relevant academic libraries, and we used keywords and phrases such as energy justice, Puerto Rico, energy access, environmental equity, renewable energy, and policy analysis, and other phrases. To identify relevant articles, we searched for the terms within three database fields: the article title, abstract, and keywords.

We also searched the internet more broadly for web-based resources and reports, reviewing bibliographies previously compiled by colleagues conducting research on this topic, and asking members of the Advisory Group to provide input on this study for their suggestions on additional sources of local knowledge to include. We included peer-reviewed journal articles, government reports, academic books, conference papers, and publications from reputable organizations. We included videos, podcasts, documentaries for visual learners and workbooks for people who want to learn by doing. We excluded sources that are not directly relevant to energy justice or lack credibility.

E.2 Thematic Analysis

Academic Frameworks

Energy justice is a multidisciplinary concept that seeks to address social, economic, and environmental disparities related to the production, distribution, and consumption of energy. It emphasizes fairness, equity, and inclusivity in energy systems, policies, and decision-making. To understand the various facets of energy justice, researchers have developed academic frameworks and metrices. These frameworks provide an overview of the concepts and tenets related to energy justice, as we discussed above (Section 3.1, page 40). Bozeman, Nobler, and Nock (2022) provide a framework for integrating equity in energy and environmental research and practitioner settings, which they call "systemic equity," while Bouzarovski and Simcock (2017) apply an explicitly spatial lens to conceptualize energy poverty as a form of injustice. (Sovacool 2021) explains a framework that envisions the political ecology of low-carbon transitions and its energy justice implications as consisting of four distinct processes: enclosure, exclusion, encroachment, or entrenchment. Yet, others explore challenges in the energy justice field as it engages with research on renewable energy transitions in the United States. Despite the scholarly work to date, Jenkins et al.(K. E. H. Jenkins et al. 2021) observe the literature lacks diversity in its author basis and research design.

Case Studies

Case studies and experiences of specific communities across the themes of energy justice can provide valuable insights into real-world challenges and opportunities related to energy production, distribution, and consumption. Case studies and examples that illustrate the various energy justice themes include:

- Sustainable Community Aqueducts as Models for Community Microgrids: An In-Depth Case Study of Corcovada Arriba's Governance and Management Practices (Asencio Yace 2020)

- "Social Vulnerability and Power Loss Mitigation: A Case Study of Puerto Rico" (Boyle et al. 2022)
- "JUST-R Metrics for Considering Energy Justice in Early-Stage Energy Research" (Dutta et al. 2023)
- "Conceptualising Restorative Justice in the Energy Transition: Changing the Perspectives of Fossil Fuels" (Hazrati and Heffron 2021)
- "Gender Equality: A Case Study at the Río Piedras Market" (IREC, n.d.)
- "Solving Problems Like Maria: A Case Study and Review of Collaborative Hurricane-Resilient Solar Energy and Autogestión in Puerto Rico" (Krantz 2020)
- "Satellite-Based Assessment of Electricity Restoration Efforts in Puerto Rico After Hurricane Maria" (Román et al. 2019)

These case studies demonstrate the complexity of energy justice issues and how they manifest in different contexts. They also underscore the importance of considering multiple dimensions of justice when addressing energy-related challenges. Additionally, these cases highlight the need for inclusive and participatory decision-making processes that consider the voices and concerns of affected communities.

Economic and Workforce Development

In the context of energy justice, the impacts on jobs created or lost, workforce development and training, and economic participation are crucial aspects that directly affect the well-being of communities, particularly marginalized and underserved populations. Baker, DeVar, and Prakash (2019) provide tools for measuring economic equity in 100% renewable energy policy implementation[226] and describe how some groups profess that if the frontline communities benefit economically from the energy transition, that could remedy many of the social need and in turn lead to political empowerment through job creation, self-governance, and local ownership of economic resources. The Climate Justice Alliance gives a framework to understand regenerative economic solutions and ecological justice.[227]

Bennear (2022) provides evidence of greater negative impacts of the energy transition on lower-income households and on Black, Indigenous, and people of color—or BIPOC—households due to regressive increases in the cost of energy and less access to renewable energy and energy efficient technologies including electric vehicles. The author concludes that it is essential to prioritize strategies that promote inclusive economic participation, equitable job opportunities, accessible workforce development, and training programs to mitigate the negative impacts through policy choices.

Energy Access

Numerous studies underscore disparities in energy access across Puerto Rico. Hurricane Maria in 2017, which left many communities without power for unprecedented periods in Puerto Rico,

[226] "Just Transition: A Framework for Change," Climate Justice Alliance, https://climatejusticealliance.org/just-transition/.
[227] "A People's Orientation to a Regenerative Economy," Climate Justice Alliance, https://climatejusticealliance.org/regenerativeeconomy/.

revealed the vulnerability of Puerto Rico's energy infrastructure. Low-income neighborhoods and rural areas were disproportionately affected, exposing existing inequities in energy provision.

Asencio Yace (2020) observes that social factors such as community's empowerment, democratic structures, and justice-oriented principles help build trust and go a long way in disaster recovery efforts along with inclusion robust technologies. Jenkins et al. (2020) emphasize the need for targeted interventions to ensure equitable energy access.

Energy access means that energy services are affordable and within the financial reach of individuals and communities. Baker (Baker 2021) describes how affordability is crucial to ensure people do not have to choose between basic energy needs and other essential expenses, such as food, healthcare, and education expenses.

Energy Democracy

Energy democracy refers to a shift in the energy system toward greater participation, ownership, and control by communities and individuals. De Onís (2021) describes Puerto Rico's unique energy challenges, including a history of colonialism, vulnerable energy infrastructure, and the need for resilience in the face of natural disasters like hurricanes. Banet (2020) and Biaggi et al. (2021) highlight that in Puerto Rico, there is a growing push for decentralized, resilient energy systems and several elements of energy democracy are evident. Community-led initiatives and cooperatives have been established to develop and manage renewable energy projects, such as solar microgrids (Asencio Yace 2020) and IREC microgrid pilot projects."[228] These initiatives demonstrate how to decentralize energy production and provide local communities with greater control over their energy sources, which involves local generation, microgrids, and energy storage to ensure communities can maintain power during and after disasters. Many of these projects are discussed in the case study theme.

Environmental and Health Impacts

The environmental impacts of energy production and consumption also intersect with questions of justice in Puerto Rico. The concentration of polluting power generation facilities in marginalized communities has raised concerns about environmental justice. Zinecker et al. (2014) discuss the health and environmental costs of slow action and provides relevant case studies from different regions of the world, while Carley, Engle, and Konisky (2021) focus on the United States and outline adverse effects of the energy transition, such as disruptions to labor markets, higher energy prices, pollution, and health burdens. Studies like Baker et al. (2019) highlight the link between energy-related pollution and the health disparities experienced by vulnerable populations. Bullard (2005) established a connection between race and "environmental racism" by highlighting commercial hazardous waste landfills siting in predominantly African American communities even though African Americans made up only 20% of the region's population in the study. Chapter 10 ("Environmental Justice") of NREL's LA 100 study (Hettinger et al. 2021) reviews some of three areas of distributional justice: technology deployment of customer rooftop solar, air pollutant concentrations (fine particulate matter and ozone), and air-quality-related health impacts (emergency room visits from asthma, cardiovascular-related hospital admissions, and premature mortality). These findings underscore

[228] "Microgrid Pilot Projects," IREC, https://irecusa.org/programs/puerto-rican-solar-business-accelerator/microgrid-pilot-projects/.

the importance of transitioning to renewable energy sources to mitigate both environmental and social injustices.

Foundational Works

Energy justice is a multidisciplinary field that has generated a growing body of literature. Sovacool (2012) gives us a comprehensive overview of the energy justice literature and introduces key concepts, dimensions, and principles of energy justice, including distributional, procedural, and recognition justice. McCauley et al. (2019) provides an accessible overview of energy justice concepts and their application in various contexts. Jenkins et al. (2016) show a conceptual review and a research agenda along with three areas for future research: investigating the nonactivist origins of energy justice, engaging with economics, and uniting systems of production and consumption. Baker, DeVar, and Prakash (2019) developed a workbook to bridge the gap between theories and practices of energy justice, along with an Energy Justice Scorecard that provides guidance to support equity-centered energy policy. These core works provide a foundation for understanding the concepts and frameworks of energy justice, and they cover a range of topics related to energy access, distribution, environmental justice, and social equity within the energy sector. Researchers, policymakers, and practitioners interested in energy justice may find these resources valuable for further exploration and study.

Infrastructure Interdependencies

Critical infrastructure and energy justice are intertwined in Puerto Rico, where the energy system is central to the well-being of communities and the territory's overall resilience. Puerto Rico has faced significant challenges related to its energy infrastructure, especially in the aftermath of hurricanes and other natural disasters. Boyle et al. (2022) discuss the importance of identifying critical system components of the infrastructure and use component-based event simulation integrated with a social vulnerability modeling component to develop a decision metric for targeted transmission line hardening.

By transitioning to renewable, more resilient energy sources; promoting community ownership; and implementing policy reforms, Puerto Rico can work toward a more just and sustainable energy system that benefits all residents, especially those in vulnerable communities. This approach can enhance the commonwealth's resilience and improve the overall quality of life for its residents. Montoya-Rincon et al. (2023) evaluate the effectiveness of various interventions aimed at reducing vulnerability by considering power and water infrastructure while also considering the social vulnerability of affected communities associated with the physical infrastructure upgrades, and they reiterate that hardening transmission lines would provide uninterrupted service to more of the vulnerable population.

Achieving energy justice in Puerto Rico involves addressing the vulnerabilities and challenges in its critical energy infrastructure. Jeffers et al. (2018) analyze resilience node locations to create a portfolio of 159 microgrid options throughout Puerto Rico and assess the impact of these microgrids on the region's ability to provide critical services during an outage, and they compare this impact to high-level estimates of cost for each microgrid to generate a set of efficient microgrid portfolios.

Land Use and Siting

Land use and siting decisions play a significant role in the context of energy justice in Puerto Rico, as they can have both positive and negative impacts on local communities, particularly in terms of environmental, social, and economic impacts. Proper land use and siting can help reduce the vulnerability of communities both to power outages during storms and to project delays and risks. Elmallah and Rand (2022) highlight the limited opportunities for participation and decision-making input afforded to the public in wind farm siting in the United States. In an example from Puerto Rico, Sotomayor Ramírez, Rodríguez Pérez, and Pagán Roig (2015) describe citizen participation in the process of approving the Santa Isabel Wind Farm project, how implementation was fast-tracked, and impacts on local agricultural activities. Puerto Rico's susceptibility to hurricanes and extreme weather events makes siting decisions critical for ensuring the resilience of energy infrastructure. Martinuzzi, Gould, and Ramos González (2007) integrate geospatial technology and population census data to discover that developments occur in both low-density patterns of construction and sparsely populated neighborhoods. Their study reinforces the need for efficient land use planning and provides information to support research and planning efforts related to land development and conservation. A related resource from the U.S. Department of Agriculture is the Land Evaluation and Site Assessment, or LESA, system[229] that can be used to rank parcels of land on the basis of local resource evaluation and site considerations. Energy justice encourages integrated land use planning that considers the long-term impacts of energy projects on local ecosystems, water resources, and biodiversity. Such an approach seeks to balance energy needs with environmental sustainability.

By ensuring siting decisions are made with transparency, community engagement, and a focus on equitable outcomes, Puerto Rico can work toward a more just and sustainable energy future that benefits all its residents and respects the rights and well-being of local communities, including Indigenous groups. The location of energy facilities, such as power plants, transmission lines, and renewable energy projects, can disproportionately affect marginalized communities in terms of environmental pollution, health risks, and ecosystem disruption. Energy justice advocates argue for equitable distribution of these impacts and that regulations prioritize equitable and sustainable development, as well as community participation. Toward this end for Puerto Rico, a member of the Advisory Group for the study suggested the creation of an advisory body such as a siting committee for Puerto Rico that would include experts, the public, farmers, academia, and businesses to advise on siting decisions, similar to Maryland's Soil Health Advisory Committee.[230][231] In summary, land use and siting decisions in Puerto Rico's energy sector have significant implications for energy justice.

Puerto Rico

Energy justice resources specifically pertaining to or referencing Puerto Rico may be somewhat limited in comparison to more generalized energy justice literature. However, there are still valuable resources and research that discuss Puerto Rico's energy challenges and the concept of energy justice in the context of Puerto Rico. For example, Sanzillo and Vila-Biaggi (2020) offer

[229] Land Evaluation and Site Assessment, U.S. Department of Agriculture, https://www.nrcs.usda.gov/conservation-basics/natural-resource-concerns/land/evaluation-and-assessment

[230] Personal correspondence: email from David Sotomayor to PR100 project team on November 29, 2023

[231] "The Maryland Healthy Soils Program Final Report: A Path Forward," Maryland Department of Agriculture, https://mda.maryland.gov/resource_conservation/Pages/Maryland-Healthy-Soils-Program-Final-Report.aspx

a comprehensive analysis of Puerto Rico's energy system, including discussions on policy, economics, and energy justice considerations. And EPA (2016) discusses the vulnerabilities of Puerto Rico's energy infrastructure to climate change and natural disasters, emphasizing the importance of resilience in the context of energy justice. Also, the Organizing for a Just Recovery in Puerto Rico and Beyond campaign[232] examines broader social, economic, and environmental justice issues in Puerto Rico and discusses the need for a just energy transition as part of the commonwealth's recovery from recent hurricanes. The availability of resources and research related to Puerto Rico's energy justice is evolving, and those resources are becoming more inclusive.

Utility Actions

Actions by utilities are central to the concept of energy justice in Puerto Rico, as they directly impact the availability, affordability, reliability, and sustainability of energy services for the commonwealth. The governance and management of PREPA have been a subject of debate and reform efforts. Energy justice advocates argue for public ownership or community participation in the utility to ensure energy decisions prioritize the well-being of Puerto Rico's residents. Baker, DeVar, and Prakash (2019) discuss how utility actions should consider the concept of a "just transition" by providing support, retraining, and economic opportunities for workers and communities affected by the shift from fossil fuels to renewable energy sources. Utility actions related to infrastructure investments, grid modernization, and renewable energy integration can have significant implications for energy justice. Prioritizing investments in resilient and sustainable infrastructure is crucial for the Puerto Rico's resilience. Utility actions in Puerto Rico have a significant impact on energy justice, encompassing affordability, reliability, sustainability, and equitable access to the benefits of renewable energy. A just energy transition in the region requires utility actions that prioritize the well-being of all residents and communities while addressing the unique challenges and vulnerabilities faced by Puerto Rico.

While the existing literature provides valuable insights into energy justice in Puerto Rico, several gaps remain. Limited research exists on the long-term impacts of energy justice initiatives, and more studies are needed to assess the effectiveness of policy interventions and community engagement efforts. Additionally, a comprehensive analysis of the potential trade-offs between various energy justice goals, such as affordability and environmental sustainability, is warranted. However, the literature reviewed does demonstrate that energy justice is a multipolar issue in Puerto Rico and that it intersects with socioeconomic, environmental, and policy considerations. The complexities of the energy landscape demand a holistic approach that addresses not only access and distribution but also the broader challenges faced by marginalized communities. Our literature review sets the stage for further research and policy interventions aimed at achieving energy justice and sustainable development in Puerto Rico.

[232] "Organizing for a Just Recovery in Puerto Rico and Beyond," Center for Popular Democracy, accessed 2018, https://www.populardemocracy.org/campaign/organizing-just-recovery-puerto-rico-and-beyond.

Appendix F. Modeling Tools Employed in PR100

Table F-1. Modeling Tools Employed in PR100 Study

Acronym	Name	Organization	Purpose
—	Aurora	Energy Exemplar	Capacity expansion and energy system interdependency modeling
CGE	Computable General Equilibrium	—	Economy-wide model to derive policy impacts in the economy
C-PAGE	Chronological AC Powerflow Automated Generation tool	PNNL	Realistic, long-term planning for grid operators
DCAT	Dynamic Contingency Analysis Tool	PNNL	Assessment of impact and likelihood of extreme contingencies
dGen	Distributed Generation Market Demand Model	NREL	Distributed generation modeling and PV + storage adoption modeling
EGRASS	Electrical Grid Resilience and Assessment System	PNNL	Modeling of extreme events and power systems
—	Energy Justice Dashboard (BETA)	DOE	Visualization of energy justice indicators
—	Engage	NREL	Capacity expansion and energy system interdependency modeling
HELICS	Hierarchical Engine for Large-scale Infrastructure Co-Simulation	PNNL	Interdependency impact co-simulation
JEDI	Jobs and Economic Development Impact Models	NREL	Modeling of local economic impacts of renewable projects
PRAS	Probabilistic Resource Adequacy Suite	NREL	Resource adequacy modeling
PRIIA	Puerto Rico Infrastructure Interdependency Assessment	Argonne National Laboratory	Infrastructure interdependency assessment
PSCAD	Power Systems Computer Aided Design	Manitoba Hydro International Ltd.	Power flow and dynamic analysis
PSS/E	Power System Simulator for Engineering	Siemens	Transmission planning analysis
RAPT	Resilience Assessment and Planning Tool	FEMA	Resilience planning
ReNCAT	Resilient Node Cluster Analysis Tool	Sandia National Laboratories	Social burden analysis
reV	Renewable Energy Potential Model	NREL	Incorporate exclusions to determine available renewable resource by region

Acronym	Name	Organization	Purpose
SIIP	Scalable Integrated Infrastructure Planning Model	NREL	Grid operations modeling
SUPRA	Standardized Utility Pro-Forma Financial Analysis	Lawrence Berkeley National Laboratory	Determination of electric rates

Appendix G. Electric Load Modeling Methodology

G.1 End-Use Load Methodology

Annual Sales: Residential Sector Projections

To create the residential sector electricity sales projection for FY19–FY38, the PREPA 2019 IRP used a linear regression equation built using monthly population, real GNP, and cooling degree day data (Siemens Industry 2019). The PR100 projection for FY23–FY51 used the same linear regression equation as the 2019 IRP; updated the monthly input values for population, real gross national product (GNP), and cooling degree day (CDD) as described in Section 5.1.1; and manually calibrated the projection's starting point in FY23 to more closely align with FY19–FY22 actual data obtained from LUMA.

The 2019 IRP residential sales projection is lower than the historical residential sales from FY19 to FY22 and is lower than the PR100 projection from FY23 to FY38 (Figure G-1). This is because all the input variables are higher in the PR100 projection than in the 2019 IRP, aside from real GNP in FY38. The fluctuations in the PR100 projection between FY40 and FY46 are primarily attributed to fluctuations in the CDD data, which were based on climate projections from Argonne National Laboratory using climate models that show year-over-year variation in weather and climate.

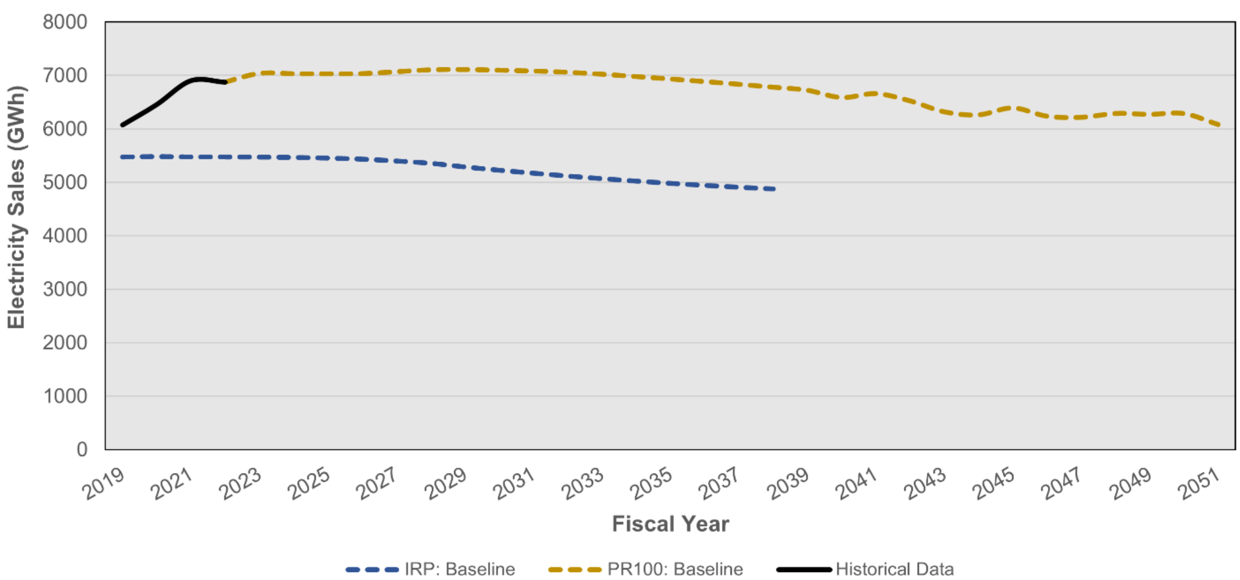


Figure G-1. IRP versus PR100 end-use sales: Residential sector projections, FY19–FY51

Annual Sales: Commercial Sector Projections

To create the commercial sector electricity sales projection for FY19–FY38, the 2019 IRP used a linear regression equation that incorporated monthly population and CDD data (Siemens Industry 2019). The PR100 projection for FY23–FY51 used the same linear regression equation as the 2019 IRP, updated the monthly input values for population and CDD as described in Section 5.1.1, and manually calibrated the projection's starting point in FY23 to more closely align with FY19–FY22 historical data obtained from LUMA.

The 2019 IRP commercial sales projection is higher than both the historical commercial sales data from FY19 to FY22 and the PR100 projection from FY23 to FY38 (Figure G-2).This is because, although the input variables are higher for the PR100 projection compared to the 2019 IRP, the linear regression equation used in the 2019 IRP overestimated commercial sales from FY19 to FY22. Thus, the PR100 output projection was adjusted accordingly to more closely align with the historical data. The fluctuations in the PR100 projection between FY40 and FY46 are primarily attributed to fluctuations in the CDD data, which were based on climate projections from Argonne National Laboratory using climate models that show year-over-year variation in weather and climate.

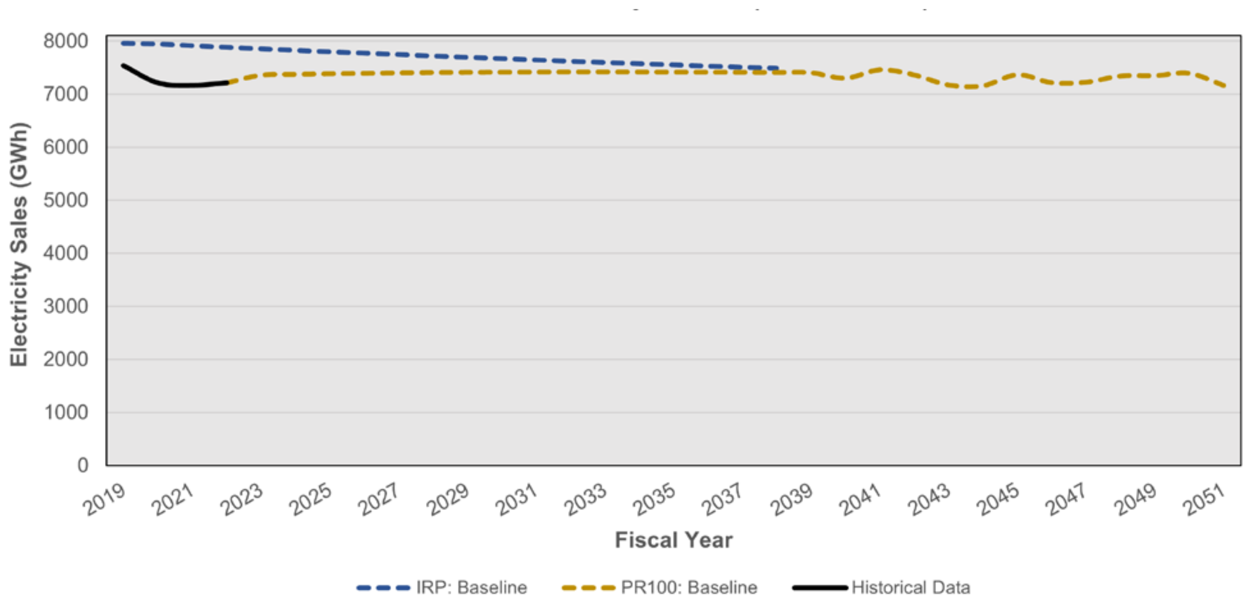


Figure G-2. 2019 IRP versus PR100 end-use sales: Commercial sector projections, FY19–FY51

Annual Sales: Industrial Sector Projections

To create the industrial sector electricity sales projection for FY19–FY38, the 2019 IRP used a linear regression equation that incorporated monthly manufacturing employment, real GNP, and CDD data (Siemens Industry 2019). The PR100 projection for FY23–FY51 used the same linear regression equation as the 2019 IRP; updated the monthly input values for manufacturing employment, real GNP, and CDD as described in Section 5.1.1; and manually calibrated the projection's starting point in FY23 to more closely align with FY19–FY22 historical data obtained from LUMA.

The 2019 IRP industrial sales projection is lower than the historical industrial sales data from FY19 to FY22, lower than the PR100 projection from FY23 to FY25 and FY27 to FY36, and higher than the PR100 projection in FY26 and from FY37 to FY38 (Figure G-3). This is because of the interaction of the linear regression equation, which underestimated industrial electricity sales from FY19–FY22, with the input variables, which show different trends in the PR100 projection compared to the 2019 IRP. Most significantly, the PR100 manufacturing employment projections did not increase at as high of a rate as those used in the 2019 IRP. The fluctuations in the PR100 projection between FY40 and FY46 are primarily attributed to fluctuations in the

CDD data, which were based on climate projections from Argonne National Laboratory using climate models that show year-over-year variation in weather and climate.

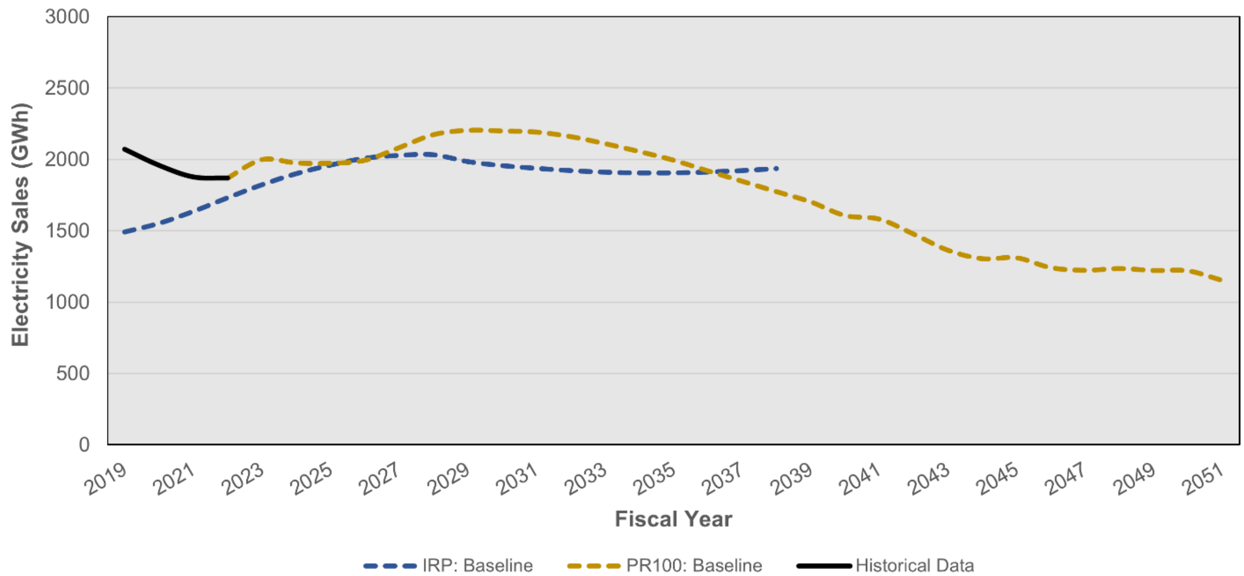


Figure G-3. 2019 IRP versus PR100 end-use sales: Industrial sector projections, FY19–FY51

Annual Sales: Public Lighting, Agriculture, and Other Sector Projections

The 2019 IRP also projected electricity sales from FY19 to FY38 for three additional sectors: public lighting, agriculture, and other. In the 2019 IRP projection, the sales for these sectors—which comprised approximately 2% of sales in FY17—are assumed to follow the same growth rate for each month in each year as the combined residential, commercial, and industrial sales. The PR100 projection for FY23–FY51 used the same assumption as the 2019 IRP and manually calibrated the projection's starting point in FY23 to more closely align with FY19–FY22 historical data obtained from LUMA.

The 2019 IRP projection for these sectors is higher than the historical data in FY19 and from FY21 to FY22, lower than the historical data in FY20, and higher than the PR100 projection from FY23 to FY38 (Figure G-4). This is because the 2019 IRP overestimated public lighting, agriculture, and other sales from FY19 to FY22. The fluctuations in the PR100 projection between FY40 and FY46 are primarily attributed to fluctuations in the CDD data, which were based on climate projections from Argonne National Laboratory using climate models that show year-over-year variation in weather and climate.

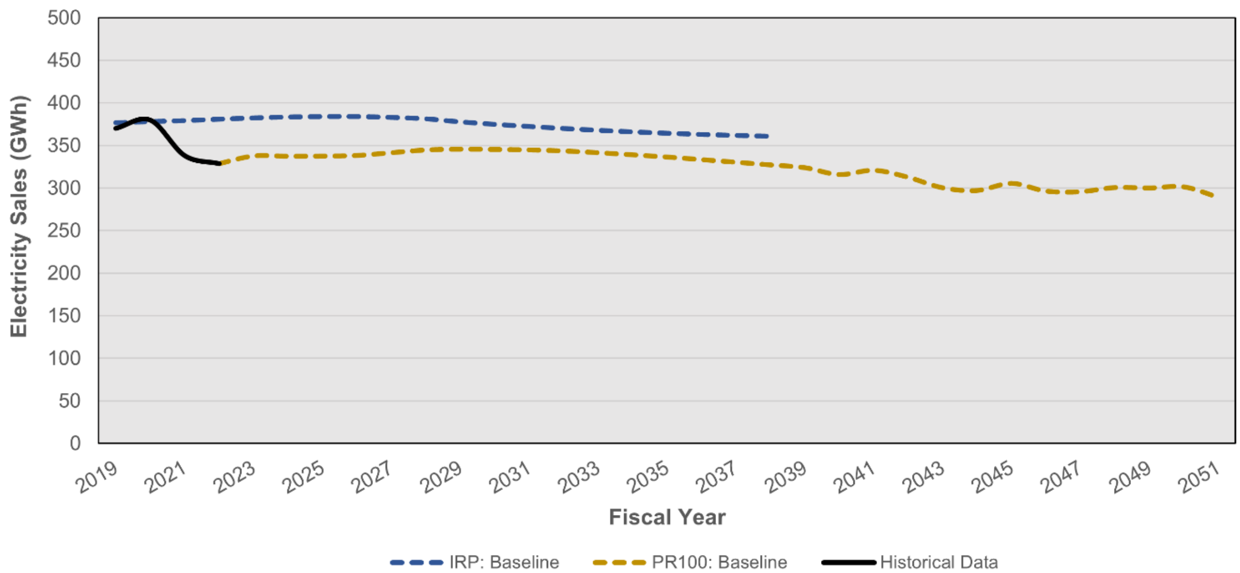


Figure G-4. 2019 IRP versus PR100 end-use sales: Public lighting, agriculture, and other sector projections, FY19–FY51

Annual Sales: Total Baseline Projections

The annual sector-level sales projections for end-use loads (i.e., residential, commercial, and industrial) were summed to determine the total annual baseline sales projection. The manual calibrations to the PR100 electricity sales projections for each sector, which were conducted to more closely align these sector-level projections with FY19–FY22 historical data obtained from LUMA, did not change the total annual sales projection. Instead, the calibration adjusted the sector-specific breakdown of total sales (e.g., the proportion of residential sales within total sales). The 2019 IRP projection for total sales (i.e., the sum of all sector-level projections) is lower than the actual data from FY19–FY22 and lower than the PR100 projection from FY23 to FY38 (Figure G-5).

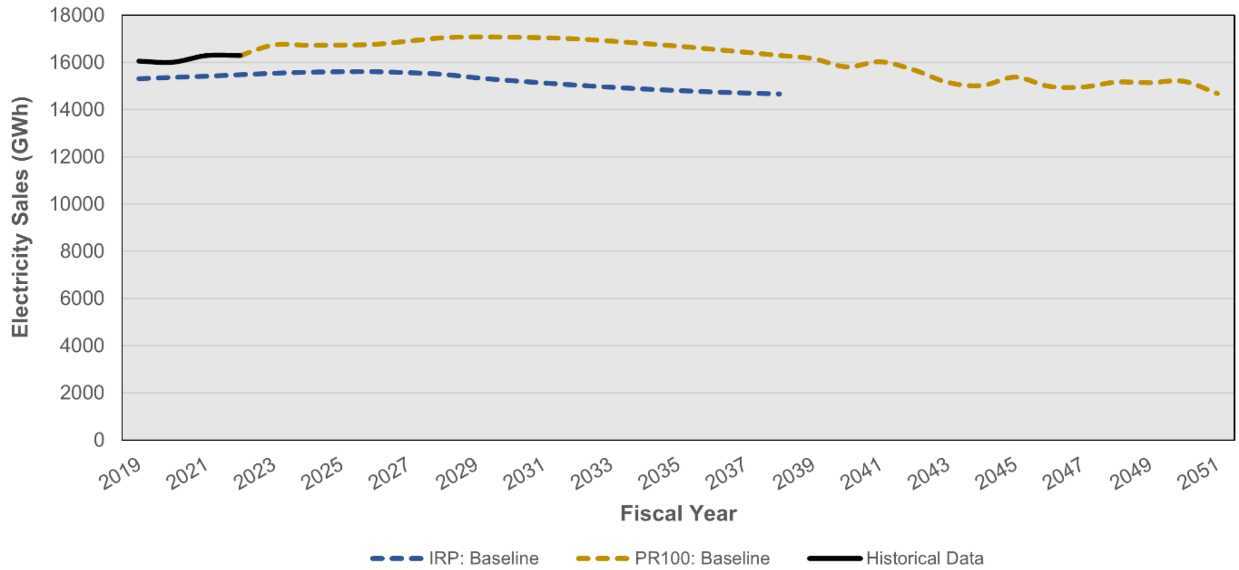


Figure G-5. 2019 IRP versus PR100 end-use sales: Total baseline projections, FY19–FY51

Annual Sales: High, Mid case, and Low Projections

The methodology used to convert the PR100: Baseline projection to a spread of High, Mid case, and Low projections—which are displayed in Figure G-6—is described further in Section G.2 (page 694). Only the Mid case projection is used in the PR100 analysis; these sensitivities were developed for consistency with and to make comparisons to the 2019 IRP.

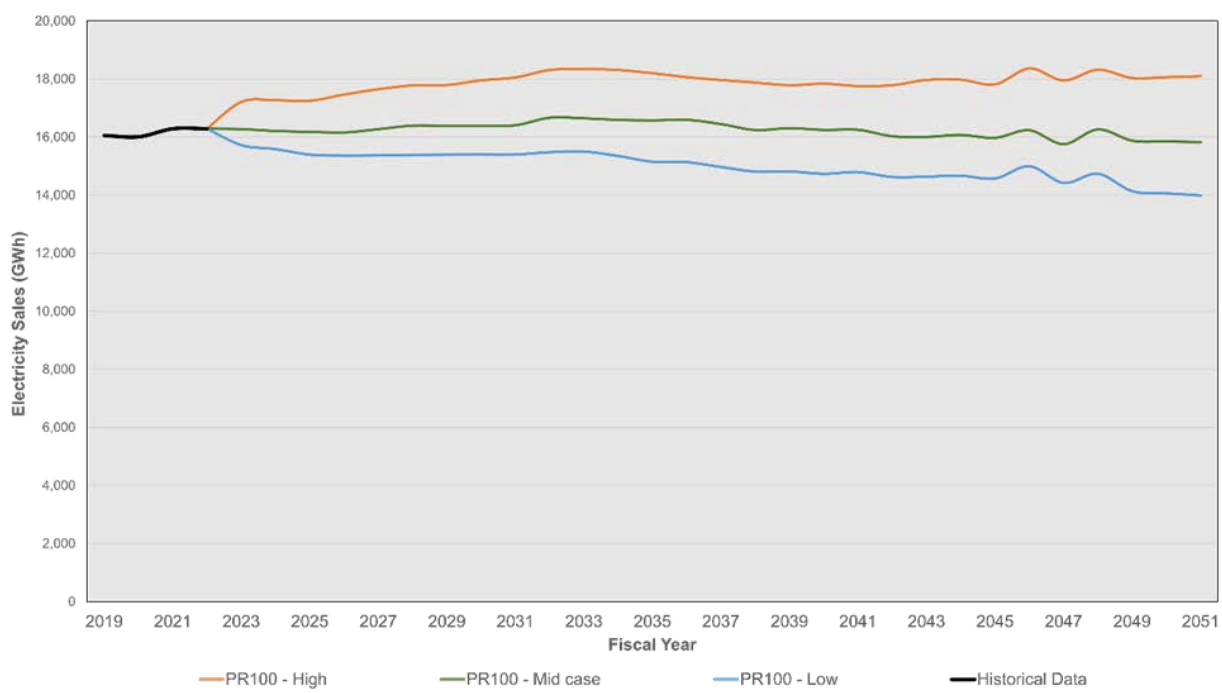


Figure G-6. PR100 end-use sales: Total High, Mid case, and Low projections, FY19–FY51

The Mid case end-use projection used in PR100 shows a general trend of slightly decreased end-use sales over time. This is primarily because of forecasted long-term declines in population and real GNP. This projected decline was seen in the 2019 IRP as well, but this did not materialize in the years since (FY19–FY23). To account for a future in which loads do not decrease as projected, we developed a fourth end-use projection: Stress. This projection assumes the combination of end-use loads and energy efficiency will result in flat annual electricity sales and electric loads from FY23 to FY51. EV loads will lead to increases in the Stress load above this flat line projection. The energy efficiency projection is described in Section 5.2, and the EV projections are described in Section 5.3. The creation of the overall Stress electric load variation and its rationale are described further in Section 5.4.

Hourly Sales: Sectoral and Regional Projections

The PR100 High, Mid case, and Low annual sales projections for end-use loads were also converted to hourly projections, per sector, from FY23 to FY51. Each fiscal year starts on a Sunday to align with the FY19 baseline, and the impact of leap years is ignored. The hourly electricity sales profile by sector in FY51 for the PR100 Mid case projection is shown in Figure G-7, and the average hourly electricity sales profile by sector for a day in July of FY51, based on this projection, is shown in Figure G-8.

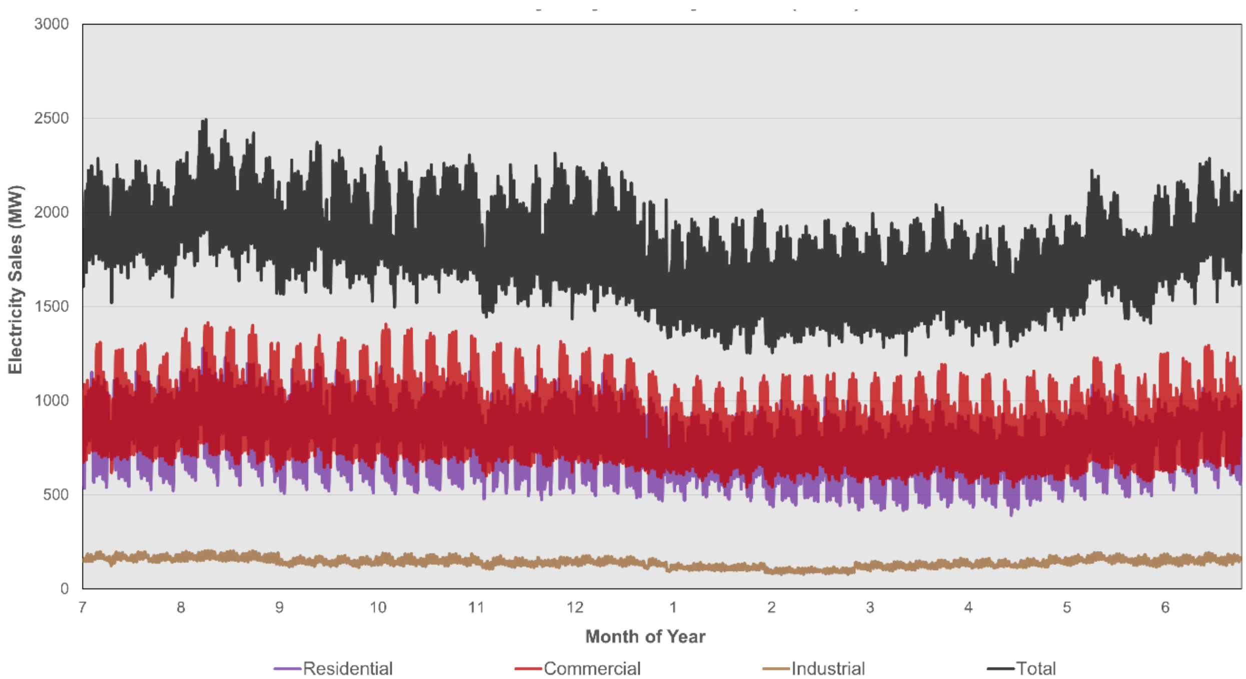


Figure G-7. PR100 Mid case end-use sales: Hourly projection by sector, FY51

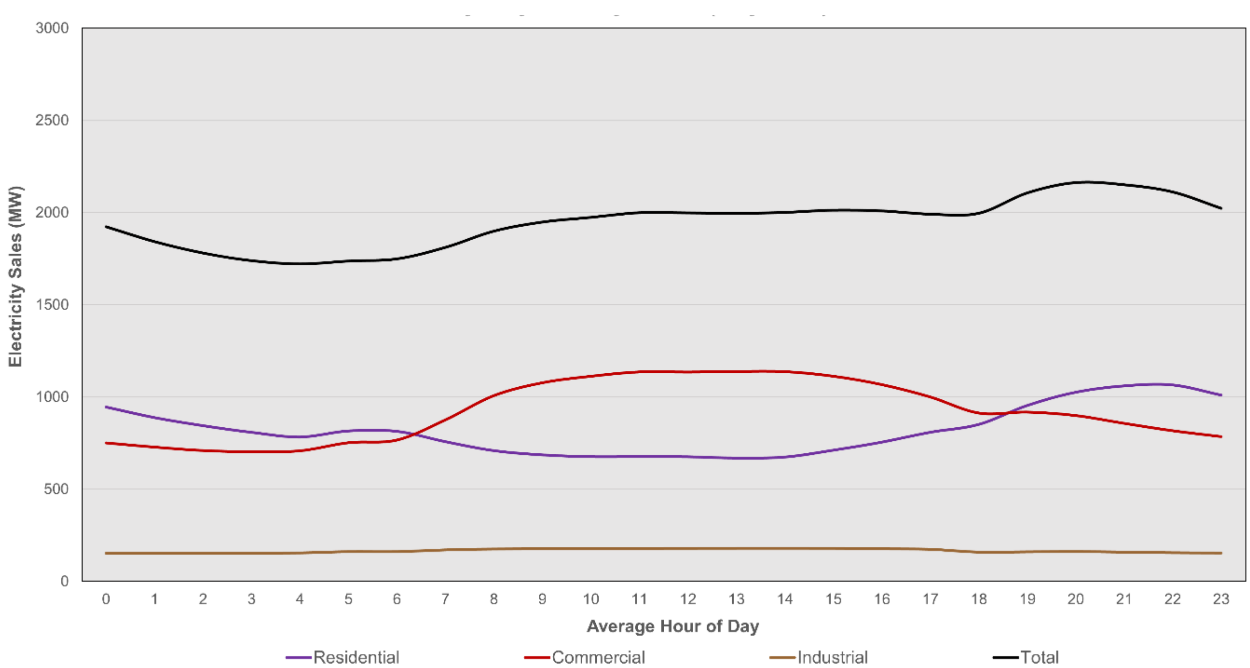


Figure G-8. PR100 Mid case end-use sales: Hourly projection by sector, July 2051

The PR100 territory-wide hourly sales projections per sector for end-use loads from FY23 to FY51 were then disaggregated by municipality. Puerto Rico has 78 municipalities, which are administrative subdivisions. This process, which assumes the percentage of sector-level end-use sales allocated to each municipality remains constant, is described further in Section G.2 (page 694). Figure G-9 displays the PR100 Mid case residential sector sales projection for end-use loads from FY23 to FY51, disaggregated by municipality.

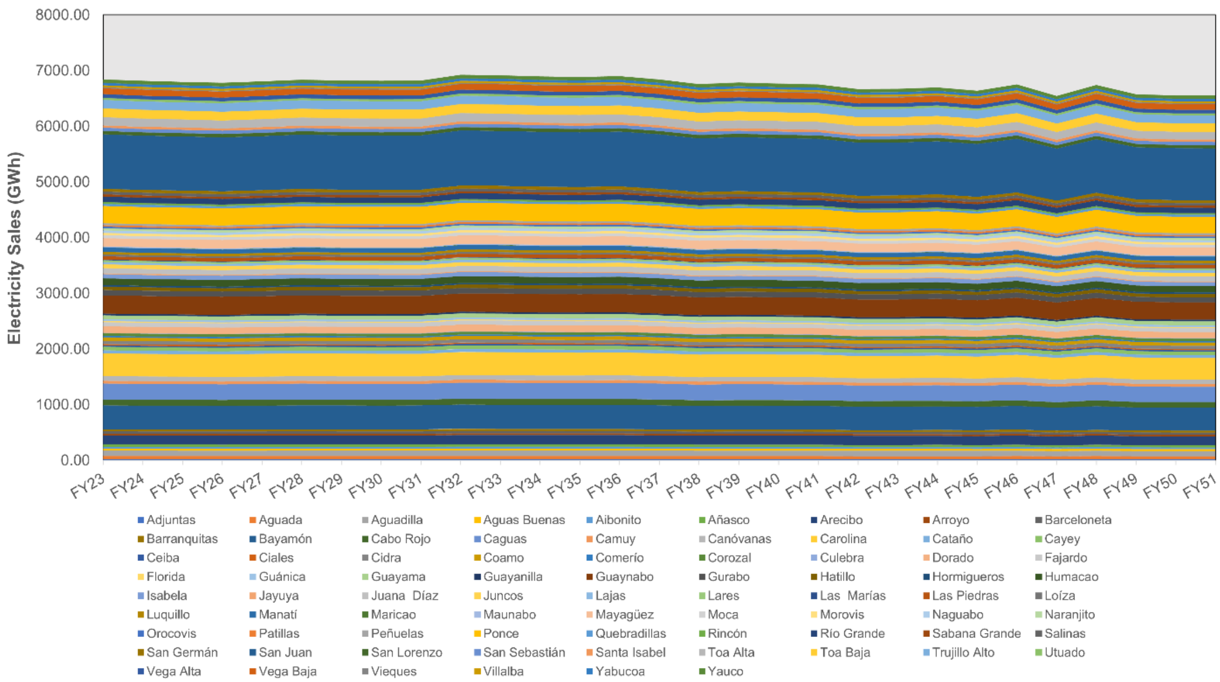


Figure G-9. PR100 Mid case end-use sales: Residential sector projection by municipality, FY23–FY51

G.2 End-Use Loads Material

Annual Sales: High, Mid case, and Low Projections

The 2019 IRP projection for total end-use electricity sales, which is created from the linear regression equations, is referred to as the IRP: Baseline, and the corresponding PR100 projection is referred to as the PR100: Baseline (Section 5.1, page 119). The 2019 IRP contained stochastic projections to show how sales growth could vary from the IRP: Baseline projection to account for uncertainty in the input variables. For instance, the IRP contains an IRP: 85% - Stochastic projection, which represents the 85th percentile of the iterations. The PR100: Baseline projection was scaled accordingly, using the same scaling factors as the IRP, to create a PR100: 85% - Stochastic projection in addition to the other stochastic projections contained in the IRP (5%, 25%, 50%, 75%, and 95%). The PR100 stochastic projections for total end-use electricity sales are higher than those in the IRP (Figure G-10). This is because the PR100: Baseline projection is higher than the IRP: Baseline projection. The fluctuations in the stochastic projections are attributed to uncertainties and potential randomness in the input variables (e.g., population, GNP, CDD, and manufacturing employment).

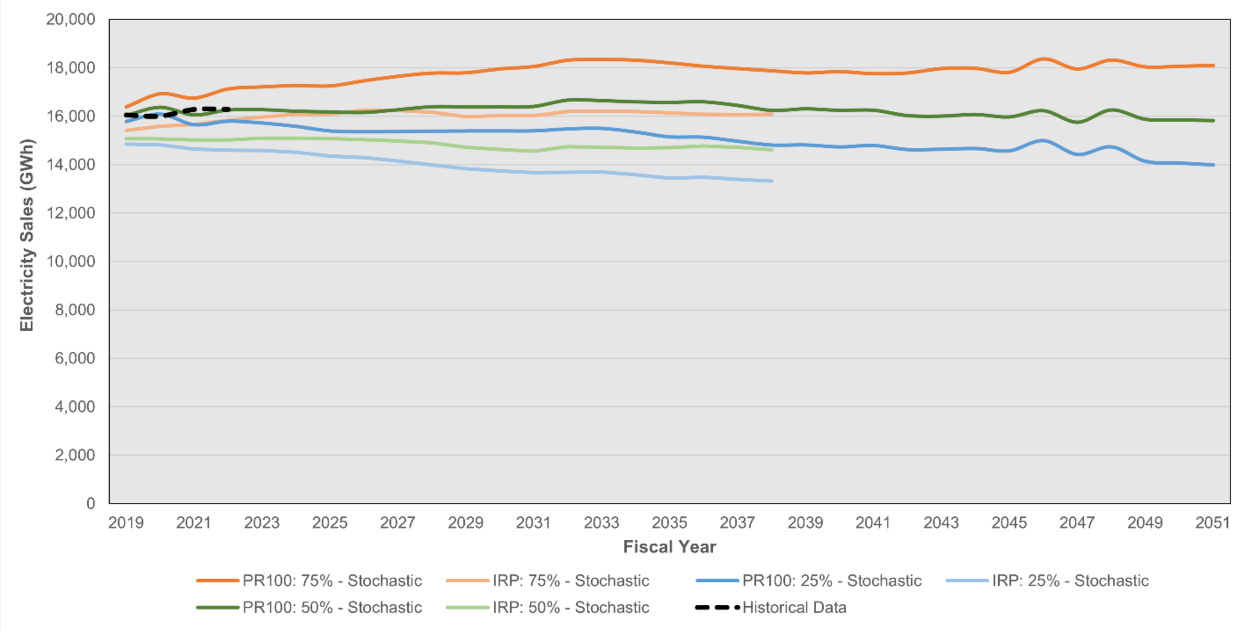


Figure G-10. 2019 IRP versus PR100 end-use sales: Total stochastic projections, FY19–FY51

The PR100 stochastic end-use sales projections were compared to the FY19–FY22 actual data obtained from LUMA to select High, Mid case, and Low annual projections. The LUMA data are at the lower bound of the PR100 projections, suggesting that the regression model—with updated input variables—is overestimating sales (Figure G-11). Because the regression model overestimated total end-use electricity sales for FY19–FY21, the PR100: 75% - Stochastic projection was selected as the High projection. The PR100: 50% - Stochastic projection was selected as the Mid case projection, and the PR100: 25% - Stochastic projection was selected as the Low projection.

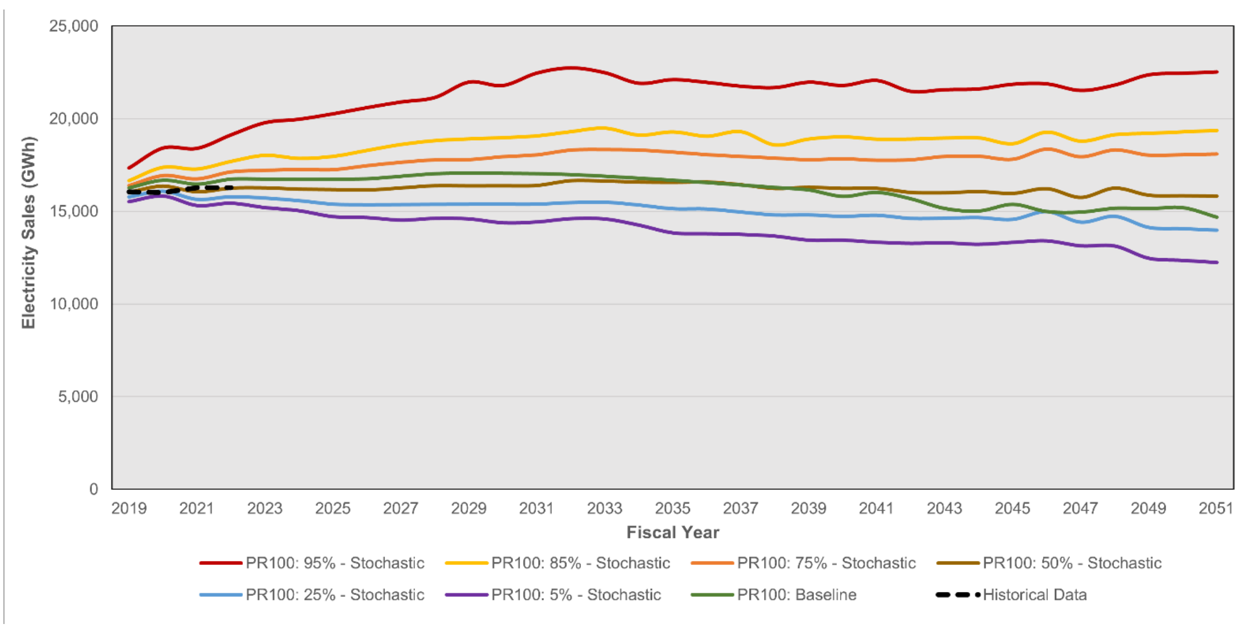


Figure G-11. PR100 end-use sales: Total stochastic projections, FY19–FY51

Hourly Sales: Sectoral and Regional Projections

This section details the methodology used to convert the PR100 High, Mid case, and Low annual sales projections for end-use loads to hourly projections, per sector, from FY23 to FY51. Historical hourly end-use sales data from LUMA for FY19 were used as the baseline; however, these data were not disaggregated by sector. Constructed hourly sales data per sector from Siemens for FY17 were available. These data were incomplete and therefore modified so that each month's sales profile for each sector consisted of a repeating week based on the average week for that month. The PR100 projections assume the sector-level breakdown of hourly sales in FY19 is equivalent to that of this modified FY17 constructed data set. The FY19 sector-level sales data were then scaled according to the monthly electric sales projections from FY23 to FY51 to project the hourly end-use sales per sector for these years.

To disaggregate these projections by municipality in Puerto Rico, data on sector-specific (i.e., residential, commercial, industrial, and other) electricity sales for each municipality were obtained for FY13–FY20 from LUMA (Figure G-12). In this case, "other" includes agriculture and public lighting. For instance, the most populous municipality, San Juan (9.97% of total population), accounted for 14.27% of residential electricity sales, 26.23% of commercial electricity sales, 2.18% of industrial electricity sales, and 8.61% of other electricity sales (including agriculture and public lighting) in FY19. The percentage breakdowns of sectoral demand by municipality are assumed to remain constant at FY19 levels throughout the analysis period. Therefore, it is assumed that in FY51, San Juan accounts for the same percentages of sectoral sales as it did in FY19. These percentage breakdowns were used to convert the territory-wide hourly end-use electricity sales projections into municipality-level projections.

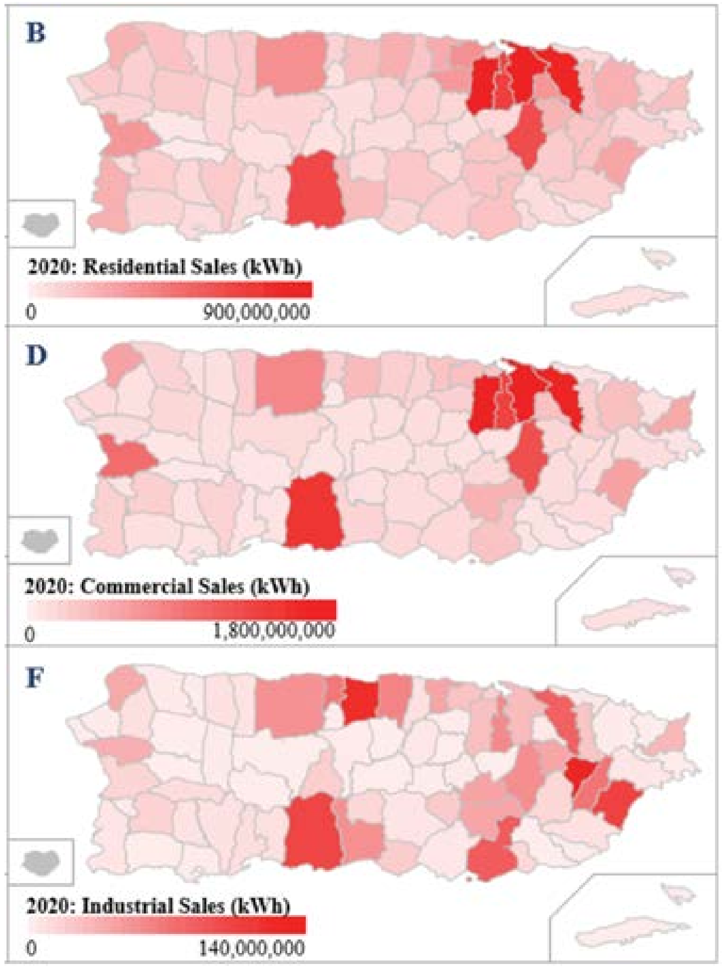


Figure G-12. Distribution of residential, commercial, and industrial electricity sales in Puerto Rico, FY20

Source: PREPA 2021 Fiscal Plan

Appendix H. Supplemental Material for Power System Operational Scheduling

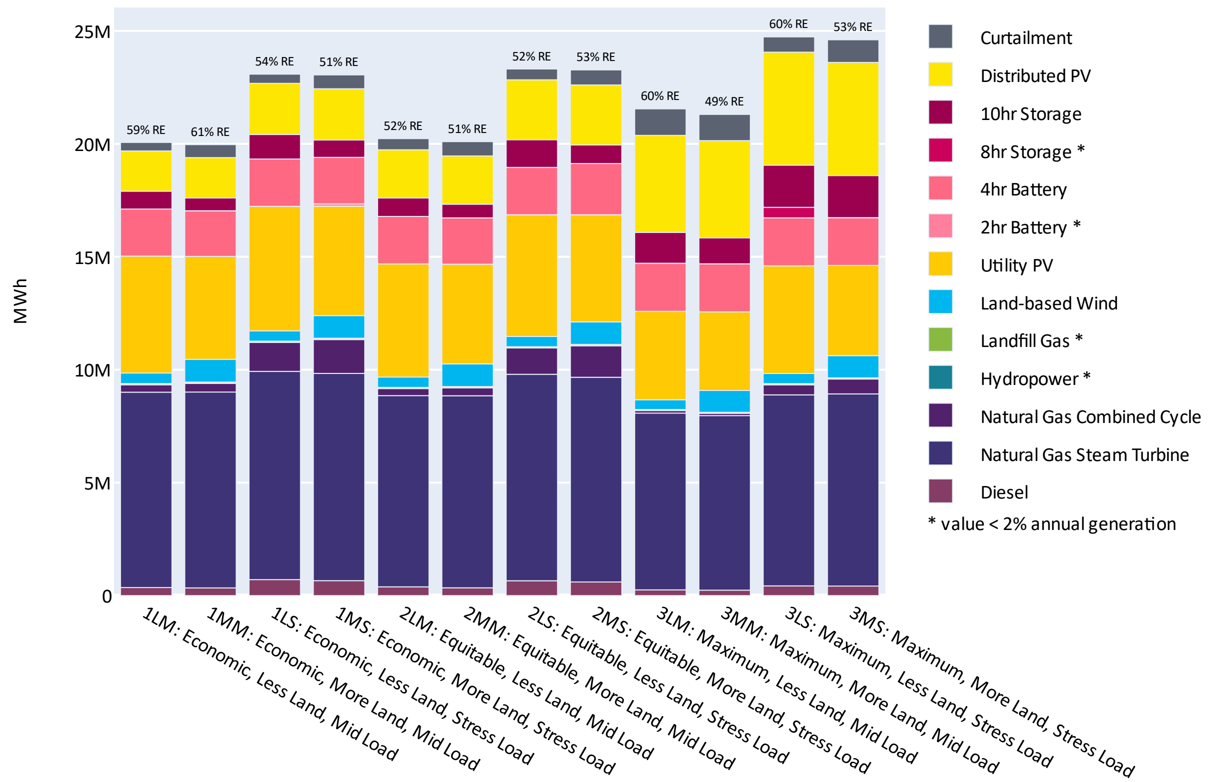


Figure H-1. Total annual electricity generation, by scenario, 2028

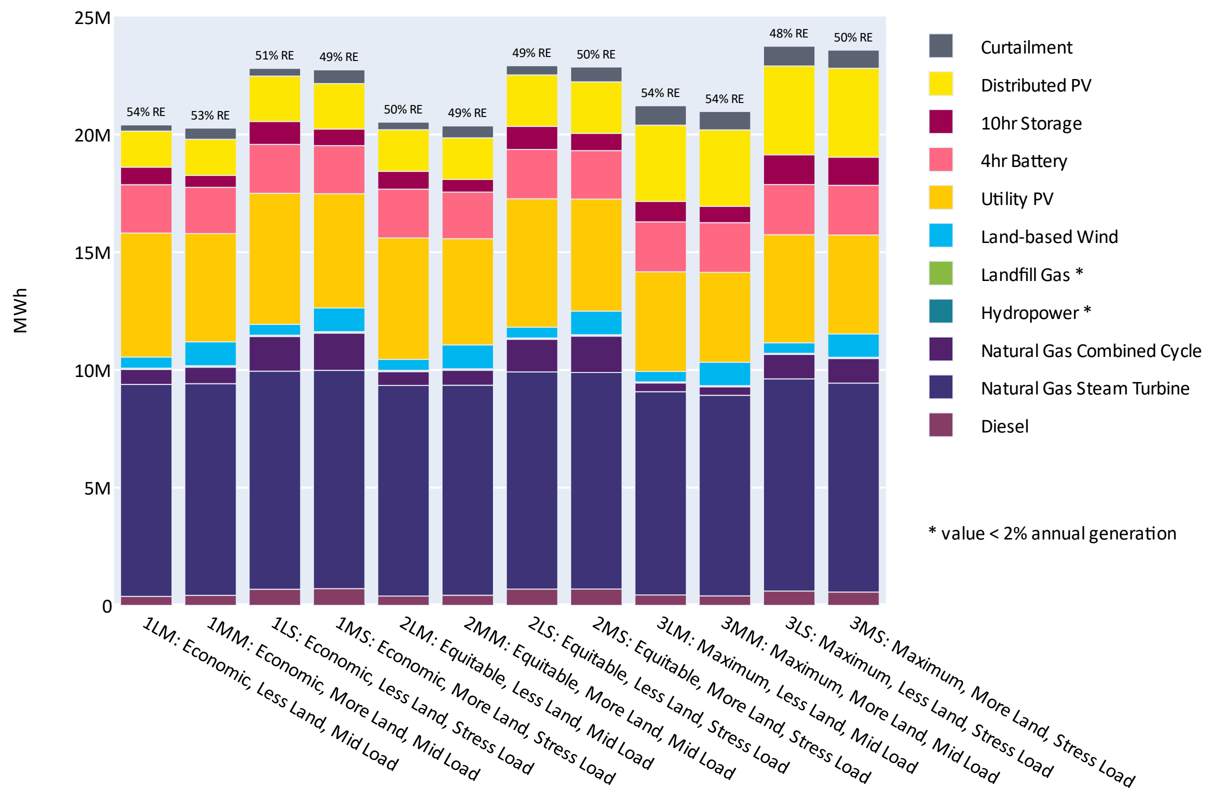


Figure H-2. Total annual electricity generation, by scenario, 2030

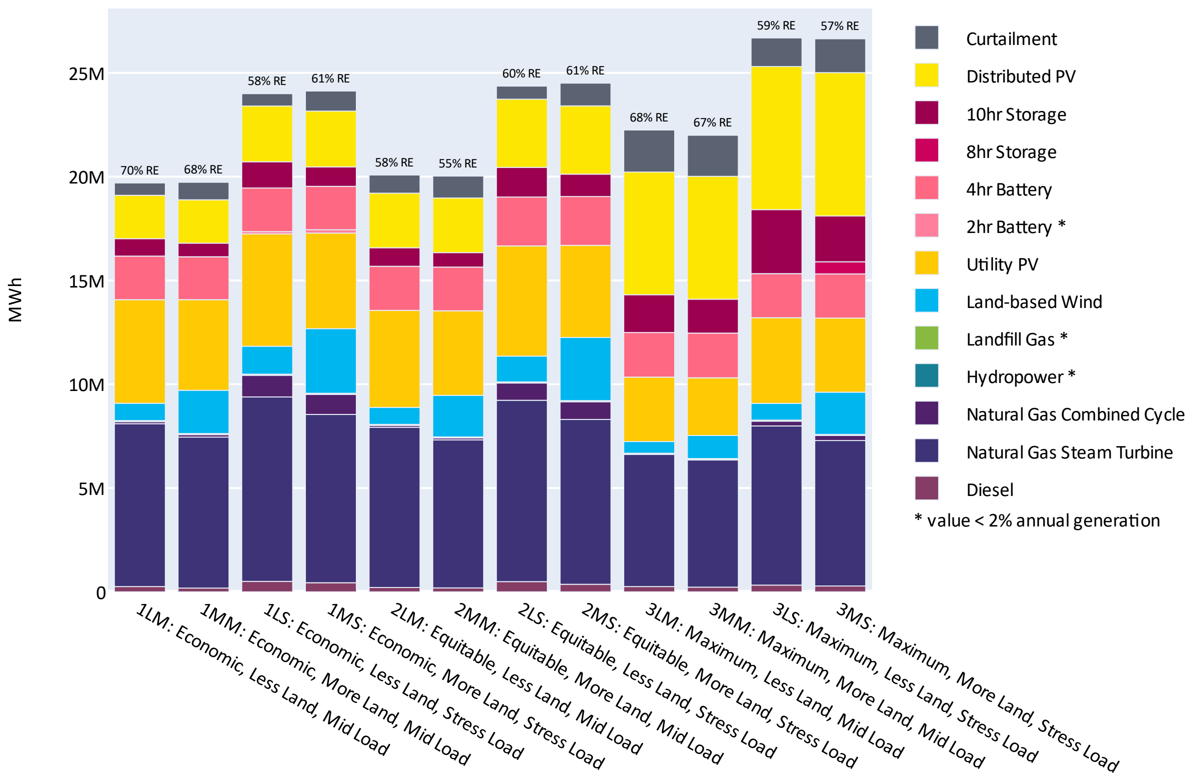


Figure H-3. Total annual electricity generation, by scenario, 2035

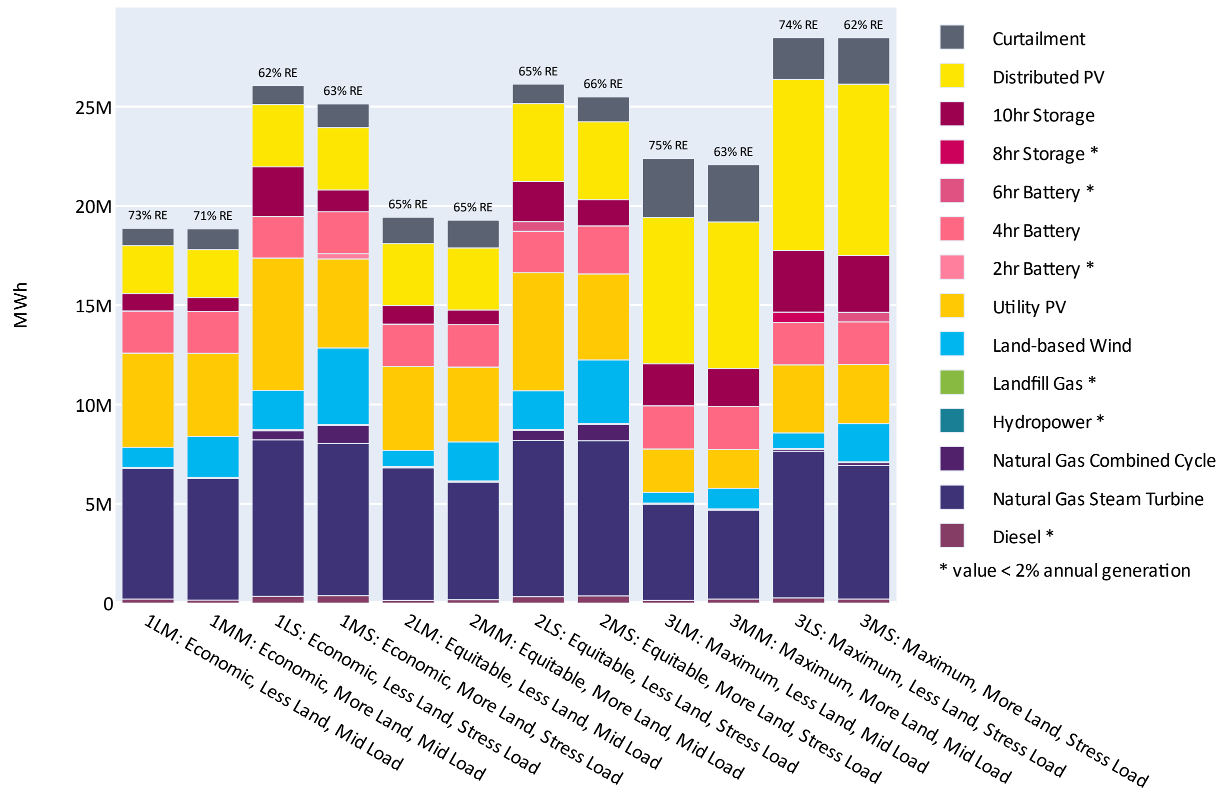


Figure H-4. Total annual electricity generation, by scenario, 2040

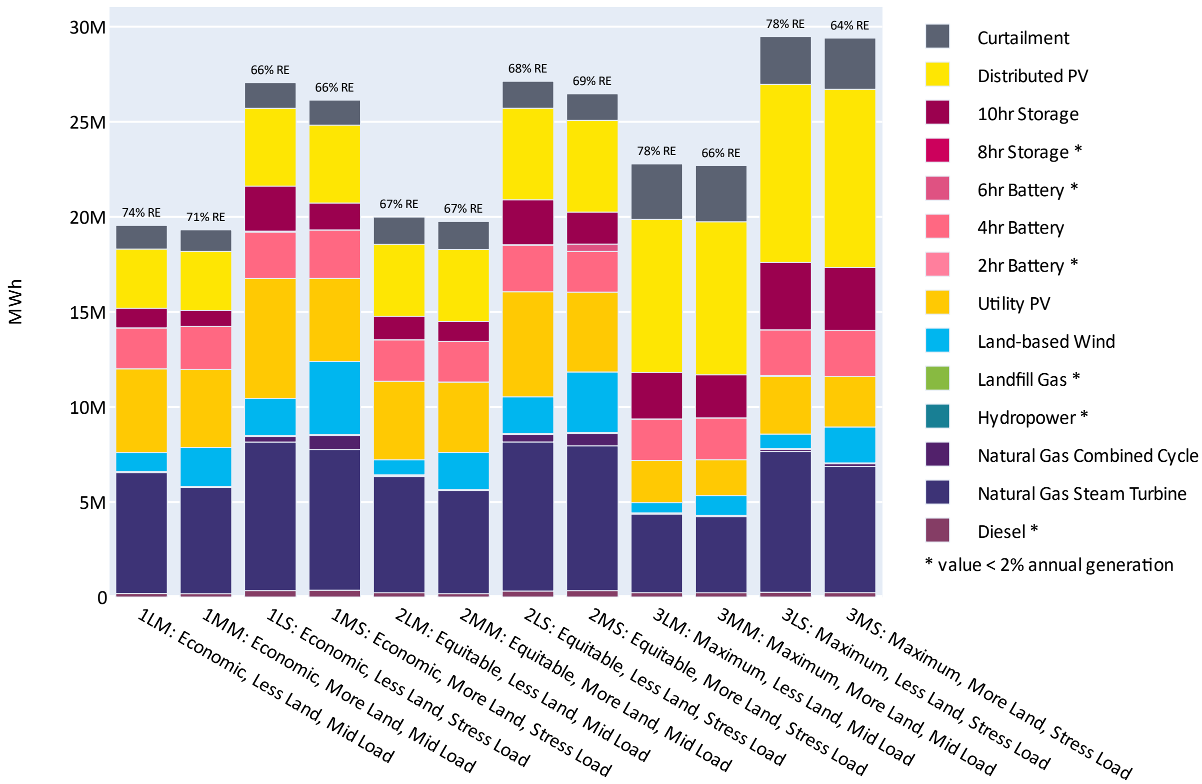


Figure H-5. Total annual electricity generation, by scenario, 2045

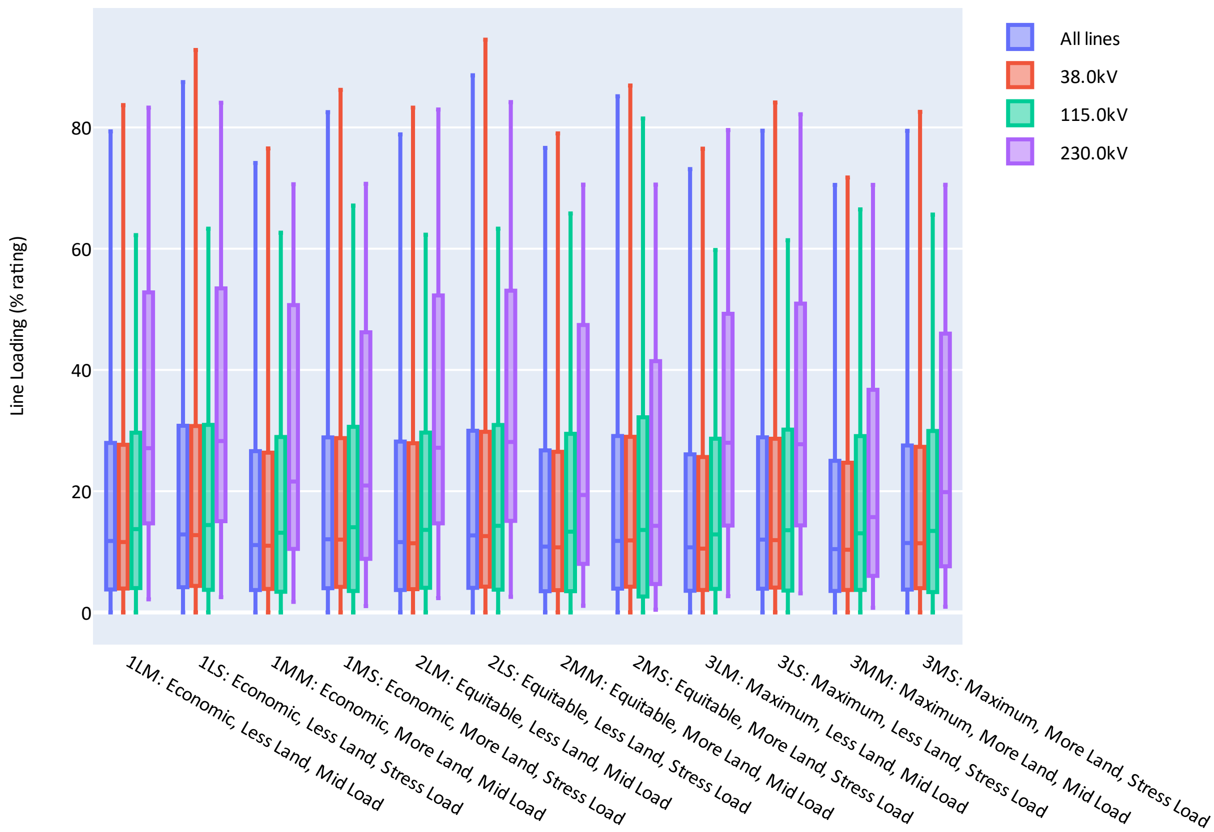


Figure H-6. Distribution of transmission line loading in all periods of 2028, by scenario

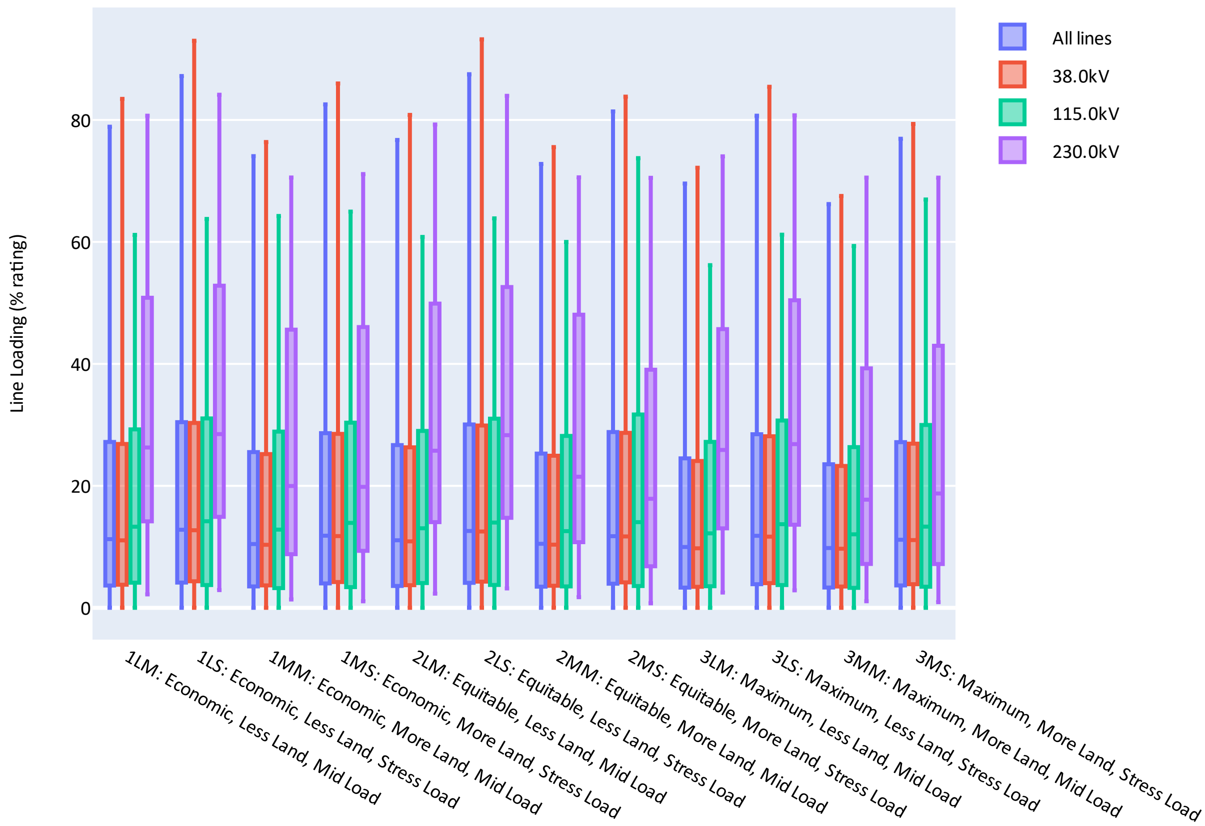


Figure H-7. Distribution of transmission line loading in all periods of 2030, by scenario

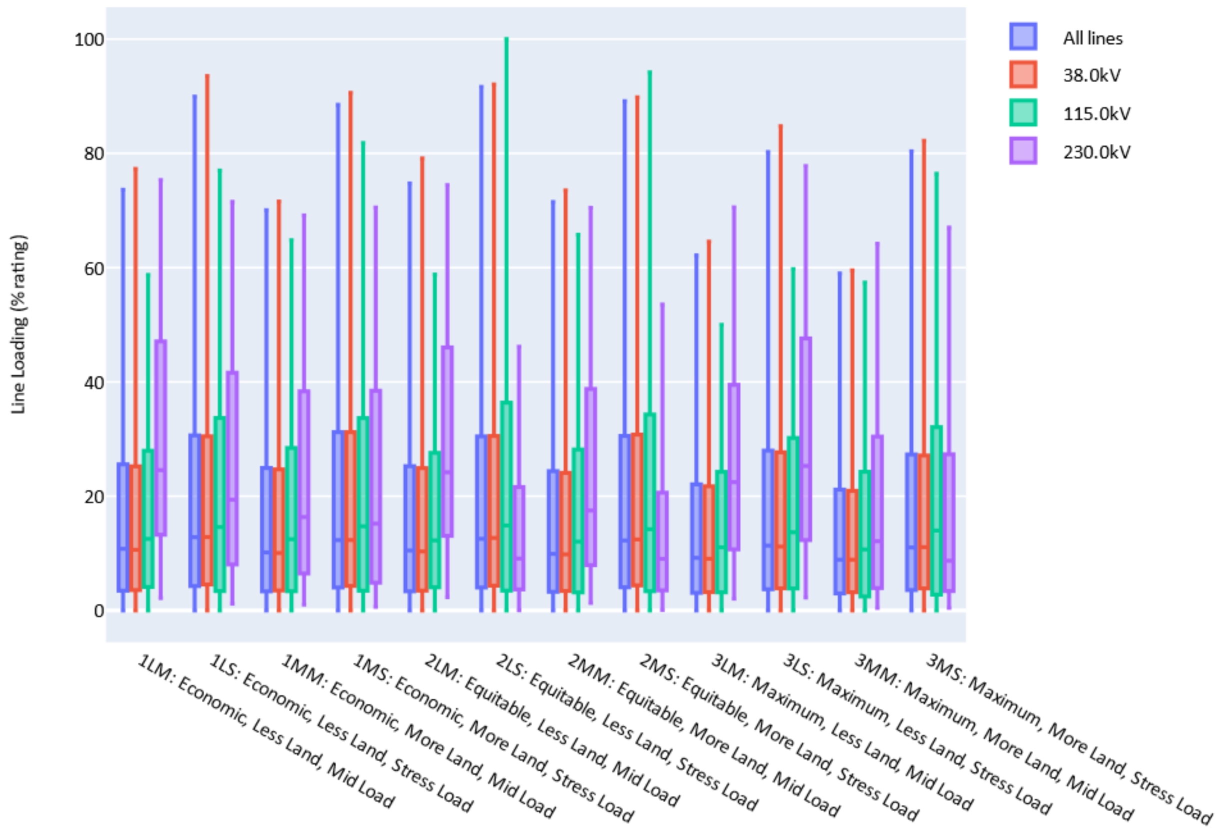


Figure H-8. Distribution of transmission line loading in all periods of 2035, by scenario

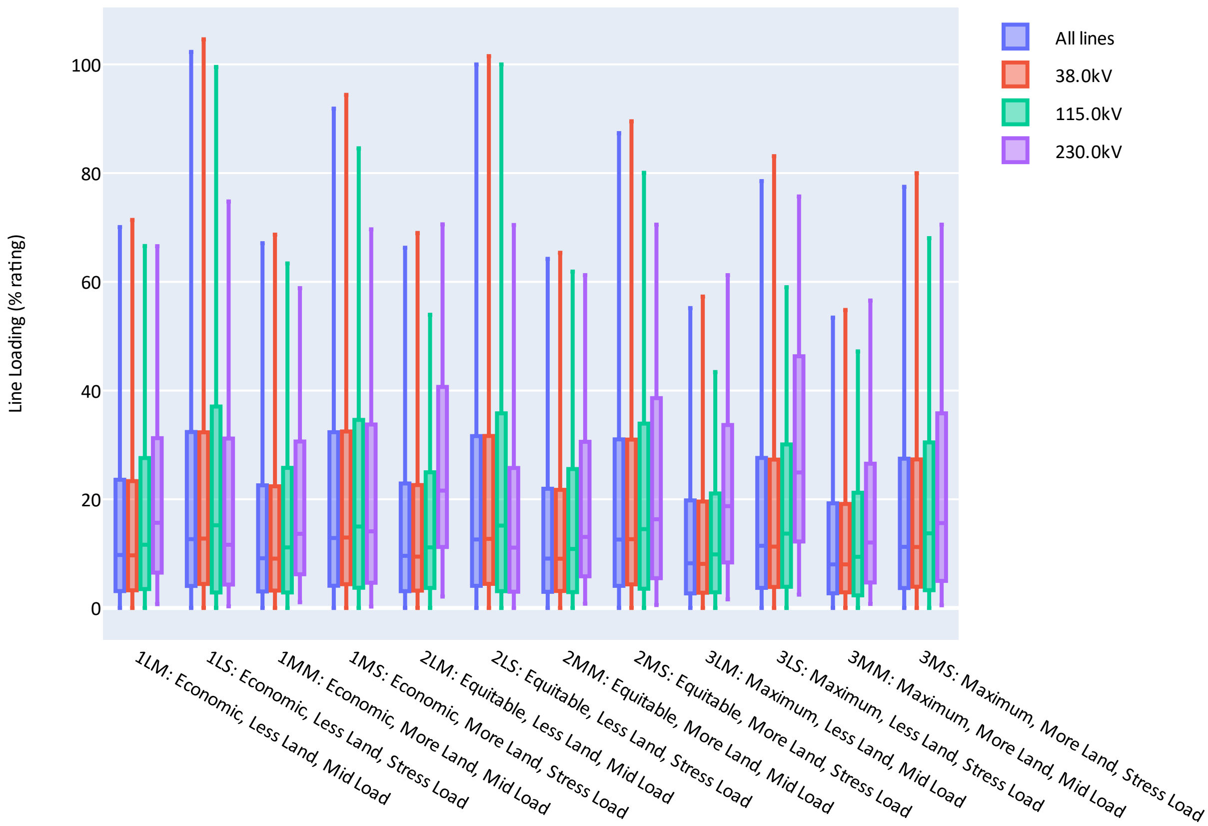


Figure H-9. Distribution of transmission line loading in all periods of 2040, by scenario

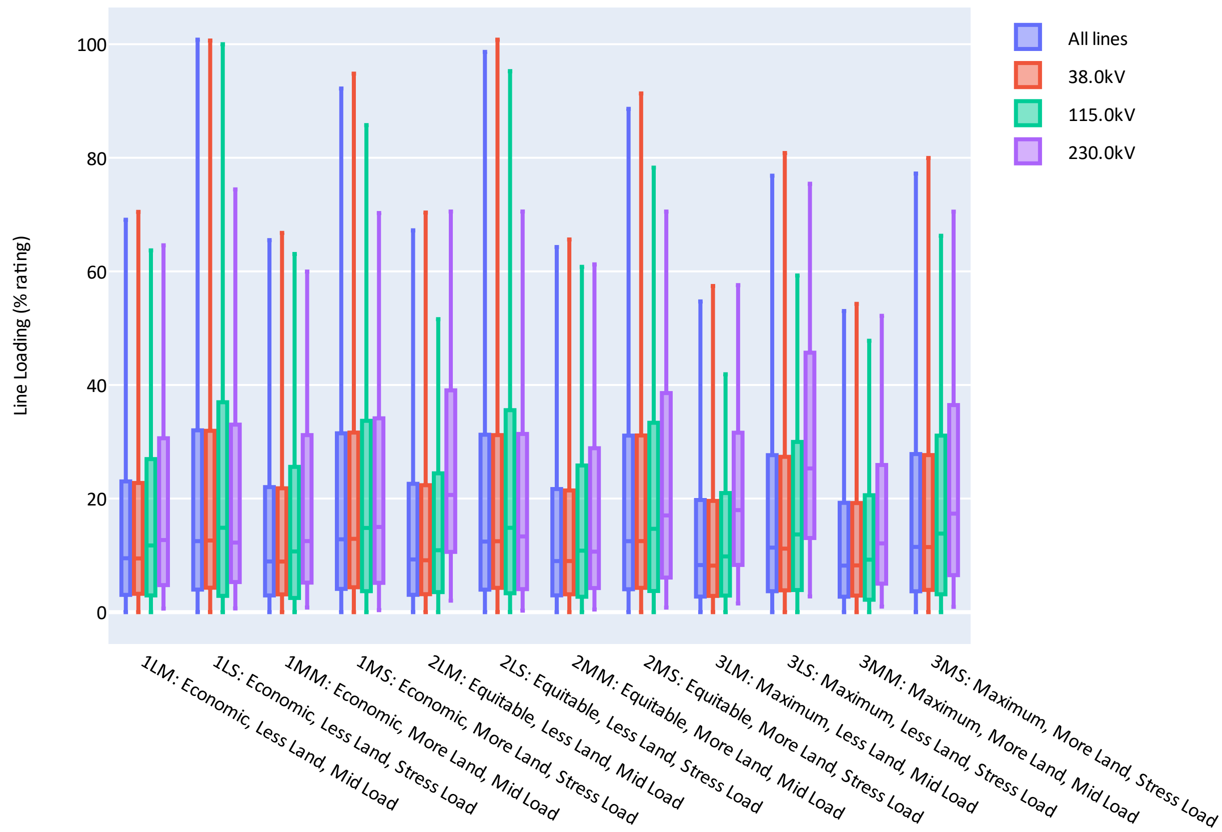


Figure H-10. Distribution of transmission line loading in all periods of 2045, by scenario

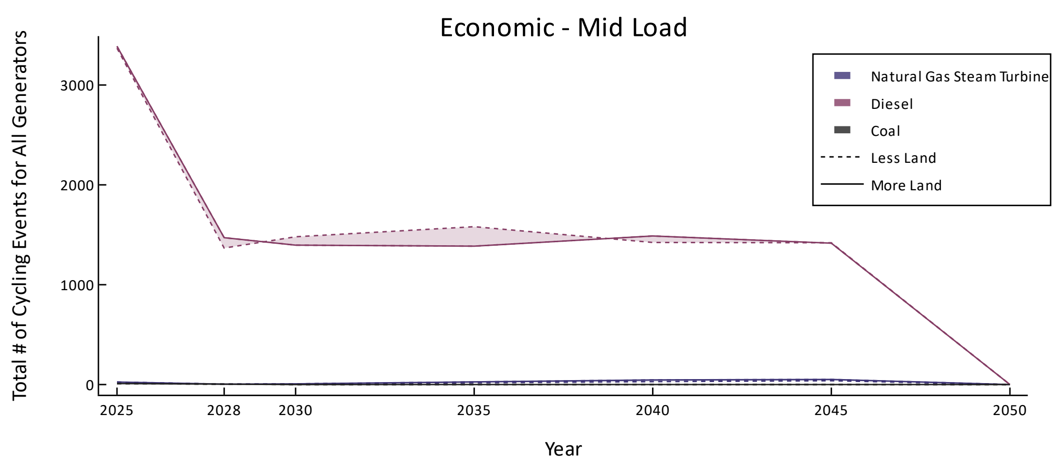


Figure H-11. Fossil-fueled generator cycling for Economic Adoption scenarios under the Mid Load variation (1*M)

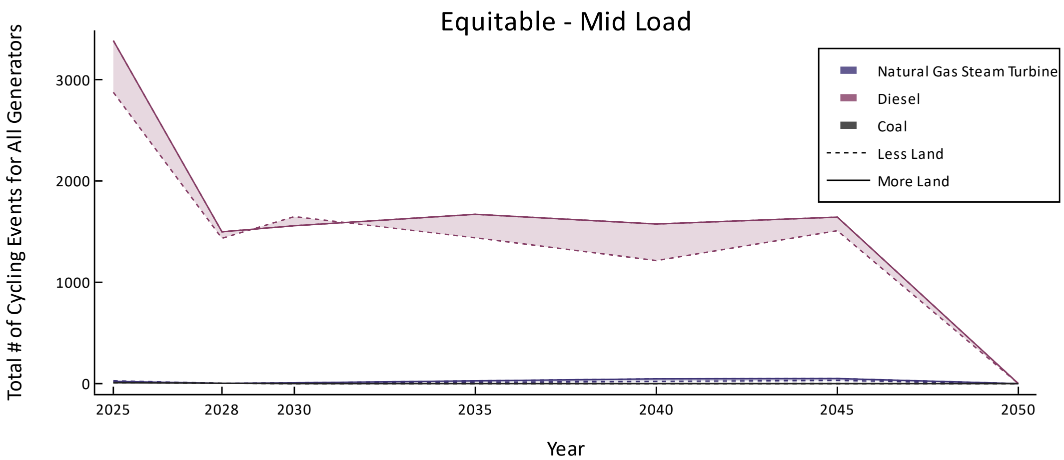


Figure H-12. Fossil-fueled generator cycling for Equitable Adoption scenarios under the Mid Load variation (2*M)

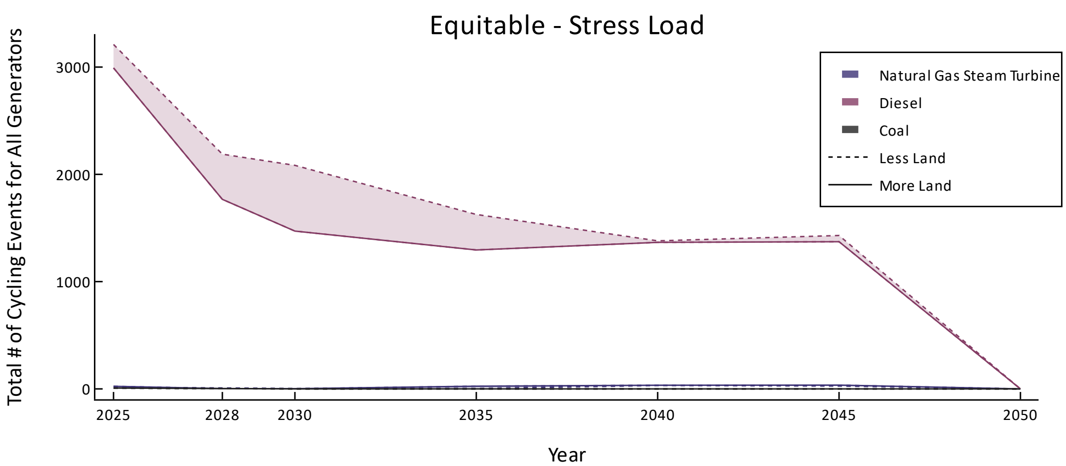


Figure H-13. Fossil-fueled generator cycling for Equitable Adoption scenarios under the Stress Load variation (2*S)

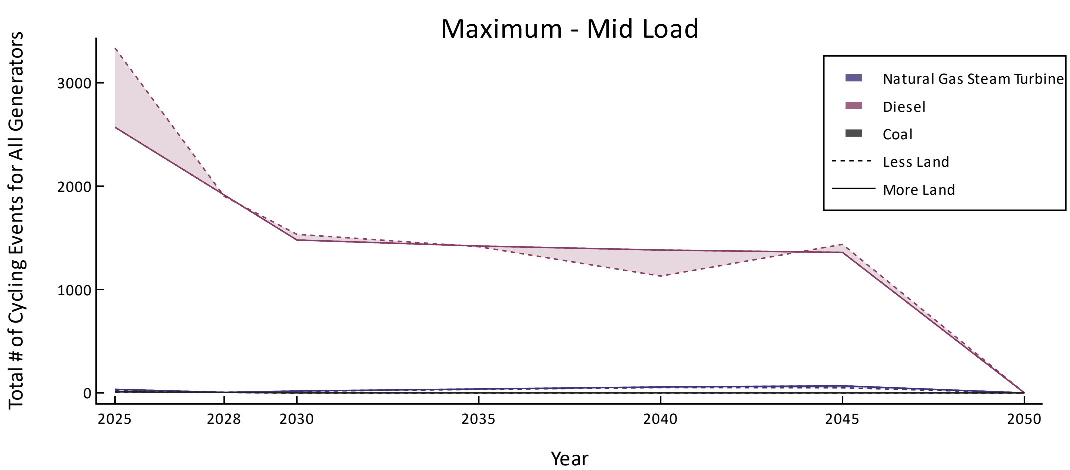


Figure H-14. Fossil-fueled generator cycling for Maximum Adoption scenarios under the Mid Load variation (3*M)

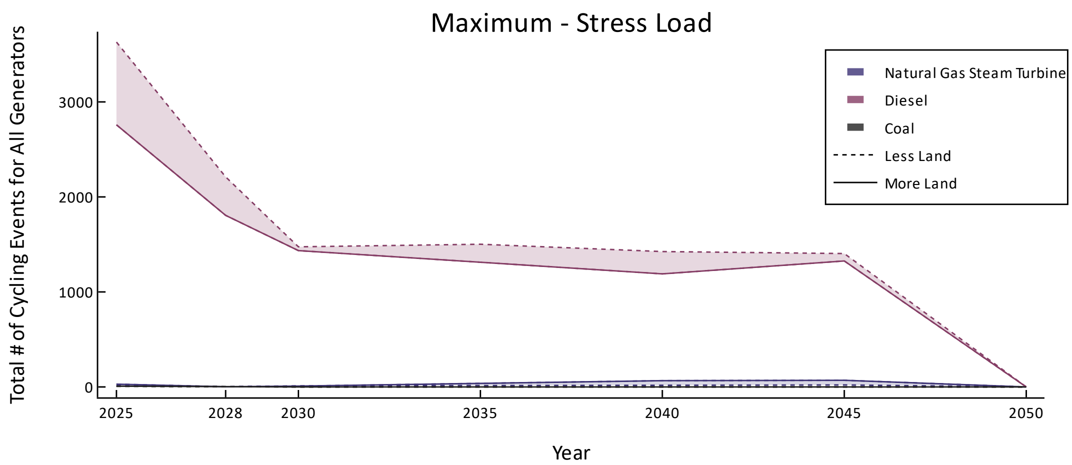


Figure H-15. Fossil-fueled generator cycling for Maximum Adoption scenarios under the Stress Load variation (3*S)

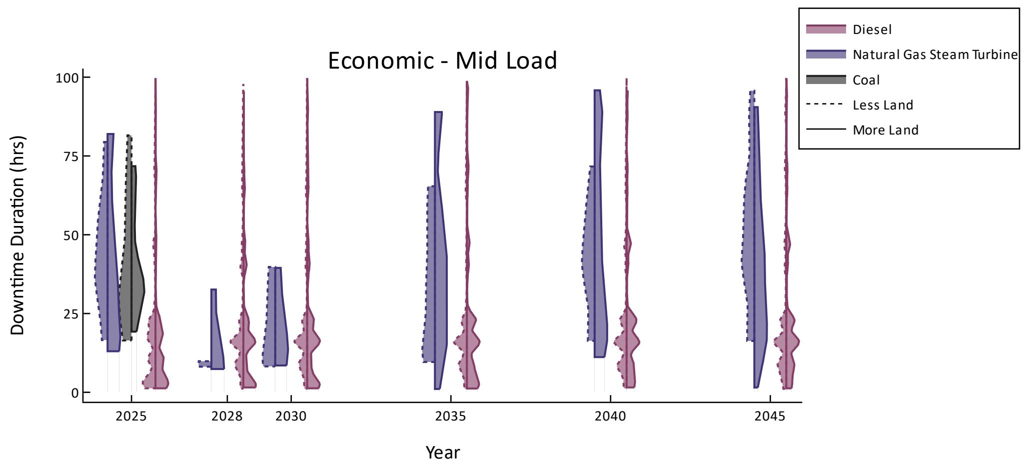


Figure H-16. Fossil-fueled generator downtime duration for Economic Adoption scenarios under the Mid Load variation (1*M)

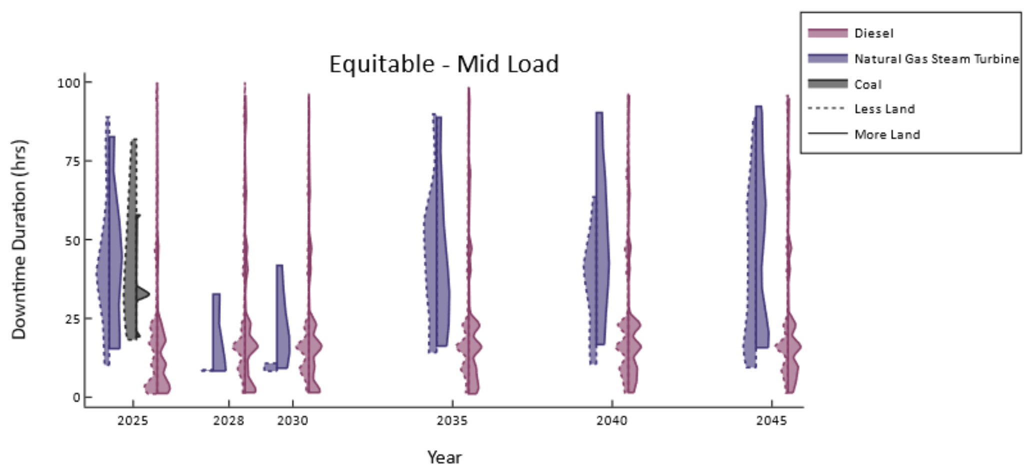


Figure H-17. Fossil-fueled generator downtime duration for Equitable Adoption scenarios under the Mid Load variation (2*M)

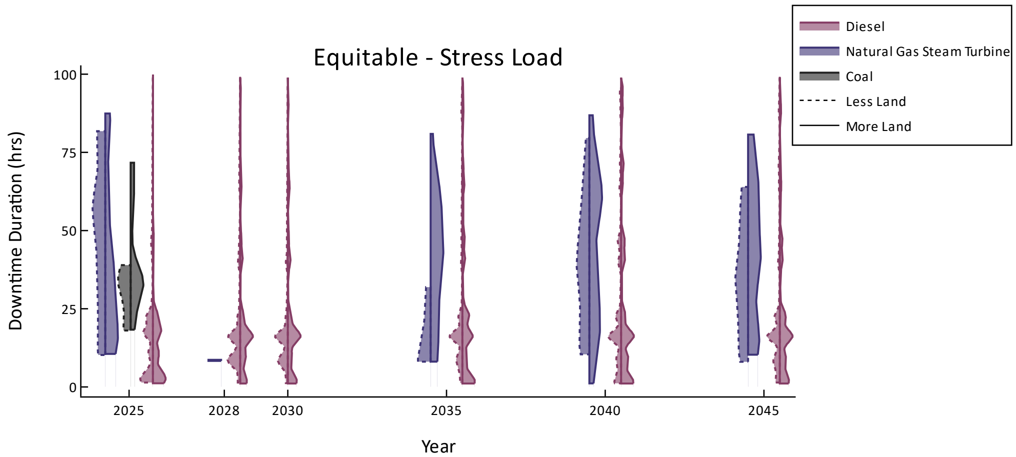


Figure H-18. Fossil-fueled generator downtime duration for Equitable Adoption scenarios under the Stress Load variation (2*S)

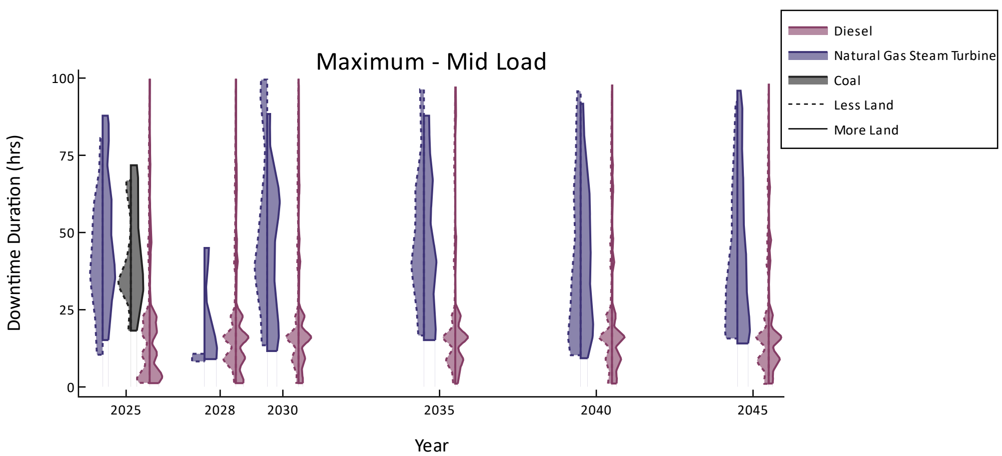


Figure H-19. Fossil-fueled generator downtime duration for Maximum Adoption scenarios under the Mid Load variation (3*M)

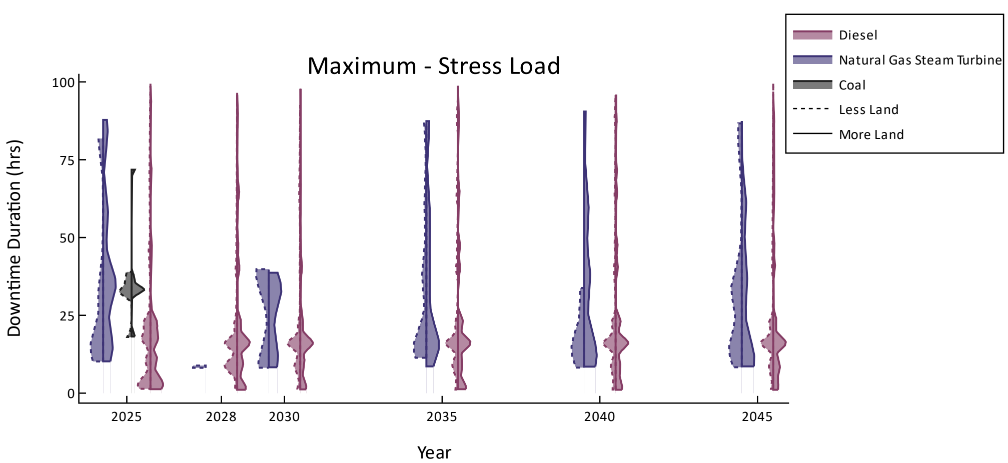


Figure H-20. Fossil-fueled generator downtime duration for Maximum Adoption scenarios under the Stress Load variation (3*S)

Appendix I. JEDI Estimates for Each Scenario by Technology and Interval

Table I-1. 1LM: Average Annual Economic Impacts During Construction and Installation, 2023–2050

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Overall Average
Total jobs	7,125	509	391	374	428	2,264	1,848
Earnings ($ million)	$350	$26	$19	$18	$22	$110	$91
Output ($ million)	$593	$44	$34	$32	$37	$188	$154
Value added ($ million)	$413	$29	$23	$22	$24	$133	$107

Table I-2. 3LS: Average Annual Economic Impacts During Construction and Installation, 2023–2050

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Overall Average
Total jobs	8,694	3,438	1,900	1,312	429	2,585	3,060
Earnings ($ million)	$430	$176	$97	$67	$22	$124	$153
Output ($ million)	$727	$294	$163	$112	$37	$215	$258
Value added ($ million)	$502	$196	$109	$75	$25	$153	$177

Table I-3. 1LM: Average Annual Economic Impacts During O&M, 2023–2050

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Overall Average
Total jobs	265	279	292	305	319	422	314
Earnings ($ million)	$11	$11	$12	$13	$13	$17	$13
Output ($ million)	$23	$24	$25	$27	$27	$38	$27
Value added ($ million)	$15	$16	$17	$18	$19	$25	$18

Table I-4. 3LS: Average Annual Economic Impacts During O&M, 2023–2050

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Overall Average
Total jobs	307	400	455	493	507	629	465
Earnings ($ million)	$12	$16	$18	$19	$20	$25	$18
Output ($ million)	$25	$30	$34	$36	$37	$50	$35
Value added ($ million)	$17	$21	$24	$26	$26	$36	$25

Data outputs for jobs and economic impact analysis of scenarios not discussed in the main body of Section 12.2 (page 447) are contained in the following tables. Construction and installation figures are averaged annual totals from the yearly intervals. O&M figures are cumulatively averaged within their intervals. Construction and installation numbers reflect all economics impacts within their given interval and O&M are cumulative.

Table I-5. Scenario 1LM: Average Annual Jobs for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based Wind	506	0	131	148	0	369
Nonresidential distributed PV	363	74	36	39	75	106
Residential distributed PV	2,547	435	224	186	353	472
Utility PV	3,708	0	0	0	0	1,317

Table I-6. Scenario 1LM: Average Annual Earnings for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$71	$0	$31	$35	$0	$86
Nonresidential distributed PV	$55	$19	$9	$10	$19	$27
Residential distributed PV	$391	$111	$57	$48	$90	$121
Utility PV	$532	$0	$0	$0	$0	$315

Table I-7. Scenario 1LM: Average Annual Output for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$132	$0	$57	$64	$0	$160
Nonresidential distributed PV	$94	$32	$15	$17	$32	$46
Residential distributed PV	$653	$186	$96	$80	$151	$202
Utility PV	$899	$0	$0	$0	$0	$532

Table I-8. Scenario 1LM: Average Annual Value Added for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$96	$0	$42	$47	$0	$117
Nonresidential distributed PV	$63	$21	$10	$11	$22	$31
Residential distributed PV	$436	$124	$64	$53	$101	$135
Utility PV	$643	$0	$0	$0	$0	$381

Table I-9. Scenario 1LM: Average Annual Jobs for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	25	25	30	36	36	52
Nonresidential distributed PV	13	16	17	19	22	27
Residential distributed PV	66	78	84	89	99	113
Utility PV	161	161	161	161	161	230

Table I-10. Scenario 1LM: Average Annual Earnings for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$1.1	$1.1	$1.5	$1.8	$1.8	$3.0
Nonresidential distributed PV	$0.5	$0.6	$0.7	$0.7	$0.9	$1.2
Residential distributed PV	$2.4	$2.9	$3.2	$3.5	$4.0	$4.9
Utility PV	$6.9	$6.9	$6.9	$6.9	$6.9	$11.9

Table I-11. Scenario 1LM: Average Annual Output for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$4.6	$4.6	$6.0	$7.7	$7.7	$12.9
Nonresidential distributed PV	$0.7	$0.9	$1.0	$1.1	$1.3	$1.7
Residential distributed PV	$3.7	$4.4	$4.9	$5.3	$6.1	$7.4
Utility PV	$13.8	$13.8	$13.8	$13.8	$13.8	$23.8

Table I-12. Scenario 1LM: Average Annual Value Added for Each Interval during O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$3.9	$3.9	$5.1	$6.5	$6.5	$10.9
Nonresidential distributed PV	$0.6	$0.7	$0.8	$0.9	$1.1	$1.4
Residential distributed PV	$2.9	$3.5	$3.8	$4.1	$4.8	$5.8
Utility PV	$7.6	$7.6	$7.6	$7.6	$7.6	$13.1

Table I-13. Scenario 1LS: Average Annual Jobs for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	507	0	516	533	0	1,470
Nonresidential distributed PV	424	88	43	47	89	126
Residential distributed PV	3,164	626	319	269	509	682
Utility PV	3,954	0	0	330	0	1,290

Table I-14. Scenario 1LS: Average Annual Earnings for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$71	$0	$121	$125	$0	$344
Nonresidential distributed PV	$64	$22	$11	$12	$23	$32
Residential distributed PV	$486	$160	$82	$69	$130	$174
Utility PV	$567	$0	$0	$79	$0	$308

Table I-15. Scenario 1LS: Average Annual Output for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$132	$0	$224	$232	$0	$639
Nonresidential distributed PV	$110	$38	$18	$20	$38	$54
Residential distributed PV	$811	$267	$136	$115	$218	$291
Utility PV	$958	$0	$0	$133	$0	$521

Table I-16. Scenario 1LS: Average Annual Value Added for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$97	$0	$164	$169	$0	$467
Nonresidential distributed PV	$73	$25	$12	$13	$26	$36
Residential distributed PV	$541	$178	$91	$77	$145	$194
Utility PV	$686	$0	$0	$95	$0	$373

Table I-17. Scenario 1LS: Average Annual Jobs for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	25	25	46	68	68	129
Nonresidential distributed PV	15	19	20	22	26	31
Residential distributed PV	82	99	108	115	130	150
Utility PV	171	171	171	188	188	255

Table I-18. Scenario 1LS: Average Annual Earnings for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$1.1	$1.1	$2.4	$3.7	$3.7	$8.3
Nonresidential distributed PV	$0.6	$0.7	$0.8	$0.9	$1.1	$1.4
Residential distributed PV	$3.0	$3.7	$4.1	$4.5	$5.4	$6.6
Utility PV	$7.4	$7.4	$7.4	$8.3	$8.3	$13.1

Table I-19. Scenario 1LS: Average Annual Output for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$4.6	$4.6	$10.1	$16.2	$16.2	$36.8
Nonresidential distributed PV	$0.8	$1.0	$1.1	$1.3	$1.5	$2.0
Residential distributed PV	$4.6	$5.6	$6.3	$6.9	$8.1	$10.0
Utility PV	$14.8	$14.8	$14.8	$16.7	$16.7	$26.3

Table I-20. Scenario 1LS: Average Annual Value Added for Each Interval during O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$3.9	$3.9	$8.5	$13.7	$13.7	$31.1
Nonresidential distributed PV	$0.7	$0.8	$0.9	$1.0	$1.3	$1.6
Residential distributed PV	$3.6	$4.4	$4.9	$5.4	$6.3	$7.8
Utility PV	$8.1	$8.1	$8.1	$9.2	$9.2	$14.4

Table I-21. Scenario 1MS: Average Annual Jobs for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	1,179	0	1,169	515	0	1,176
Nonresidential distributed PV	363	74	36	39	75	106
Residential distributed PV	2,547	435	224	186	353	472
Utility PV	3,465	0	0	0	0	1,331

Table I-22. Scenario 1MS: Average Annual Earnings for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$165	$0	$273	$120	$0	$275
Nonresidential distributed PV	$55	$19	$9	$10	$19	$27
Residential distributed PV	$391	$111	$57	$48	$90	$121
Utility PV	$497	$0	$0	$0	$0	$318

Table I-23. Scenario 1MS: Average Annual Output for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$308	$0	$508	$224	$0	$511
Nonresidential distributed PV	$94	$32	$15	$17	$32	$46
Residential distributed PV	$653	$186	$96	$80	$151	$202
Utility PV	$840	$0	$0	$0	$0	$538

Table I-24. Scenario 1MS: Average Annual Value Added for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$225	$0	$371	$163	$0	$373
Nonresidential distributed PV	$63	$21	$10	$11	$22	$31
Residential distributed PV	$436	$124	$64	$53	$101	$135
Utility PV	$601	$0	$0	$0	$0	$385

Table I-25. Scenario 1MS: Average Annual Jobs for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	63	63	115	138	138	190
Nonresidential distributed PV	13	16	17	19	22	27
Residential distributed PV	66	78	84	89	99	113
Utility PV	152	152	152	152	152	226

Table I-26. Scenario 1MS: Average Annual Earnings for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$2.9	$2.9	$5.9	$7.3	$7.3	$11.3
Nonresidential distributed PV	$0.5	$0.6	$0.7	$0.7	$0.9	$1.2
Residential distributed PV	$2.4	$2.9	$3.2	$3.5	$4.0	$4.9
Utility PV	$6.5	$6.5	$6.5	$6.5	$6.5	$11.8

Table I-27. Scenario 1MS: Average Annual Output for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$11.3	$11.3	$24.2	$30.5	$30.5	$47.6
Nonresidential distributed PV	$0.7	$0.9	$1.0	$1.1	$1.3	$1.7
Residential distributed PV	$3.7	$4.4	$4.9	$5.3	$6.1	$7.4
Utility PV	$13.1	$13.1	$13.1	$13.1	$13.1	$23.7

Table I-28. Scenario 1MS: Average Annual Value Added for Each Interval during O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$9.5	$9.5	$20.4	$25.7	$25.7	$40.1
Nonresidential distributed PV	$0.6	$0.7	$0.8	$0.9	$1.1	$1.4
Residential distributed PV	$2.9	$3.5	$3.8	$4.1	$4.8	$5.8
Utility PV	$7.2	$7.2	$7.2	$7.2	$7.2	$13.0

Table I-29. Scenario 2LS: Average Annual Jobs for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	507	0	441	593	0	1,239
Nonresidential distributed PV	424	88	43	47	89	126
Residential distributed PV	3,322	1,153	587	455	465	579
Utility PV	3,918	0	0	187	0	1,437

Table I-30. Scenario 2LS: Average Annual Earnings for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$71	$0	$103	$139	$0	$290
Nonresidential distributed PV	$64	$22	$11	$12	$23	$32
Residential distributed PV	$510	$295	$150	$116	$119	$148
Utility PV	$562	$0	$0	$45	$0	$343

Table I-31. Scenario 2LS: Average Annual Output for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$132	$0	$192	$258	$0	$538
Nonresidential distributed PV	$110	$38	$18	$20	$38	$54
Residential distributed PV	$852	$493	$251	$194	$199	$247
Utility PV	$950	$0	$0	$76	$0	$581

Table I-32. Scenario 2LS: Average Annual Value Added for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$97	$0	$140	$188	$0	$393
Nonresidential distributed PV	$73	$25	$12	$13	$26	$36
Residential distributed PV	$568	$329	$167	$130	$132	$165
Utility PV	$679	$0	$0	$54	$0	$415

Table I-33. Scenario 2LS: Average Annual Jobs for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	25	25	43	67	67	119
Nonresidential distributed PV	15	19	20	22	26	31
Residential distributed PV	86	117	133	146	159	177
Utility PV	170	170	170	179	179	254

Table I-34. Scenario 2LS Average Annual Earnings for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$1.1	$1.1	$2.2	$3.7	$3.7	$7.6
Nonresidential distributed PV	$0.6	$0.7	$0.8	$0.9	$1.1	$1.4
Residential distributed PV	$3.2	$4.5	$5.2	$5.9	$6.6	$7.7
Utility PV	$7.3	$7.3	$7.3	$7.8	$7.8	$13.2

Table I-35. Scenario 2LS: Average Annual Output for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$4.6	$4.6	$9.3	$16.1	$16.1	$33.4
Nonresidential distributed PV	$0.8	$1.0	$1.1	$1.3	$1.5	$2.0
Residential distributed PV	$4.8	$6.8	$7.9	$8.9	$10.1	$11.6
Utility PV	$14.6	$14.6	$14.6	$15.7	$15.7	$26.5

Table I-36. Scenario 2LS: Average Annual Value Added for Each Interval during O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$3.9	$3.9	$7.8	$13.7	$13.7	$28.3
Nonresidential distributed PV	$0.7	$0.8	$0.9	$1.0	$1.3	$1.6
Residential distributed PV	$3.7	$5.3	$6.2	$7.0	$7.9	$9.1
Utility PV	$8.0	$8.0	$8.0	$8.6	$8.6	$14.5

Table I-37. Scenario 3LS: Average Annual Jobs for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	507	0	142	0	0	722
Nonresidential distributed PV	629	130	64	69	131	186
Residential distributed PV	3,937	3,308	1,694	1,243	298	181
Utility PV	3,621	0	0	0	0	1,495

Table I-38. Scenario 3LS: Average Annual Earnings for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$71	$0	$33	$0	$0	$169
Nonresidential distributed PV	$96	$33	$16	$18	$33	$47
Residential distributed PV	$604	$846	$433	$318	$76	$46
Utility PV	$519	$0	$0	$0	$0	$357

Table I-39. Scenario 3LS: Average Annual Output for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$132	$0	$62	$0	$0	$314
Nonresidential distributed PV	$163	$56	$28	$30	$57	$80
Residential distributed PV	$1,009	$1,414	$724	$531	$127	$77
Utility PV	$878	$0	$0	$0	$0	$604

Table I-40. Scenario 3LS: Average Annual Value Added for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$97	$0	$45	$0	$0	$229
Nonresidential distributed PV	$109	$38	$19	$20	$38	$54
Residential distributed PV	$673	$943	$483	$354	$85	$52
Utility PV	$628	$0	$0	$0	$0	$432

Table I-41. Scenario 3LS: Average Annual Jobs for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	25	25	31	31	31	61
Nonresidential distributed PV	23	28	30	33	39	47
Residential distributed PV	102	190	237	272	281	286
Utility PV	157	157	157	157	157	236

Table I-42. Scenario 3LS: Average Annual Earnings for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$1.1	$1.1	$1.5	$1.5	$1.5	$3.8
Nonresidential distributed PV	$0.8	$1.0	$1.2	$1.3	$1.6	$2.1
Residential distributed PV	$3.8	$7.5	$9.7	$11.5	$12.0	$12.3
Utility PV	$6.7	$6.7	$6.7	$6.7	$6.7	$12.4

Table I-43. Scenario 3LS: Average Annual Output for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$4.6	$4.6	$6.1	$6.1	$6.1	$16.2
Nonresidential distributed PV	$1.2	$1.5	$1.7	$1.9	$2.2	$2.9
Residential distributed PV	$5.7	$11.4	$14.7	$17.4	$18.1	$18.6
Utility PV	$13.5	$13.5	$13.5	$13.5	$13.5	$24.8

Table I-44. Scenario 3LS: Average Annual Value Added for Each Interval during O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$3.9	$3.9	$5.2	$5.2	$5.2	$13.7
Nonresidential distributed PV	$1.0	$1.2	$1.3	$1.5	$1.9	$2.4
Residential distributed PV	$4.4	$8.9	$11.5	$13.6	$14.2	$14.6
Utility PV	$7.4	$7.4	$7.4	$7.4	$7.4	$13.6

Table I-45. Scenario 3MM: Average Annual Jobs for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	1,172	0	45	0	0	775
Nonresidential distributed PV	565	117	58	62	118	167
Residential distributed PV	3,377	2,814	1,442	1,058	253	154
Utility PV	2,908	0	0	0	0	388

Table I-46. Scenario 3MM: Average Annual Earnings for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$164	$0	$10	$0	$0	$181
Nonresidential distributed PV	$86	$30	$15	$16	$30	$42
Residential distributed PV	$518	$720	$369	$271	$65	$39
Utility PV	$417	$0	$0	$0	$0	$93

Table I-47. Scenario 3MM: Average Annual Output for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$306	$0	$19	$0	$0	$337
Nonresidential distributed PV	$146	$50	$25	$27	$51	$72
Residential distributed PV	$866	$1,203	$616	$452	$108	$66
Utility PV	$705	$0	$0	$0	$0	$157

Table I-48. Scenario 3MM: Average Annual Value Added for Each Interval During Construction, by Technology

Construction Phase	2023–2025	2026–2030	2031–2035	2036-2040	2041–2045	2046–2050
Land-based wind	$223	$0	$14	$0	$0	$246
Nonresidential distributed PV	$98	$34	$17	$18	$34	$48
Residential distributed PV	$578	$802	$411	$301	$72	$44
Utility PV	$504	$0	$0	$0	$0	$112

Table I-49. Scenario 3MM: Average Annual Jobs for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	63	63	65	65	65	99
Nonresidential distributed PV	21	25	27	30	35	42
Residential distributed PV	20	95	134	164	172	176
Utility PV	127	127	127	127	127	149

Table I-50. Scenario 3MM: Average Annual Earnings for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$2.9	$2.9	$3.0	$3.0	$3.0	$5.6
Nonresidential distributed PV	$0.7	$0.9	$1.0	$1.2	$1.4	$1.9
Residential distributed PV	$0.7	$4.0	$5.8	$7.3	$7.7	$8.0
Utility PV	$5.5	$5.5	$5.5	$5.5	$5.5	$7.0

Table I-51. Scenario 3MM: Average Annual Output for Each Interval During O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$11.2	$11.2	$11.7	$11.7	$11.7	$22.9
Nonresidential distributed PV	$1.1	$1.4	$1.5	$1.7	$2.0	$2.6
Residential distributed PV	$1.1	$6.0	$8.8	$11.1	$11.7	$12.1
Utility PV	$10.9	$10.9	$10.9	$10.9	$10.9	$14.0

Table I-52. Scenario 3MM: Average Annual Value Added for Each Interval during O&M, by Technology

O&M Phase	2023–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050
Land-based wind	$9.4	$9.4	$9.9	$9.9	$9.9	$19.3
Nonresidential distributed PV	$0.9	$1.1	$1.2	$1.4	$1.7	$2.2
Residential distributed PV	$0.9	$4.7	$6.9	$8.7	$9.2	$9.5
Utility PV	$6.0	$6.0	$6.0	$6.0	$6.0	$7.7

Appendix J. Computable General Equilibrium Results

J.1 Impacts of 1LS Scenario

Table J-1. Puerto Rico Municipalities by Region

Region	Municipality
Central	Adjuntas, Aibonito, Barranquitas, Ciales, Comerío, Corozal, Jayuya, Lares, Las Marías, Maricao, Morovis, Naranjito, Orocovis, San Sebastián, and Utuado
East	Aguas Buenas, Caguas, Cayey, Ceiba, Cidra, Culebra, Fajardo, Gurabo, Humacao, Juncos, Las Piedras, Naguabo, San Lorenzo, Vieques, and Yabucoa
Metro	Bayamón, Canóvanas, Carolina, Cataño, Dorado, Guaynabo, Loíza, Luquillo, Río Grande, San Juan, Toa Baja, and Trujillo Alto
North	Arecibo, Barceloneta, Camuy, Florida, Hatillo, Manatí, Toa Alta, Vega Alta, and Vega Baja
South	Arroyo, Coamo, Guánica, Guayama, Guayanilla, Juana Díaz, Maunabo, Patillas, Peñuelas, Ponce, Salinas, Santa Isabel, Villalba, and Yauco
West	Añasco, Aguada, Aguadilla, Cabo Rojo, Hormigueros, Isabela, Lajas, Mayagüez, Moca, Quebradillas, Rincón, Sabana Grande, and San Germán

Table J-2. Changes in Real Household Income (millions of dollars), by Region

Region	2025		2028		2030		2035		2040		2045		2050	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
Metro	-332.7	-2.87%	46.8	0.40%	17.6	0.15%	19.7	0.17%	63.8	0.55%	20.9	0.18%	658.1	5.68%
East	-175.4	-3.81%	50.5	1.10%	7.4	0.16%	6.8	0.15%	27.4	0.59%	8.2	0.18%	105.2	2.28%
West	-23.2	-0.91%	13.2	0.51%	5.8	0.23%	18.8	0.73%	19.8	0.77%	6.8	0.27%	97.8	3.82%
North	-102.1	-3.51%	24.2	0.83%	4.4	0.15%	5.2	0.18%	24.0	0.82%	5.9	0.20%	68.6	2.36%
South	3.7	0.13%	24.5	0.87%	5.9	0.21%	13.3	0.47%	33.5	1.19%	7.4	0.26%	96.0	3.40%
Central	-94.8	-4.97%	6.4	0.33%	0.7	0.04%	3.7	0.20%	11.9	0.62%	1.1	0.06%	33.7	1.77%
Total	-724.6	-2.75%	165.6	0.63%	41.8	0.16%	67.5	0.26%	180.4	0.68%	50.3	0.19%	1,059.4	4.01%

Table J-3. Changes in Employment, by Region

Region	2025		2028		2030		2035		2040		2045		2050	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
Metro	-1,203	-0.32%	1,616	0.43%	293	0.08%	916	0.24%	1,616	0.43%	390	0.10%	1,065	0.28%
East	-2,060	-1.19%	-22	-0.01%	67	0.04%	363	0.21%	674	0.39%	101	0.06%	2,485	1.43%
West	-1,664	-1.43%	420	0.36%	26	0.02%	-109	-0.09%	360	0.31%	41	0.04%	1,118	0.96%
North	-2,237	-1.85%	187	0.15%	79	0.07%	269	0.22%	308	0.25%	86	0.07%	1,959	1.62%
South	-4,368	-3.40%	210	0.16%	39	0.03%	50	0.04%	107	0.08%	43	0.03%	1,465	1.14%
Central	-720	-0.83%	412	0.48%	105	0.12%	159	0.18%	353	0.41%	120	0.14%	1,681	1.94%
total	-12,252	-1.22%	2,823	0.28%	609	0.06%	1,650	0.16%	3,419	0.34%	781	0.08%	9,773	0.97%

Table J-4. Distribution of Real Household Income (millions of dollars), 2025

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	0.13	0.13%	-0.08	-0.15%	0.05	0.10%	0.20	0.56%	0.11	0.21%	0.04	0.11%
$10k-$15k	0.15	0.09%	0.05	0.06%	0.28	0.33%	0.22	0.46%	0.49	0.45%	0.08	0.16%
$15k-$25k	1.42	0.22%	1.45	0.42%	1.09	0.39%	1.52	0.56%	2.45	0.73%	0.54	0.25%
$25k-$35k	2.60	0.30%	2.38	0.50%	1.59	0.45%	2.05	0.58%	2.38	0.69%	0.75	0.29%
$35k-$75k	14.95	0.38%	15.34	0.95%	5.30	0.56%	9.71	0.85%	10.24	0.85%	2.81	0.37%
>$75k	27.58	0.47%	31.39	1.53%	4.87	0.58%	10.45	0.98%	8.81	1.13%	2.16	0.37%
Total	46.85	0.40%	50.53	1.10%	13.20	0.51%	24.15	0.83%	24.48	0.87%	6.38	0.33%

Table J-5. Distribution of Real Household Income (millions of dollars), 2028

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	0.13	0.13%	-0.08	-0.15%	0.05	0.10%	0.20	0.56%	0.11	0.21%	0.04	0.11%
$10k-$15k	0.15	0.09%	0.05	0.06%	0.28	0.33%	0.22	0.46%	0.49	0.45%	0.08	0.16%
$15k-$25k	1.42	0.22%	1.45	0.42%	1.09	0.39%	1.52	0.56%	2.45	0.73%	0.54	0.25%
$25k-$35k	2.60	0.30%	2.38	0.50%	1.59	0.45%	2.05	0.58%	2.38	0.69%	0.75	0.29%
$35k-$75k	14.95	0.38%	15.34	0.95%	5.30	0.56%	9.71	0.85%	10.24	0.85%	2.81	0.37%
>$75k	27.58	0.47%	31.39	1.53%	4.87	0.58%	10.45	0.98%	8.81	1.13%	2.16	0.37%
Total	46.85	0.40%	50.53	1.10%	13.20	0.51%	24.15	0.83%	24.48	0.87%	6.38	0.33%

Table J-6. Distribution of Real Household Income (millions of dollars), 2030

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-0.17	-0.17%	-0.19	-0.36%	-0.14	-0.24%	-0.05	-0.14%	-0.11	-0.20%	-0.08	-0.23%
$10k-$15k	-0.23	-0.14%	-0.14	-0.18%	0.04	0.05%	-0.04	-0.08%	-0.01	-0.01%	-0.06	-0.11%
$15k-$25k	-0.08	-0.01%	-0.04	-0.01%	0.31	0.11%	0.09	0.03%	0.45	0.13%	-0.04	-0.02%
$25k-$35k	0.55	0.06%	0.18	0.04%	0.57	0.16%	0.22	0.06%	0.53	0.15%	0.06	0.02%
$35k-$75k	4.38	0.11%	2.32	0.14%	2.31	0.24%	1.76	0.15%	2.30	0.19%	0.33	0.04%
>$75k	13.21	0.23%	5.26	0.26%	2.69	0.32%	2.43	0.23%	2.73	0.35%	0.47	0.08%
Total	17.65	0.15%	7.39	0.16%	5.80	0.23%	4.41	0.15%	5.89	0.21%	0.68	0.04%

Table J-7. Distribution of Real Household Income (millions of dollars), 2035

Household Income	Metro Amount	Metro Percent Change	East Amount	East Percent Change	West Amount	West Percent Change	North Amount	North Percent Change	South Amount	South Percent Change	Central Amount	Central Percent Change
<$10k	-0.24	-0.24%	-0.24	-0.45%	-0.16	-0.28%	-0.08	-0.23%	-0.12	-0.22%	-0.07	-0.20%
$10k-$15k	-0.33	-0.19%	-0.17	-0.21%	0.34	0.40%	-0.06	-0.13%	0.12	0.11%	-0.02	-0.03%
$15k-$25k	-0.21	-0.03%	-0.03	-0.01%	1.46	0.53%	0.07	0.03%	1.20	0.36%	0.27	0.12%
$25k-$35k	0.70	0.08%	0.27	0.06%	1.90	0.54%	0.27	0.08%	1.24	0.36%	0.40	0.16%
$35k-$75k	4.65	0.12%	2.38	0.15%	7.35	0.78%	2.01	0.18%	5.26	0.44%	1.52	0.20%
>$75k	15.09	0.26%	4.59	0.22%	7.88	0.93%	2.99	0.28%	5.64	0.72%	1.63	0.28%
Total	19.67	0.17%	6.81	0.15%	18.77	0.73%	5.21	0.18%	13.34	0.47%	3.73	0.20%

Table J-8. Distribution of Real Household Income (millions of dollars), 2040

Household Income	Metro Amount	Metro Percent Change	East Amount	East Percent Change	West Amount	West Percent Change	North Amount	North Percent Change	South Amount	South Percent Change	Central Amount	Central Percent Change
<$10k	0.34	0.33%	0.09	0.18%	0.15	0.27%	0.24	0.66%	0.24	0.44%	0.15	0.45%
$10k-$15k	0.42	0.24%	0.16	0.20%	0.50	0.59%	0.25	0.53%	0.78	0.71%	0.23	0.43%
$15k-$25k	2.34	0.36%	1.26	0.37%	1.80	0.65%	1.60	0.59%	3.50	1.04%	1.19	0.54%
$25k-$35k	3.57	0.42%	1.95	0.41%	2.32	0.66%	2.17	0.62%	3.26	0.95%	1.36	0.53%
$35k-$75k	20.89	0.53%	9.11	0.57%	7.89	0.83%	9.62	0.84%	13.98	1.17%	4.92	0.65%
>$75k	36.24	0.62%	14.80	0.72%	7.18	0.85%	10.10	0.95%	11.74	1.50%	4.01	0.69%
Total	63.80	0.55%	27.37	0.59%	19.85	0.77%	23.98	0.82%	33.50	1.19%	11.88	0.62%

Table J-9. Distribution of Real Household Income (millions of dollars), 2045

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-0.26	-0.26%	-0.27	-0.51%	-0.20	-0.35%	-0.07	-0.20%	-0.16	-0.30%	-0.11	-0.32%
$10k-$15k	-0.35	-0.20%	-0.21	-0.25%	0.02	0.03%	-0.05	-0.11%	-0.03	-0.03%	-0.08	-0.14%
$15k-$25k	-0.25	-0.04%	-0.13	-0.04%	0.33	0.12%	0.10	0.04%	0.55	0.16%	-0.04	-0.02%
$25k-$35k	0.58	0.07%	0.14	0.03%	0.66	0.19%	0.26	0.07%	0.67	0.19%	0.09	0.03%
$35k-$75k	4.90	0.12%	2.59	0.16%	2.73	0.29%	2.35	0.21%	2.86	0.24%	0.48	0.06%
>$75k	16.33	0.28%	6.07	0.30%	3.29	0.39%	3.30	0.31%	3.54	0.45%	0.72	0.12%
Total	20.94	0.18%	8.19	0.18%	6.83	0.27%	5.88	0.20%	7.43	0.26%	1.06	0.06%

Table J-10. Distribution of Real Household Income (millions of dollars), 2050

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	2.08	2.08%	-0.66	-1.23%	-0.04	-0.08%	-0.01	-0.02%	-0.01	-0.01%	-0.13	-0.40%
$10k-$15k	2.63	1.54%	-0.28	-0.35%	1.88	2.22%	0.10	0.21%	1.17	1.06%	0.14	0.26%
$15k-$25k	20.46	3.15%	3.56	1.04%	7.78	2.81%	3.22	1.19%	8.39	2.49%	2.16	0.97%
$25k-$35k	33.15	3.87%	7.13	1.50%	11.51	3.26%	6.11	1.74%	9.44	2.75%	3.58	1.40%
$35k-$75k	202.74	5.15%	36.82	2.29%	39.10	4.13%	27.59	2.41%	41.22	3.44%	15.16	1.99%
>$75k	397.08	6.77%	58.65	2.86%	37.56	4.45%	31.60	2.97%	35.75	4.58%	12.77	2.21%
Total	658.15	5.68%	105.23	2.28%	97.78	3.82%	68.61	2.36%	95.96	3.40%	33.68	1.77%

J.2 Impacts of 1LM Scenario

Table J-11. Changes in Real Household Income (millions of dollars), by Region

Region	2025		2028		2030		2035		2040		2045		2050	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
Metro	-276.8	-2.39%	98.4	0.85%	102.9	0.89%	116.5	1.01%	149.7	1.29%	89.3	0.77%	538.5	4.65%
East	-150.0	-3.25%	74.3	1.61%	49.2	1.07%	56.4	1.22%	73.2	1.59%	44.2	0.96%	92.6	2.01%
West	-3.9	-0.15%	26.5	1.03%	28.0	1.09%	36.5	1.42%	42.7	1.66%	25.0	0.98%	90.5	3.53%
North	-79.3	-2.72%	46.7	1.60%	30.0	1.03%	34.2	1.17%	44.1	1.52%	26.5	0.91%	60.0	2.06%
South	9.9	0.35%	38.9	1.38%	32.9	1.16%	38.6	1.37%	51.8	1.84%	29.1	1.03%	110.4	3.91%
Central	-80.7	-4.23%	19.3	1.01%	20.6	1.08%	23.8	1.25%	31.9	1.67%	17.6	0.92%	32.1	1.69%
Total	-580.7	-2.20%	304.1	1.15%	263.5	1.00%	305.8	1.16%	393.4	1.49%	231.6	0.88%	924.2	3.50%

Table J-12. Changes in Employment, by Region

Region	2025		2028		2030		2035		2040		2045		2050	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
Metro	-743	-0.20%	2,490	0.66%	1,566	0.41%	1,939	0.51%	2,457	0.65%	1,450	0.38%	1,521	0.40%
East	-1,424	-0.82%	481	0.28%	738	0.43%	903	0.52%	1,143	0.66%	622	0.36%	2,555	1.47%
West	-1,688	-1.45%	730	0.63%	468	0.40%	462	0.40%	702	0.60%	404	0.35%	1,033	0.89%
North	-1,484	-1.23%	281	0.23%	460	0.38%	572	0.47%	724	0.60%	410	0.34%	1,933	1.60%
South	-3,386	-2.63%	575	0.45%	486	0.38%	575	0.45%	678	0.53%	426	0.33%	931	0.72%
Central	-453	-0.52%	623	0.72%	437	0.50%	524	0.61%	641	0.74%	393	0.45%	1,618	1.87%
total	-9,178	-0.91%	5,180	0.52%	4,155	0.41%	4,974	0.49%	6,345	0.63%	3,704	0.37%	9,591	0.95%

Table J-13. Distribution of Real Household Income (millions of dollars), 2025

Household Income	Metro Amount	Metro Percent Change	East Amount	East Percent Change	West Amount	West Percent Change	North Amount	North Percent Change	South Amount	South Percent Change	Central Amount	Central Percent Change
<$10k	-10.51	-10.49%	-7.32	-13.77%	-5.57	-9.83%	-4.41	-12.34%	-5.94	-10.91%	-4.10	-12.24%
$10k-$15k	-13.68	-7.98%	-6.87	-8.52%	-3.77	-4.46%	-4.06	-8.62%	-5.13	-4.65%	-4.33	-7.94%
$15k-$25k	-34.87	-5.37%	-18.45	-5.37%	-6.56	-2.37%	-14.24	-5.27%	-4.31	-1.28%	-12.41	-5.60%
$25k-$35k	-27.03	-3.16%	-17.89	-3.76%	-2.71	-0.77%	-14.71	-4.18%	0.50	0.15%	-10.18	-3.97%
$35k-$75k	-129.31	-3.29%	-51.08	-3.18%	-1.40	-0.15%	-32.98	-2.88%	-3.81	-0.32%	-32.46	-4.26%
>$75k	-61.41	-1.05%	-48.36	-2.36%	16.11	1.91%	-8.88	-0.84%	28.56	3.66%	-17.17	-2.97%
Total	-276.81	-2.39%	-149.97	-3.25%	-3.90	-0.15%	-79.28	-2.72%	9.87	0.35%	-80.66	-4.23%

Table J-14. Distribution of Real Household Income (millions of dollars), 2028

Household Income	Metro Amount	Metro Percent Change	East Amount	East Percent Change	West Amount	West Percent Change	North Amount	North Percent Change	South Amount	South Percent Change	Central Amount	Central Percent Change
<$10k	1.39	1.39%	0.77	1.46%	0.83	1.46%	0.78	2.19%	0.84	1.55%	0.53	1.57%
$10k-$15k	1.79	1.05%	0.82	1.02%	1.02	1.20%	0.77	1.63%	1.34	1.21%	0.60	1.10%
$15k-$25k	5.98	0.92%	3.71	1.08%	3.07	1.11%	3.80	1.41%	4.41	1.31%	2.17	0.98%
$25k-$35k	6.83	0.80%	5.00	1.05%	3.45	0.98%	4.79	1.36%	3.95	1.15%	2.31	0.90%
$35k-$75k	37.06	0.94%	23.32	1.45%	10.57	1.12%	18.83	1.65%	17.31	1.44%	8.18	1.07%
>$75k	45.38	0.77%	40.69	1.99%	7.53	0.89%	17.68	1.66%	11.05	1.41%	5.53	0.96%
Total	98.43	0.85%	74.32	1.61%	26.47	1.03%	46.65	1.60%	38.90	1.38%	19.32	1.01%

Table J-15. Distribution of Real Household Income (millions of dollars), 2030

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	1.71	1.71%	1.06	2.00%	1.01	1.78%	0.71	1.97%	0.99	1.81%	0.65	1.94%
$10k-$15k	2.22	1.30%	1.00	1.24%	1.19	1.41%	0.67	1.42%	1.36	1.23%	0.71	1.30%
$15k-$25k	6.91	1.07%	3.47	1.01%	3.46	1.25%	2.92	1.08%	3.95	1.17%	2.42	1.09%
$25k-$35k	7.19	0.84%	4.35	0.92%	3.61	1.02%	3.72	1.06%	3.39	0.99%	2.44	0.95%
$35k-$75k	39.90	1.01%	16.10	1.00%	11.13	1.18%	12.12	1.06%	15.06	1.26%	8.60	1.13%
>$75k	44.94	0.77%	23.19	1.13%	7.61	0.90%	9.85	0.93%	8.13	1.04%	5.73	0.99%
Total	102.88	0.89%	49.17	1.07%	28.00	1.09%	29.98	1.03%	32.88	1.16%	20.55	1.08%

Table J-16. Distribution of Real Household Income (millions of dollars), 2035

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	1.99	1.99%	1.25	2.35%	1.18	2.09%	0.82	2.28%	1.16	2.13%	0.76	2.27%
$10k-$15k	2.58	1.51%	1.18	1.46%	1.49	1.76%	0.77	1.64%	1.60	1.45%	0.83	1.52%
$15k-$25k	7.98	1.23%	4.04	1.18%	4.40	1.59%	3.36	1.24%	4.63	1.38%	2.80	1.26%
$25k-$35k	8.27	0.97%	5.06	1.06%	4.58	1.30%	4.29	1.22%	3.98	1.16%	2.83	1.10%
$35k-$75k	45.48	1.16%	18.49	1.15%	14.46	1.53%	13.80	1.21%	17.65	1.47%	9.96	1.31%
>$75k	50.14	0.85%	26.34	1.29%	10.36	1.23%	11.14	1.05%	9.53	1.22%	6.60	1.14%
Total	116.45	1.01%	56.36	1.22%	36.47	1.42%	34.17	1.17%	38.56	1.37%	23.77	1.25%

Table J-17. Distribution of Real Household Income (millions of dollars), 2040

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	2.65	2.65%	1.68	3.15%	1.59	2.80%	1.08	3.02%	1.55	2.85%	1.02	3.06%
$10k-$15k	3.44	2.01%	1.57	1.94%	1.85	2.18%	1.02	2.17%	2.16	1.95%	1.11	2.04%
$15k-$25k	10.49	1.62%	5.30	1.54%	5.34	1.93%	4.39	1.62%	6.25	1.86%	3.77	1.70%
$25k-$35k	10.76	1.26%	6.62	1.39%	5.51	1.56%	5.60	1.59%	5.33	1.55%	3.79	1.48%
$35k-$75k	58.99	1.50%	23.99	1.49%	16.94	1.79%	17.81	1.56%	23.68	1.98%	13.32	1.75%
>$75k	63.38	1.08%	34.05	1.66%	11.44	1.36%	14.20	1.34%	12.86	1.65%	8.87	1.53%
Total	149.71	1.29%	73.21	1.59%	42.66	1.66%	44.11	1.52%	51.83	1.84%	31.89	1.67%

Table J-18. Distribution of Real Household Income (millions of dollars), 2045

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	1.37	1.37%	0.83	1.55%	0.80	1.41%	0.58	1.61%	0.79	1.45%	0.52	1.56%
$10k-$15k	1.77	1.04%	0.80	0.99%	1.00	1.19%	0.55	1.16%	1.13	1.03%	0.58	1.06%
$15k-$25k	5.69	0.88%	2.90	0.84%	2.98	1.07%	2.47	0.92%	3.42	1.02%	2.03	0.92%
$25k-$35k	6.10	0.71%	3.71	0.78%	3.17	0.90%	3.18	0.90%	2.98	0.87%	2.08	0.81%
$35k-$75k	34.00	0.86%	14.40	0.90%	9.95	1.05%	10.70	0.94%	13.19	1.10%	7.34	0.96%
>$75k	40.34	0.69%	21.59	1.05%	7.14	0.85%	9.02	0.85%	7.55	0.97%	5.00	0.86%
Total	89.27	0.77%	44.22	0.96%	25.04	0.98%	26.49	0.91%	29.05	1.03%	17.55	0.92%

Table J-19. Distribution of Real Household Income (millions of dollars), 2050

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	2.30	2.29%	0.06	0.11%	0.45	0.80%	0.27	0.75%	0.62	1.14%	0.17	0.52%
$10k-$15k	2.91	1.70%	0.29	0.37%	2.08	2.46%	0.32	0.69%	2.15	1.95%	0.39	0.71%
$15k-$25k	18.23	2.81%	4.24	1.23%	7.83	2.82%	3.45	1.28%	10.79	3.21%	2.45	1.10%
$25k-$35k	27.55	3.22%	7.22	1.52%	10.73	3.05%	5.98	1.70%	11.00	3.20%	3.56	1.39%
$35k-$75k	169.79	4.31%	32.75	2.04%	36.15	3.82%	24.14	2.11%	47.25	3.94%	14.43	1.89%
>$75k	317.73	5.41%	48.00	2.34%	33.29	3.94%	25.88	2.43%	38.63	4.95%	11.15	1.93%
Total	538.50	4.65%	92.57	2.01%	90.54	3.53%	60.04	2.06%	110.44	3.91%	32.15	1.69%

J.3 Impacts of 1MS Scenario

Table J-20. Changes in Real Household Income (millions of dollars), by Region

Region	2025		2028		2030		2035		2040		2045		2050	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
Metro	-338.5	-2.92%	65.1	0.56%	19.5	0.17%	35.5	0.31%	46.4	0.40%	21.6	0.19%	578.2	4.99%
East	-129.7	-2.81%	42.0	0.91%	7.3	0.16%	13.1	0.28%	22.2	0.48%	9.3	0.20%	52.3	1.13%
West	-62.7	-2.45%	10.0	0.39%	3.5	0.13%	36.8	1.44%	16.2	0.63%	5.8	0.23%	99.8	3.89%
North	-124.8	-4.29%	11.3	0.39%	3.3	0.11%	8.1	0.28%	11.4	0.39%	3.9	0.13%	68.5	2.35%
South	118.0	4.18%	27.3	0.97%	7.7	0.27%	23.1	0.82%	32.1	1.14%	9.7	0.35%	122.5	4.34%
Central	-89.8	-4.71%	6.3	0.33%	0.9	0.05%	15.7	0.82%	7.3	0.38%	1.6	0.08%	27.4	1.44%
Total	-627.4	-2.38%	162.1	0.61%	42.1	0.16%	132.2	0.50%	135.6	0.51%	51.9	0.20%	948.6	3.59%

Table J-21. Changes in Employment, by Region

Region	2025		2028		2030		2035		2040		2045		2050	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
Metro	468	0.12%	895	0.24%	224	0.06%	1,914	0.50%	1,231	0.32%	392	0.10%	1,493	0.39%
East	-2,319	-1.34%	2	0.00%	56	0.03%	814	0.47%	463	0.27%	83	0.05%	3,443	1.99%
West	-444	-0.38%	403	0.35%	79	0.07%	-141	-0.12%	232	0.20%	73	0.06%	924	0.79%
North	-1,218	-1.01%	423	0.35%	102	0.08%	625	0.52%	409	0.34%	148	0.12%	1,771	1.46%
South	-5,427	-4.22%	26	0.02%	-20	-0.02%	237	0.18%	-102	-0.08%	-14	-0.01%	756	0.59%
Central	-508	-0.59%	336	0.39%	92	0.11%	151	0.17%	308	0.36%	109	0.13%	1,708	1.97%
total	-9,448	-0.94%	2,086	0.21%	534	0.05%	3,601	0.36%	2,541	0.25%	791	0.08%	10,095	1.00%

Table J-22. Distribution of Real Household Income (millions of dollars), 2025

Household Income	Metro Amount	Metro Percent Change	East Amount	East Percent Change	West Amount	West Percent Change	North Amount	North Percent Change	South Amount	South Percent Change	Central Amount	Central Percent Change
<$10k	-12.25	-12.23%	-8.58	-16.14%	-6.78	-11.98%	-5.71	-15.96%	-6.20	-11.38%	-4.77	-14.22%
$10k-$15k	-15.96	-9.31%	-8.04	-9.97%	-5.99	-7.08%	-5.34	-11.34%	-3.34	-3.02%	-5.05	-9.26%
$15k-$25k	-41.04	-6.33%	-20.80	-6.05%	-13.57	-4.89%	-19.61	-7.25%	6.83	2.03%	-14.28	-6.44%
$25k-$35k	-31.83	-3.72%	-19.20	-4.04%	-9.57	-2.71%	-20.09	-5.71%	13.45	3.92%	-11.47	-4.47%
$35k-$75k	-153.85	-3.91%	-47.34	-2.95%	-23.51	-2.48%	-51.67	-4.52%	39.41	3.29%	-36.07	-4.74%
>$75k	-83.58	-1.42%	-25.69	-1.25%	-3.31	-0.39%	-22.34	-2.10%	67.89	8.69%	-18.16	-3.14%
Total	-338.51	-2.92%	-129.66	-2.81%	-62.72	-2.45%	-124.75	-4.29%	118.04	4.18%	-89.80	-4.71%

Table J-23. Distribution of Real Household Income (millions of dollars), 2028

Household Income	Metro Amount	Metro Percent Change	East Amount	East Percent Change	West Amount	West Percent Change	North Amount	North Percent Change	South Amount	South Percent Change	Central Amount	Central Percent Change
<$10k	0.19	0.19%	-0.08	-0.14%	0.04	0.07%	0.04	0.12%	0.11	0.21%	0.03	0.09%
$10k-$15k	0.22	0.13%	0.03	0.04%	0.19	0.23%	0.06	0.12%	0.55	0.50%	0.08	0.14%
$15k-$25k	1.93	0.30%	1.22	0.36%	0.77	0.28%	0.64	0.24%	2.74	0.82%	0.51	0.23%
$25k-$35k	3.21	0.38%	2.04	0.43%	1.27	0.36%	1.10	0.31%	2.61	0.76%	0.71	0.28%
$35k-$75k	20.52	0.52%	12.93	0.80%	4.08	0.43%	4.50	0.39%	11.37	0.95%	2.79	0.37%
>$75k	39.06	0.67%	25.88	1.26%	3.65	0.43%	4.95	0.47%	9.93	1.27%	2.20	0.38%
Total	65.14	0.56%	42.01	0.91%	10.00	0.39%	11.30	0.39%	27.31	0.97%	6.33	0.33%

Table J-24. Distribution of Real Household Income (millions of dollars), 2030

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-0.16	-0.16%	-0.19	-0.36%	-0.14	-0.24%	-0.06	-0.18%	-0.11	-0.19%	-0.08	-0.22%
$10k-$15k	-0.23	-0.13%	-0.14	-0.18%	-0.02	-0.02%	-0.05	-0.11%	0.03	0.03%	-0.05	-0.10%
$15k-$25k	-0.03	0.00%	-0.05	-0.01%	0.10	0.04%	0.01	0.00%	0.65	0.19%	-0.02	-0.01%
$25k-$35k	0.61	0.07%	0.17	0.04%	0.35	0.10%	0.14	0.04%	0.69	0.20%	0.08	0.03%
$35k-$75k	4.95	0.13%	2.29	0.14%	1.41	0.15%	1.29	0.11%	3.01	0.25%	0.42	0.05%
>$75k	14.38	0.24%	5.21	0.25%	1.76	0.21%	1.94	0.18%	3.41	0.44%	0.56	0.10%
Total	19.51	0.17%	7.29	0.16%	3.45	0.13%	3.26	0.11%	7.68	0.27%	0.91	0.05%

Table J-25. Distribution of Real Household Income (millions of dollars), 2035

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-0.14	-0.14%	-0.19	-0.35%	-0.04	-0.08%	-0.07	-0.19%	-0.04	-0.07%	0.10	0.30%
$10k-$15k	-0.20	-0.12%	-0.10	-0.12%	0.82	0.97%	-0.04	-0.08%	0.35	0.32%	0.25	0.46%
$15k-$25k	0.45	0.07%	0.39	0.11%	3.21	1.16%	0.29	0.11%	2.22	0.66%	1.66	0.75%
$25k-$35k	1.78	0.21%	0.93	0.19%	3.91	1.11%	0.65	0.19%	2.23	0.65%	1.79	0.70%
$35k-$75k	9.94	0.25%	4.68	0.29%	14.36	1.52%	3.08	0.27%	9.35	0.78%	6.14	0.81%
>$75k	23.68	0.40%	7.34	0.36%	14.59	1.73%	4.21	0.40%	8.94	1.15%	5.71	0.99%
Total	35.51	0.31%	13.05	0.28%	36.84	1.44%	8.12	0.28%	23.05	0.82%	15.65	0.82%

Table J-26. Distribution of Real Household Income (millions of dollars), 2040

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	0.25	0.25%	0.07	0.13%	0.12	0.21%	0.10	0.28%	0.21	0.38%	0.09	0.28%
$10k-$15k	0.31	0.18%	0.12	0.15%	0.41	0.49%	0.11	0.23%	0.76	0.69%	0.14	0.26%
$15k-$25k	1.72	0.27%	0.98	0.28%	1.47	0.53%	0.77	0.29%	3.40	1.01%	0.71	0.32%
$25k-$35k	2.63	0.31%	1.52	0.32%	1.87	0.53%	1.16	0.33%	3.08	0.90%	0.85	0.33%
$35k-$75k	15.27	0.39%	7.29	0.45%	6.44	0.68%	4.52	0.40%	13.25	1.11%	3.10	0.41%
>$75k	26.24	0.45%	12.20	0.60%	5.90	0.70%	4.74	0.45%	11.39	1.46%	2.41	0.42%
Total	46.42	0.40%	22.18	0.48%	16.21	0.63%	11.40	0.39%	32.09	1.14%	7.31	0.38%

Table J-27. Distribution of Real Household Income (millions of dollars), 2045

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-0.26	-0.26%	-0.27	-0.51%	-0.20	-0.35%	-0.10	-0.27%	-0.15	-0.28%	-0.10	-0.30%
$10k-$15k	-0.35	-0.20%	-0.20	-0.25%	0.00	0.00%	-0.08	-0.17%	0.03	0.02%	-0.07	-0.12%
$15k-$25k	-0.23	-0.04%	-0.11	-0.03%	0.23	0.08%	-0.03	-0.01%	0.81	0.24%	0.02	0.01%
$25k-$35k	0.61	0.07%	0.18	0.04%	0.57	0.16%	0.12	0.04%	0.88	0.26%	0.15	0.06%
$35k-$75k	5.11	0.13%	2.90	0.18%	2.33	0.25%	1.53	0.13%	3.78	0.32%	0.68	0.09%
>$75k	16.73	0.29%	6.78	0.33%	2.87	0.34%	2.44	0.23%	4.41	0.57%	0.91	0.16%
Total	21.62	0.19%	9.27	0.20%	5.79	0.23%	3.88	0.13%	9.75	0.35%	1.60	0.08%

Table J-28. Distribution of Real Household Income (millions of dollars), 2050

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	1.64	1.64%	-0.56	-1.05%	-0.02	-0.04%	0.03	0.09%	0.18	0.33%	-0.19	-0.57%
$10k-$15k	2.07	1.21%	-0.29	-0.36%	1.97	2.33%	0.14	0.29%	1.99	1.80%	0.04	0.07%
$15k-$25k	17.43	2.69%	2.36	0.69%	8.14	2.94%	3.28	1.21%	11.65	3.46%	1.61	0.72%
$25k-$35k	28.70	3.35%	5.18	1.09%	11.65	3.30%	5.94	1.69%	12.27	3.57%	2.94	1.14%
$35k-$75k	177.38	4.51%	21.44	1.33%	39.65	4.19%	27.46	2.40%	51.51	4.30%	12.55	1.65%
>$75k	350.99	5.98%	24.15	1.18%	38.37	4.54%	31.60	2.97%	44.90	5.75%	10.48	1.81%
Total	578.20	4.99%	52.28	1.13%	99.77	3.89%	68.46	2.35%	122.50	4.34%	27.42	1.44%

J.4 Impacts of 2LS Scenario

Table J-29. Changes in Real Household Income (millions of dollars), by Region

Region	2025		2028		2030		2035		2040		2045		2050	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
Metro	-329.2	-2.84%	45.3	0.39%	16.2	0.14%	7.4	0.06%	45.3	0.39%	11.6	0.10%	668.1	5.77%
East	-174.6	-3.79%	54.7	1.19%	8.9	0.19%	1.0	0.02%	18.4	0.40%	3.9	0.08%	104.7	2.27%
West	-22.5	-0.88%	12.9	0.50%	5.6	0.22%	12.1	0.47%	18.6	0.72%	4.3	0.17%	93.4	3.64%
North	-100.9	-3.46%	24.5	0.84%	4.5	0.16%	1.8	0.06%	16.0	0.55%	3.1	0.11%	71.2	2.44%
South	2.2	0.08%	22.0	0.78%	6.0	0.21%	9.5	0.34%	27.2	0.96%	4.4	0.15%	100.7	3.57%
Central	-93.5	-4.90%	6.9	0.36%	1.6	0.08%	1.7	0.09%	9.0	0.47%	-0.8	-0.04%	32.7	1.71%
Total	-718.5	-2.72%	166.3	0.63%	42.8	0.16%	33.5	0.13%	134.4	0.51%	26.4	0.10%	1,070.7	4.06%

Table J-30. Changes in Employment, by Region

Region	2025		2028		2030		2035		2040		2045		2050	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
Metro	-1,186	-0.31%	1,678	0.44%	391	0.10%	681	0.18%	1,381	0.36%	248	0.07%	1,033	0.27%
East	-2,034	-1.17%	-113	-0.07%	47	0.03%	235	0.14%	567	0.33%	25	0.01%	2,508	1.45%
West	-1,654	-1.42%	429	0.37%	46	0.04%	-102	-0.09%	196	0.17%	-3	0.00%	1,218	1.05%
North	-2,229	-1.84%	184	0.15%	94	0.08%	189	0.16%	309	0.26%	44	0.04%	1,915	1.58%
South	-4,315	-3.36%	277	0.22%	50	0.04%	-33	-0.03%	42	0.03%	-1	0.00%	1,382	1.07%
Central	-736	-0.85%	391	0.45%	85	0.10%	77	0.09%	264	0.30%	80	0.09%	1,715	1.98%
total	-12,154	-1.21%	2,846	0.28%	713	0.07%	1,048	0.10%	2,759	0.27%	392	0.04%	9,771	0.97%

Table J-31. Distribution of Real Household Income (millions of dollars), 2025

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-12.23	-12.21%	-8.58	-16.13%	-6.52	-11.51%	-5.43	-15.18%	-7.29	-13.39%	-4.81	-14.34%
$10k-$15k	-15.92	-9.29%	-8.15	-10.11%	-4.87	-5.76%	-5.03	-10.69%	-6.62	-6.00%	-5.12	-9.39%
$15k-$25k	-40.85	-6.30%	-22.09	-6.43%	-9.41	-3.39%	-17.98	-6.65%	-6.61	-1.96%	-14.65	-6.61%
$25k-$35k	-31.90	-3.72%	-21.24	-4.47%	-5.15	-1.46%	-18.34	-5.21%	-0.30	-0.09%	-11.92	-4.65%
$35k-$75k	-151.41	-3.85%	-60.40	-3.76%	-8.34	-0.88%	-41.97	-3.67%	-8.14	-0.68%	-37.59	-4.94%
>$75k	-76.91	-1.31%	-54.14	-2.64%	11.78	1.39%	-12.12	-1.14%	31.19	3.99%	-19.37	-3.35%
Total	-329.23	-2.84%	-174.61	-3.79%	-22.51	-0.88%	-100.87	-3.46%	2.23	0.08%	-93.46	-4.90%

Table J-32. Distribution of Real Household Income (millions of dollars), 2028

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	0.03	0.03%	-0.16	-0.31%	-0.01	-0.01%	0.17	0.48%	0.05	0.09%	0.01	0.04%
$10k-$15k	0.02	0.01%	-0.01	-0.01%	0.24	0.28%	0.19	0.41%	0.38	0.35%	0.07	0.13%
$15k-$25k	1.12	0.17%	1.43	0.42%	0.99	0.36%	1.47	0.54%	2.12	0.63%	0.58	0.26%
$25k-$35k	2.41	0.28%	2.42	0.51%	1.54	0.44%	2.00	0.57%	2.14	0.62%	0.79	0.31%
$35k-$75k	13.98	0.36%	16.48	1.03%	5.20	0.55%	9.83	0.86%	9.19	0.77%	3.00	0.39%
>$75k	27.73	0.47%	34.53	1.69%	4.96	0.59%	10.81	1.02%	8.12	1.04%	2.48	0.43%
Total	45.30	0.39%	54.69	1.19%	12.92	0.50%	24.47	0.84%	22.00	0.78%	6.94	0.36%

Table J-33. Distribution of Real Household Income (millions of dollars), 2030

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-0.25	-0.25%	-0.25	-0.47%	-0.18	-0.32%	-0.08	-0.21%	-0.15	-0.28%	-0.09	-0.26%
$10k-$15k	-0.33	-0.19%	-0.19	-0.23%	0.01	0.01%	-0.06	-0.12%	-0.04	-0.04%	-0.06	-0.10%
$15k-$25k	-0.32	-0.05%	-0.10	-0.03%	0.24	0.09%	0.04	0.01%	0.43	0.13%	0.04	0.02%
$25k-$35k	0.40	0.05%	0.15	0.03%	0.54	0.15%	0.17	0.05%	0.54	0.16%	0.15	0.06%
$35k-$75k	3.55	0.09%	2.73	0.17%	2.24	0.24%	1.79	0.16%	2.30	0.19%	0.66	0.09%
>$75k	13.12	0.22%	6.58	0.32%	2.75	0.33%	2.64	0.25%	2.96	0.38%	0.89	0.15%
Total	16.16	0.14%	8.91	0.19%	5.59	0.22%	4.51	0.16%	6.03	0.21%	1.61	0.08%

Table J-34. Distribution of Real Household Income (millions of dollars), 2035

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-0.53	-0.53%	-0.43	-0.81%	-0.34	-0.59%	-0.19	-0.54%	-0.29	-0.53%	-0.16	-0.49%
$10k-$15k	-0.70	-0.41%	-0.35	-0.43%	0.08	0.09%	-0.16	-0.35%	-0.08	-0.07%	-0.11	-0.21%
$15k-$25k	-1.25	-0.19%	-0.57	-0.16%	0.67	0.24%	-0.33	-0.12%	0.70	0.21%	0.01	0.00%
$25k-$35k	-0.29	-0.03%	-0.35	-0.07%	1.10	0.31%	-0.23	-0.06%	0.83	0.24%	0.14	0.06%
$35k-$75k	-0.50	-0.01%	0.43	0.03%	4.72	0.50%	0.63	0.05%	3.43	0.29%	0.63	0.08%
>$75k	10.68	0.18%	2.28	0.11%	5.82	0.69%	2.06	0.19%	4.91	0.63%	1.20	0.21%
Total	7.43	0.06%	1.01	0.02%	12.06	0.47%	1.77	0.06%	9.50	0.34%	1.70	0.09%

Table J-35. Distribution of Real Household Income (millions of dollars), 2040

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	0.03	0.03%	-0.09	-0.17%	-0.02	-0.03%	0.08	0.22%	0.06	0.11%	0.05	0.14%
$10k-$15k	0.03	0.02%	-0.02	-0.02%	0.39	0.46%	0.10	0.21%	0.53	0.48%	0.13	0.23%
$15k-$25k	1.12	0.17%	0.64	0.19%	1.53	0.55%	0.91	0.34%	2.74	0.82%	0.85	0.38%
$25k-$35k	2.30	0.27%	1.19	0.25%	2.05	0.58%	1.32	0.38%	2.61	0.76%	1.01	0.39%
$35k-$75k	13.78	0.35%	6.18	0.38%	7.35	0.78%	6.38	0.56%	11.12	0.93%	3.69	0.48%
>$75k	28.06	0.48%	10.46	0.51%	7.27	0.86%	7.21	0.68%	10.12	1.30%	3.27	0.57%
Total	45.32	0.39%	18.36	0.40%	18.57	0.72%	15.99	0.55%	27.18	0.96%	8.99	0.47%

Table J-36. Distribution of Real Household Income (millions of dollars), 2045

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-0.43	-0.43%	-0.38	-0.72%	-0.30	-0.53%	-0.14	-0.40%	-0.26	-0.49%	-0.17	-0.52%
$10k-$15k	-0.58	-0.34%	-0.31	-0.38%	-0.09	-0.11%	-0.12	-0.26%	-0.17	-0.15%	-0.15	-0.27%
$15k-$25k	-0.93	-0.14%	-0.47	-0.14%	0.00	0.00%	-0.18	-0.07%	0.17	0.05%	-0.27	-0.12%
$25k-$35k	-0.11	-0.01%	-0.27	-0.06%	0.34	0.10%	-0.09	-0.03%	0.35	0.10%	-0.14	-0.05%
$35k-$75k	1.18	0.03%	1.17	0.07%	1.74	0.18%	1.23	0.11%	1.45	0.12%	-0.32	-0.04%
>$75k	12.44	0.21%	4.18	0.20%	2.65	0.31%	2.43	0.23%	2.82	0.36%	0.20	0.04%
Total	11.57	0.10%	3.91	0.08%	4.33	0.17%	3.12	0.11%	4.35	0.15%	-0.85	-0.04%

Table J-37. Distribution of Real Household Income (millions of dollars), 2050

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	2.05	2.04%	-0.72	-1.36%	-0.13	-0.24%	-0.01	-0.04%	-0.03	-0.05%	-0.18	-0.54%
$10k-$15k	2.59	1.51%	-0.34	-0.42%	1.71	2.03%	0.10	0.21%	1.24	1.13%	0.09	0.17%
$15k-$25k	20.61	3.18%	3.45	1.00%	7.24	2.61%	3.31	1.23%	8.86	2.63%	2.00	0.90%
$25k-$35k	33.61	3.92%	7.06	1.48%	11.00	3.12%	6.25	1.78%	9.92	2.89%	3.46	1.35%
$35k-$75k	205.40	5.22%	36.71	2.28%	37.44	3.95%	28.61	2.50%	43.09	3.60%	14.80	1.94%
>$75k	403.83	6.88%	58.55	2.86%	36.11	4.28%	32.90	3.10%	37.63	4.82%	12.51	2.16%
Total	668.09	5.77%	104.71	2.27%	93.37	3.64%	71.15	2.44%	100.71	3.57%	32.68	1.71%

J.5 Impacts of 3LS Scenario

Table J-38. Changes in Real Household Income (millions of dollars), by Region

Region	2025		2028		2030		2035		2040		2045		2050	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
Metro	-364.3	-3.15%	62.6	0.54%	33.7	0.29%	-41.4	-0.36%	-40.6	-0.35%	-30.7	-0.26%	738.9	6.38%
East	-199.7	-4.33%	72.2	1.57%	16.5	0.36%	-23.2	-0.50%	-22.6	-0.49%	-17.5	-0.38%	120.0	2.60%
West	-25.7	-1.00%	17.4	0.68%	9.6	0.37%	-5.6	-0.22%	-10.2	-0.40%	-7.4	-0.29%	122.6	4.78%
North	-121.5	-4.17%	30.2	1.04%	9.6	0.33%	-13.0	-0.45%	-12.7	-0.44%	-9.4	-0.32%	84.4	2.90%
South	-49.4	-1.75%	24.6	0.87%	9.7	0.34%	-13.6	-0.48%	-13.9	-0.49%	-10.6	-0.37%	144.7	5.12%
Central	-104.0	-5.46%	9.4	0.49%	3.1	0.16%	-13.9	-0.73%	-13.2	-0.69%	-10.6	-0.56%	40.9	2.14%
Total	-864.7	-3.28%	216.4	0.82%	82.1	0.31%	-110.7	-0.42%	-113.1	-0.43%	-86.2	-0.33%	1,251.5	4.74%

Table J-39. Changes in Employment, by Region

Region	2025		2028		2030		2035		2040		2045		2050	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
Metro	-2,406	-0.63%	2,023	0.53%	598	0.16%	-519	-0.14%	-661	-0.17%	-488	-0.13%	2,345	0.62%
East	-2,700	-1.56%	-182	-0.11%	98	0.06%	-406	-0.23%	-433	-0.25%	-336	-0.19%	3,418	1.97%
West	-2,040	-1.75%	518	0.44%	105	0.09%	-374	-0.32%	-280	-0.24%	-226	-0.19%	1,396	1.20%
North	-3,019	-2.49%	263	0.22%	134	0.11%	-198	-0.16%	-233	-0.19%	-183	-0.15%	2,447	2.02%
South	-4,638	-3.61%	440	0.34%	135	0.10%	-258	-0.20%	-272	-0.21%	-210	-0.16%	1,354	1.05%
Central	-1,093	-1.26%	479	0.55%	161	0.19%	-125	-0.14%	-149	-0.17%	-103	-0.12%	2,167	2.50%
total	-15,894	-1.58%	3,540	0.35%	1,232	0.12%	-1,881	-0.19%	-2,028	-0.20%	-1,545	-0.15%	13,126	1.31%

Table J-40. Distribution of Real Household Income (millions of dollars), 2025

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-13.37	-13.35%	-9.43	-17.74%	-7.06	-12.46%	-6.21	-17.35%	-8.67	-15.93%	-5.30	-15.81%
$10k-$15k	-17.42	-10.17%	-9.06	-11.24%	-5.33	-6.30%	-5.79	-12.30%	-9.02	-8.17%	-5.69	-10.43%
$15k-$25k	-44.89	-6.92%	-24.95	-7.26%	-10.26	-3.70%	-21.08	-7.80%	-13.64	-4.05%	-16.37	-7.38%
$25k-$35k	-35.42	-4.14%	-24.10	-5.07%	-5.72	-1.62%	-21.46	-6.09%	-6.25	-1.82%	-13.35	-5.20%
$35k-$75k	-166.32	-4.23%	-69.50	-4.32%	-9.53	-1.01%	-50.46	-4.41%	-30.14	-2.52%	-41.86	-5.50%
>$75k	-86.89	-1.48%	-62.69	-3.06%	12.24	1.45%	-16.52	-1.55%	18.29	2.34%	-21.45	-3.71%
Total	-364.32	-3.15%	-199.74	-4.33%	-25.66	-1.00%	-121.52	-4.17%	-49.43	-1.75%	-104.02	-5.46%

Table J-41. Distribution of Real Household Income (millions of dollars), 2028

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	0.05	0.05%	-0.21	-0.39%	-0.01	-0.02%	0.20	0.56%	0.04	0.08%	0.02	0.07%
$10k-$15k	0.04	0.02%	0.00	0.00%	0.32	0.38%	0.23	0.49%	0.40	0.36%	0.10	0.19%
$15k-$25k	1.55	0.24%	1.91	0.56%	1.34	0.48%	1.80	0.66%	2.31	0.69%	0.79	0.36%
$25k-$35k	3.25	0.38%	3.24	0.68%	2.06	0.58%	2.49	0.71%	2.42	0.70%	1.06	0.41%
$35k-$75k	19.29	0.49%	21.76	1.35%	7.02	0.74%	12.11	1.06%	10.39	0.87%	4.04	0.53%
>$75k	38.38	0.65%	45.46	2.22%	6.72	0.80%	13.34	1.26%	9.08	1.16%	3.38	0.58%
Total	62.56	0.54%	72.17	1.57%	17.45	0.68%	30.17	1.04%	24.64	0.87%	9.40	0.49%

Table J-42. Distribution of Real Household Income (millions of dollars), 2030

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-0.29	-0.29%	-0.34	-0.65%	-0.24	-0.42%	-0.07	-0.20%	-0.20	-0.36%	-0.11	-0.34%
$10k-$15k	-0.40	-0.23%	-0.25	-0.31%	0.05	0.06%	-0.05	-0.10%	-0.04	-0.03%	-0.06	-0.12%
$15k-$25k	-0.07	-0.01%	0.01	0.00%	0.49	0.18%	0.27	0.10%	0.70	0.21%	0.14	0.06%
$25k-$35k	1.11	0.13%	0.46	0.10%	0.97	0.27%	0.53	0.15%	0.89	0.26%	0.31	0.12%
$35k-$75k	8.54	0.22%	5.12	0.32%	3.82	0.40%	3.83	0.34%	3.80	0.32%	1.31	0.17%
>$75k	24.83	0.42%	11.50	0.56%	4.45	0.53%	5.07	0.48%	4.50	0.58%	1.53	0.26%
Total	33.72	0.29%	16.50	0.36%	9.55	0.37%	9.58	0.33%	9.65	0.34%	3.11	0.16%

Table J-43. Distribution of Real Household Income (millions of dollars), 2035

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-1.85	-1.84%	-1.35	-2.53%	-1.15	-2.03%	-0.70	-1.97%	-1.09	-2.00%	-0.71	-2.12%
$10k-$15k	-2.42	-1.41%	-1.19	-1.48%	-0.80	-0.95%	-0.64	-1.36%	-1.19	-1.08%	-0.71	-1.30%
$15k-$25k	-5.95	-0.92%	-3.03	-0.88%	-1.78	-0.64%	-2.18	-0.81%	-2.30	-0.68%	-1.98	-0.89%
$25k-$35k	-4.59	-0.54%	-3.15	-0.66%	-1.21	-0.34%	-2.46	-0.70%	-1.57	-0.46%	-1.73	-0.67%
$35k-$75k	-21.96	-0.56%	-7.83	-0.49%	-2.21	-0.23%	-5.33	-0.47%	-7.06	-0.59%	-5.73	-0.75%
>$75k	-4.68	-0.08%	-6.64	-0.32%	1.58	0.19%	-1.72	-0.16%	-0.40	-0.05%	-3.03	-0.52%
Total	-41.44	-0.36%	-23.19	-0.50%	-5.56	-0.22%	-13.03	-0.45%	-13.61	-0.48%	-13.88	-0.73%

Table J-44. Distribution of Real Household Income (millions of dollars), 2040

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-1.63	-1.63%	-1.18	-2.23%	-1.02	-1.81%	-0.62	-1.74%	-0.97	-1.78%	-0.63	-1.89%
$10k-$15k	-2.14	-1.25%	-1.06	-1.31%	-0.84	-0.99%	-0.57	-1.21%	-1.08	-0.98%	-0.64	-1.17%
$15k-$25k	-5.36	-0.83%	-2.76	-0.80%	-2.05	-0.74%	-1.99	-0.73%	-2.20	-0.65%	-1.83	-0.83%
$25k-$35k	-4.28	-0.50%	-2.93	-0.62%	-1.63	-0.46%	-2.28	-0.65%	-1.57	-0.46%	-1.63	-0.64%
$35k-$75k	-20.64	-0.52%	-7.62	-0.47%	-4.03	-0.43%	-5.17	-0.45%	-7.02	-0.59%	-5.44	-0.71%
>$75k	-6.50	-0.11%	-7.05	-0.34%	-0.67	-0.08%	-2.06	-0.19%	-1.02	-0.13%	-3.00	-0.52%
Total	-40.55	-0.35%	-22.61	-0.49%	-10.24	-0.40%	-12.69	-0.44%	-13.85	-0.49%	-13.18	-0.69%

Table J-45. Distribution of Real Household Income (millions of dollars), 2045

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-1.34	-1.34%	-0.98	-1.85%	-0.85	-1.49%	-0.51	-1.42%	-0.80	-1.46%	-0.52	-1.56%
$10k-$15k	-1.76	-1.03%	-0.87	-1.08%	-0.67	-0.79%	-0.46	-0.98%	-0.88	-0.79%	-0.53	-0.96%
$15k-$25k	-4.35	-0.67%	-2.23	-0.65%	-1.61	-0.58%	-1.57	-0.58%	-1.73	-0.51%	-1.49	-0.67%
$25k-$35k	-3.40	-0.40%	-2.35	-0.49%	-1.23	-0.35%	-1.80	-0.51%	-1.22	-0.35%	-1.32	-0.51%
$35k-$75k	-16.19	-0.41%	-5.90	-0.37%	-2.91	-0.31%	-3.85	-0.34%	-5.44	-0.45%	-4.39	-0.58%
>$75k	-3.64	-0.06%	-5.12	-0.25%	-0.14	-0.02%	-1.25	-0.12%	-0.52	-0.07%	-2.40	-0.41%
Total	-30.67	-0.26%	-17.45	-0.38%	-7.40	-0.29%	-9.45	-0.32%	-10.58	-0.37%	-10.65	-0.56%

Table J-46. Distribution of Real Household Income (millions of dollars), 2050

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	3.00	2.99%	-0.17	-0.32%	0.50	0.89%	0.29	0.82%	0.67	1.22%	0.10	0.30%
$10k-$15k	3.81	2.23%	0.18	0.22%	2.73	3.22%	0.39	0.82%	2.67	2.41%	0.39	0.71%
$15k-$25k	24.80	3.82%	5.16	1.50%	10.56	3.81%	4.64	1.72%	13.97	4.15%	2.94	1.33%
$25k-$35k	38.42	4.48%	9.18	1.93%	14.63	4.15%	8.05	2.29%	14.57	4.25%	4.49	1.75%
$35k-$75k	231.34	5.88%	42.59	2.65%	48.81	5.15%	33.90	2.97%	61.80	5.16%	18.42	2.42%
>$75k	437.54	7.45%	63.10	3.08%	45.39	5.38%	37.10	3.49%	51.01	6.53%	14.53	2.51%
Total	738.91	6.38%	120.04	2.60%	122.62	4.78%	84.38	2.90%	144.68	5.12%	40.86	2.14%

J.6 Impacts of 3MM Scenario

Table J-47. Changes in Real Household Income (millions of dollars), by Region

Region	2025		2028		2030		2035		2040		2045		2050	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
Metro	-314.7	-2.72%	120.5	1.04%	76.2	0.66%	-18.8	-0.16%	-66.3	-0.57%	-89.3	-0.77%	364.8	3.15%
East	-127.0	-2.76%	73.4	1.59%	37.6	0.82%	-10.5	-0.23%	-34.2	-0.74%	-46.4	-1.01%	23.2	0.50%
West	-60.6	-2.36%	24.0	0.94%	19.0	0.74%	-4.3	-0.17%	-18.1	-0.71%	-24.0	-0.94%	49.2	1.92%
North	-116.7	-4.01%	24.9	0.85%	19.1	0.66%	-8.4	-0.29%	-21.4	-0.73%	-28.3	-0.97%	45.4	1.56%
South	63.5	2.25%	30.1	1.06%	24.0	0.85%	-5.8	-0.20%	-20.1	-0.71%	-27.6	-0.98%	70.7	2.50%
Central	-85.1	-4.46%	17.0	0.89%	13.1	0.69%	-7.8	-0.41%	-17.8	-0.93%	-23.0	-1.21%	11.5	0.60%
Total	-640.6	-2.43%	289.9	1.10%	189.1	0.72%	-55.5	-0.21%	-177.8	-0.67%	-238.6	-0.90%	564.9	2.14%

Table J-48. Changes in Employment, by Region

Region	2025		2028		2030		2035		2040		2045		2050	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
Metro	-819	-0.22%	1,401	0.37%	1,135	0.30%	-296	-0.08%	-1,061	-0.28%	-1,466	-0.39%	308	0.08%
East	-2,535	-1.46%	124	0.07%	399	0.23%	-279	-0.16%	-632	-0.36%	-807	-0.47%	1,956	1.13%
West	-756	-0.65%	566	0.49%	340	0.29%	-169	-0.14%	-370	-0.32%	-500	-0.43%	648	0.56%
North	-1,302	-1.08%	619	0.51%	387	0.32%	-57	-0.05%	-317	-0.26%	-437	-0.36%	857	0.71%
South	-4,726	-3.68%	553	0.43%	309	0.24%	-180	-0.14%	-446	-0.35%	-574	-0.45%	335	0.26%
Central	-696	-0.80%	482	0.56%	310	0.36%	-68	-0.08%	-269	-0.31%	-366	-0.42%	1,003	1.16%
total	-10,834	-1.08%	3,744	0.37%	2,881	0.29%	-1,050	-0.10%	-3,096	-0.31%	-4,151	-0.41%	5,107	0.51%

Table J-49. Distribution of Real Household Income (millions of dollars), 2025

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-11.59	-11.57%	-8.12	-15.28%	-6.49	-11.45%	-5.29	-14.78%	-6.21	-11.42%	-4.49	-13.39%
$10k-$15k	-15.09	-8.81%	-7.60	-9.42%	-5.69	-6.73%	-4.93	-10.48%	-4.35	-3.94%	-4.74	-8.69%
$15k-$25k	-38.72	-5.97%	-19.75	-5.75%	-12.98	-4.68%	-18.12	-6.70%	1.13	0.34%	-13.39	-6.04%
$25k-$35k	-30.21	-3.53%	-18.51	-3.89%	-9.29	-2.64%	-18.76	-5.33%	6.87	2.00%	-10.87	-4.23%
$35k-$75k	-144.56	-3.67%	-46.07	-2.87%	-22.81	-2.41%	-48.19	-4.22%	17.43	1.45%	-34.30	-4.50%
>$75k	-74.54	-1.27%	-26.96	-1.32%	-3.35	-0.40%	-21.38	-2.01%	48.67	6.23%	-17.30	-2.99%
Total	-314.71	-2.72%	-127.02	-2.76%	-60.60	-2.36%	-116.67	-4.01%	63.53	2.25%	-85.09	-4.46%

Table J-50. Distribution of Real Household Income (millions of dollars), 2028

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	0.97	0.97%	0.37	0.69%	0.47	0.83%	0.35	0.98%	0.50	0.91%	0.33	0.99%
$10k-$15k	1.24	0.72%	0.47	0.58%	0.75	0.89%	0.35	0.74%	0.84	0.76%	0.42	0.77%
$15k-$25k	5.27	0.81%	2.97	0.87%	2.42	0.87%	1.94	0.72%	3.15	0.94%	1.74	0.79%
$25k-$35k	6.79	0.79%	4.31	0.91%	3.02	0.86%	2.77	0.79%	3.03	0.88%	1.95	0.76%
$35k-$75k	41.18	1.05%	22.83	1.42%	9.65	1.02%	10.01	0.88%	13.40	1.12%	7.22	0.95%
>$75k	65.06	1.11%	42.47	2.07%	7.66	0.91%	9.46	0.89%	9.14	1.17%	5.36	0.93%
Total	120.51	1.04%	73.42	1.59%	23.98	0.94%	24.88	0.85%	30.06	1.06%	17.03	0.89%

Table J-51. Distribution of Real Household Income (millions of dollars), 2030

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	0.72	0.72%	0.34	0.63%	0.37	0.66%	0.29	0.82%	0.40	0.73%	0.28	0.82%
$10k-$15k	0.92	0.54%	0.37	0.46%	0.61	0.73%	0.29	0.62%	0.71	0.64%	0.34	0.63%
$15k-$25k	3.62	0.56%	1.86	0.54%	1.97	0.71%	1.53	0.57%	2.59	0.77%	1.40	0.63%
$25k-$35k	4.51	0.53%	2.60	0.55%	2.33	0.66%	2.09	0.59%	2.39	0.70%	1.51	0.59%
$35k-$75k	26.60	0.68%	12.06	0.75%	7.60	0.80%	7.69	0.67%	10.53	0.88%	5.48	0.72%
>$75k	39.88	0.68%	20.35	0.99%	6.14	0.73%	7.22	0.68%	7.35	0.94%	4.12	0.71%
Total	76.25	0.66%	37.58	0.82%	19.03	0.74%	19.12	0.66%	23.98	0.85%	13.13	0.69%

Table J-52. Distribution of Real Household Income (millions of dollars), 2035

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-1.17	-1.16%	-0.88	-1.66%	-0.74	-1.32%	-0.46	-1.29%	-0.69	-1.27%	-0.45	-1.34%
$10k-$15k	-1.53	-0.89%	-0.77	-0.95%	-0.54	-0.64%	-0.42	-0.89%	-0.71	-0.64%	-0.44	-0.80%
$15k-$25k	-3.60	-0.56%	-1.83	-0.53%	-1.23	-0.44%	-1.41	-0.52%	-1.17	-0.35%	-1.16	-0.52%
$25k-$35k	-2.59	-0.30%	-1.84	-0.39%	-0.83	-0.24%	-1.56	-0.44%	-0.74	-0.21%	-0.99	-0.38%
$35k-$75k	-11.72	-0.30%	-3.69	-0.23%	-1.66	-0.18%	-3.46	-0.30%	-3.33	-0.28%	-3.21	-0.42%
>$75k	1.83	0.03%	-1.51	-0.07%	0.75	0.09%	-1.12	-0.11%	0.86	0.11%	-1.52	-0.26%
Total	-18.79	-0.16%	-10.52	-0.23%	-4.27	-0.17%	-8.44	-0.29%	-5.77	-0.20%	-7.76	-0.41%

Table J-53. Distribution of Real Household Income (millions of dollars), 2040

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-2.03	-2.02%	-1.42	-2.67%	-1.25	-2.20%	-0.80	-2.24%	-1.19	-2.18%	-0.78	-2.31%
$10k-$15k	-2.65	-1.55%	-1.29	-1.60%	-1.14	-1.35%	-0.74	-1.58%	-1.36	-1.23%	-0.80	-1.46%
$15k-$25k	-7.00	-1.08%	-3.59	-1.04%	-2.97	-1.07%	-2.77	-1.03%	-2.96	-0.88%	-2.37	-1.07%
$25k-$35k	-6.03	-0.70%	-3.96	-0.83%	-2.60	-0.74%	-3.26	-0.93%	-2.24	-0.65%	-2.18	-0.85%
$35k-$75k	-30.36	-0.77%	-11.46	-0.71%	-7.14	-0.75%	-8.68	-0.76%	-9.95	-0.83%	-7.36	-0.97%
>$75k	-18.25	-0.31%	-12.48	-0.61%	-3.01	-0.36%	-5.10	-0.48%	-2.41	-0.31%	-4.26	-0.74%
Total	-66.32	-0.57%	-34.19	-0.74%	-18.11	-0.71%	-21.36	-0.73%	-20.11	-0.71%	-17.75	-0.93%

Table J-54. Distribution of Real Household Income (millions of dollars), 2045

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-2.48	-2.48%	-1.71	-3.22%	-1.51	-2.67%	-0.99	-2.76%	-1.45	-2.66%	-0.95	-2.84%
$10k-$15k	-3.24	-1.89%	-1.56	-1.94%	-1.43	-1.69%	-0.92	-1.95%	-1.71	-1.55%	-0.99	-1.82%
$15k-$25k	-8.75	-1.35%	-4.51	-1.31%	-3.76	-1.36%	-3.51	-1.30%	-3.92	-1.16%	-3.02	-1.36%
$25k-$35k	-7.76	-0.91%	-5.05	-1.06%	-3.39	-0.96%	-4.17	-1.18%	-3.03	-0.88%	-2.81	-1.09%
$35k-$75k	-39.53	-1.00%	-15.45	-0.96%	-9.47	-1.00%	-11.49	-1.01%	-13.41	-1.12%	-9.52	-1.25%
>$75k	-27.52	-0.47%	-18.10	-0.88%	-4.44	-0.53%	-7.24	-0.68%	-4.10	-0.53%	-5.69	-0.98%
Total	-89.29	-0.77%	-46.39	-1.01%	-23.99	-0.94%	-28.32	-0.97%	-27.62	-0.98%	-22.99	-1.21%

Table J-55. Distribution of Real Household Income (millions of dollars), 2050

Household Income	Metro		East		West		North		South		Central	
	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change	Amount	Percent Change
<$10k	-0.15	-0.15%	-1.25	-2.36%	-0.86	-1.52%	-0.35	-0.97%	-0.63	-1.16%	-0.56	-1.68%
$10k-$15k	-0.25	-0.15%	-0.97	-1.21%	0.40	0.47%	-0.23	-0.49%	0.45	0.41%	-0.39	-0.72%
$15k-$25k	7.68	1.18%	-0.35	-0.10%	2.82	1.02%	1.31	0.49%	5.95	1.77%	0.01	0.00%
$25k-$35k	15.99	1.87%	1.53	0.32%	5.46	1.55%	3.01	0.86%	6.83	1.99%	1.06	0.41%
$35k-$75k	105.91	2.69%	10.19	0.63%	19.84	2.09%	18.20	1.59%	28.91	2.41%	5.53	0.73%
>$75k	235.67	4.01%	14.01	0.68%	21.57	2.55%	23.50	2.21%	29.19	3.74%	5.87	1.01%
Total	364.84	3.15%	23.16	0.50%	49.24	1.92%	45.44	1.56%	70.71	2.50%	11.51	0.60%

Appendix K. GIS Maps of Temperature and Precipitation Change

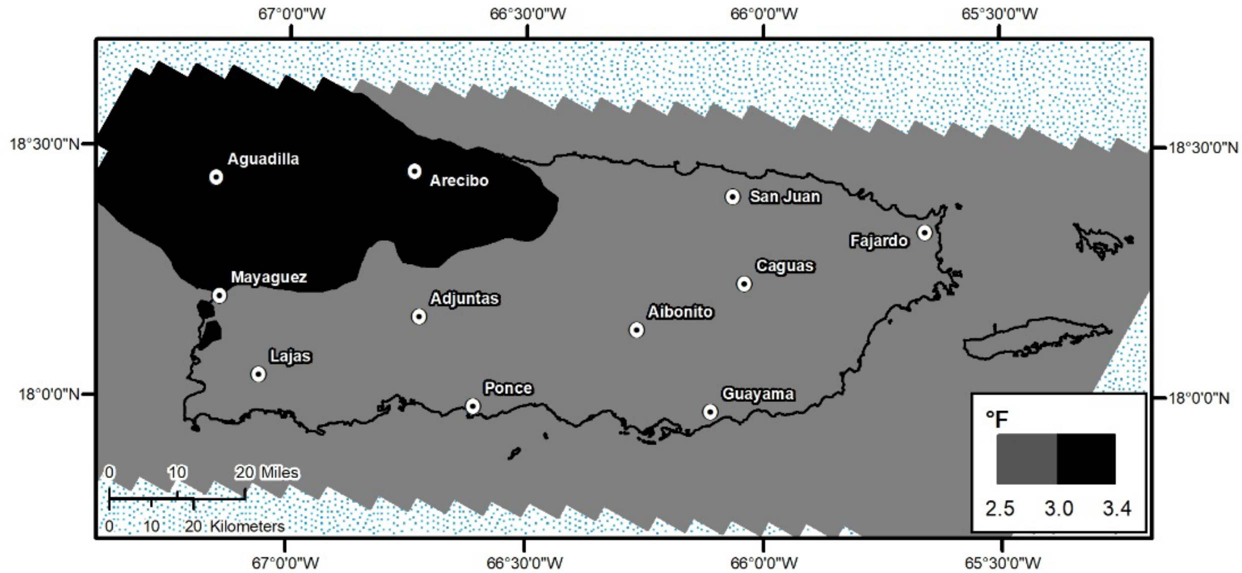


Figure K-1. Spring temperature increases, daily mean

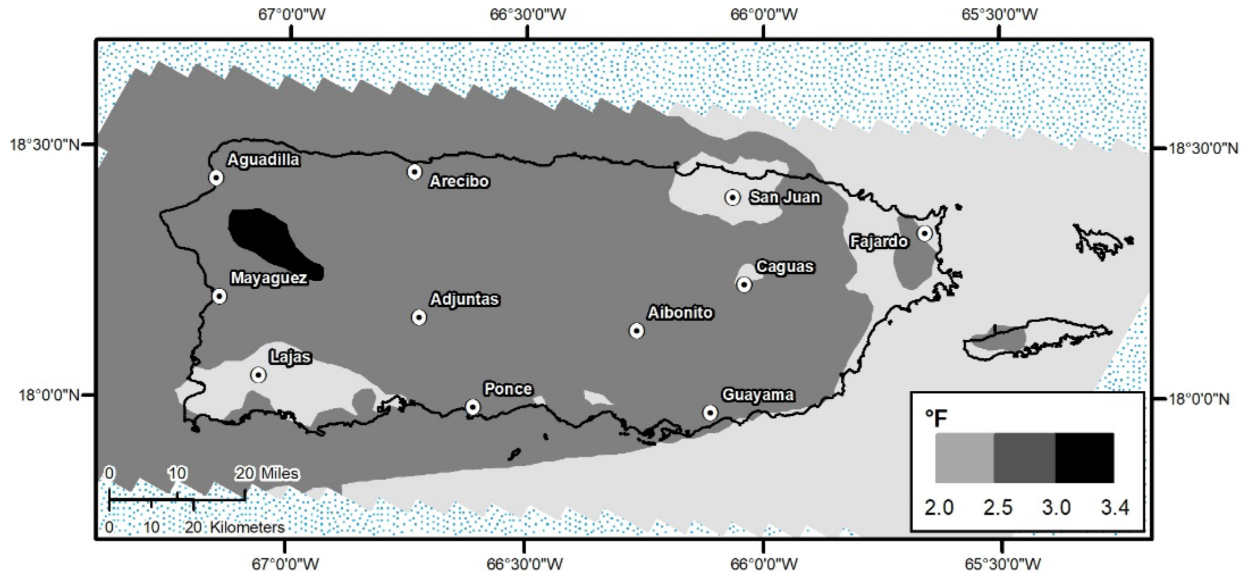


Figure K-2. Summer temperature increases, daily mean

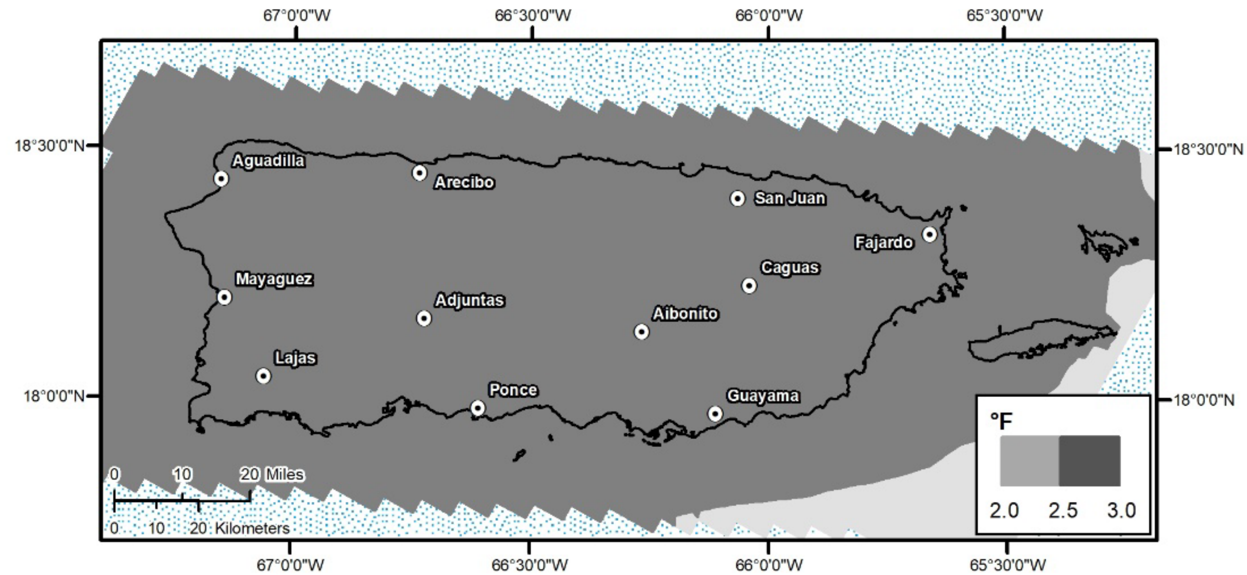


Figure K-3. Fall temperature increases, daily mean

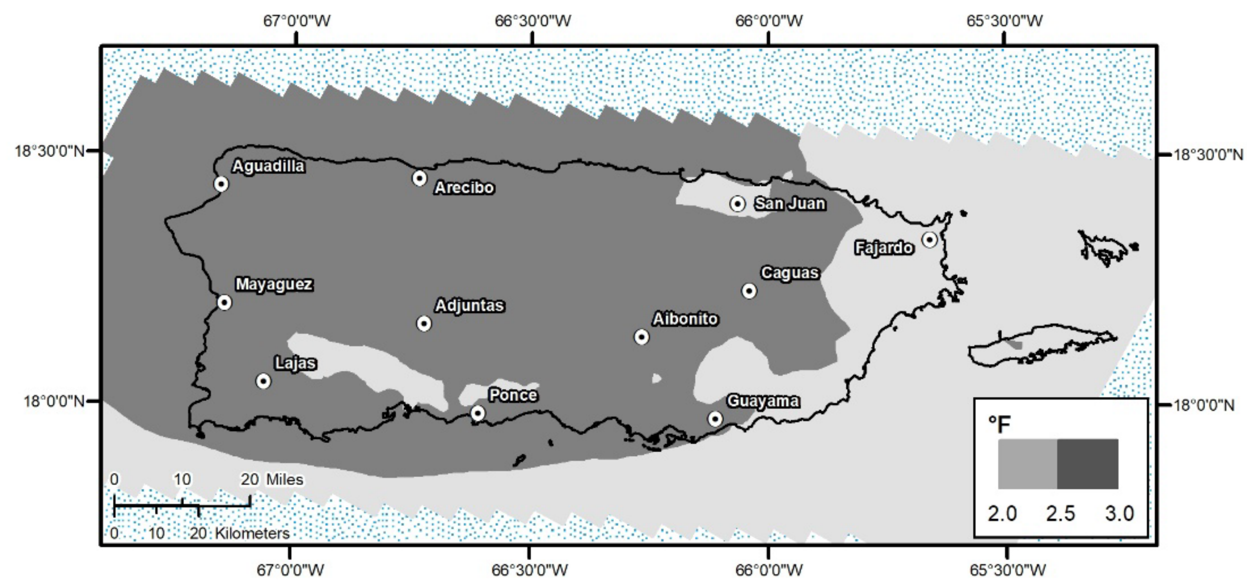


Figure K-4. Winter temperature increases, daily mean

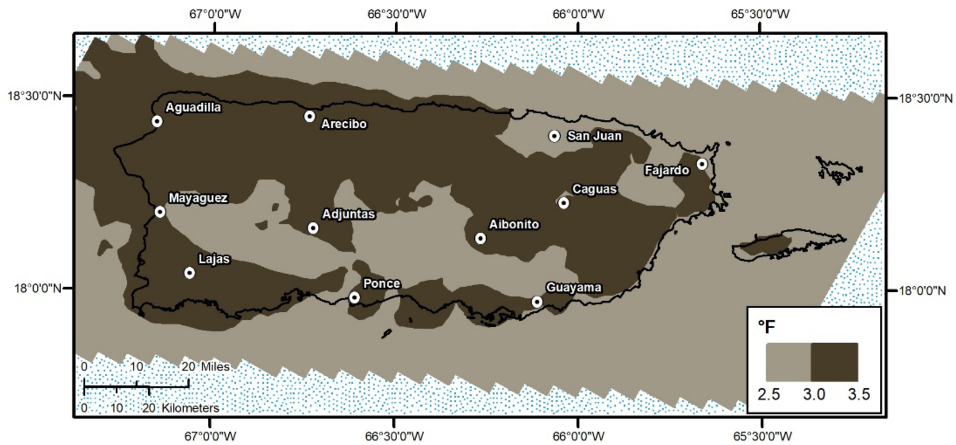


Figure K-5. Spring temperature increases, daily minimum

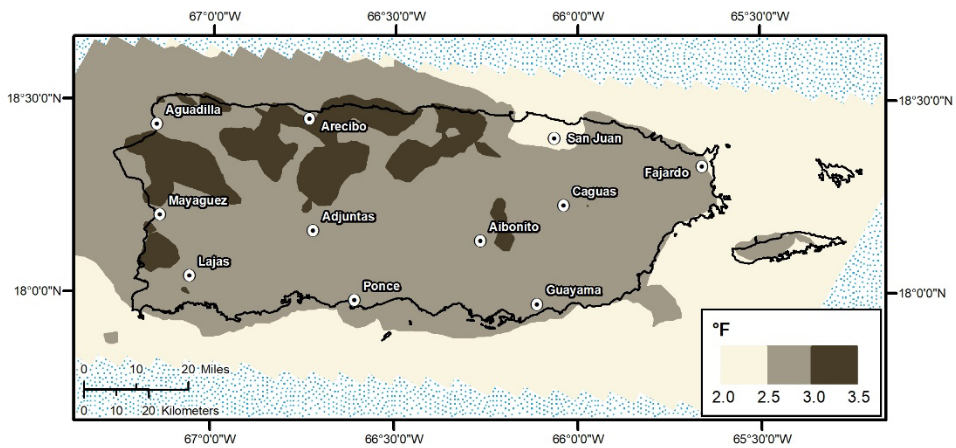
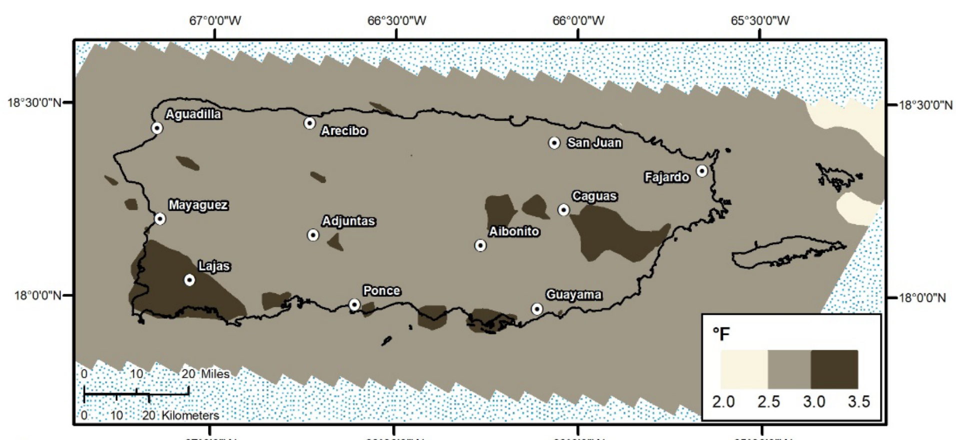


Figure K-6. Summer temperature increases, daily minimum



°F

Figure K-7. Fall temperature increases, daily minimum

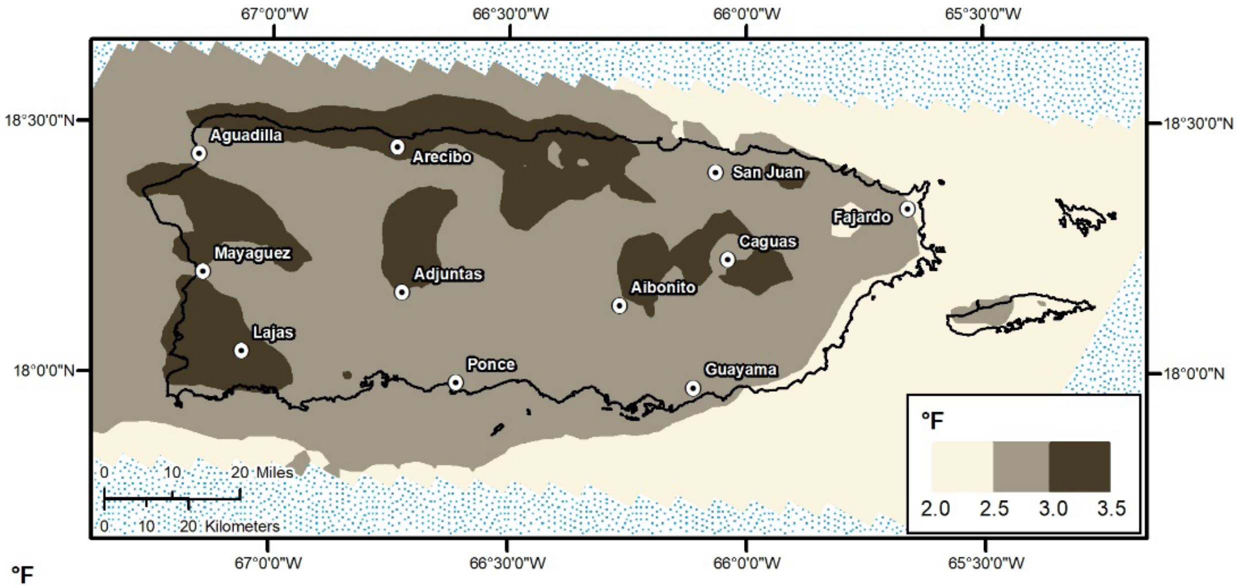


Figure K-8. Winter temperature increases, daily minimum

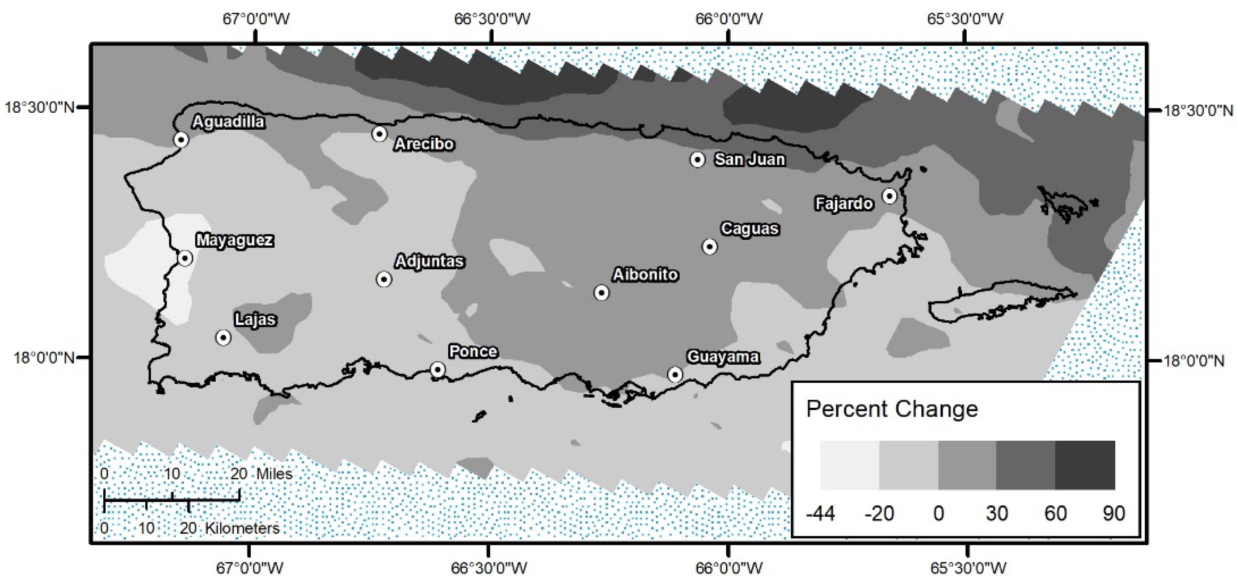


Figure K-9. Fall percentage change in precipitation

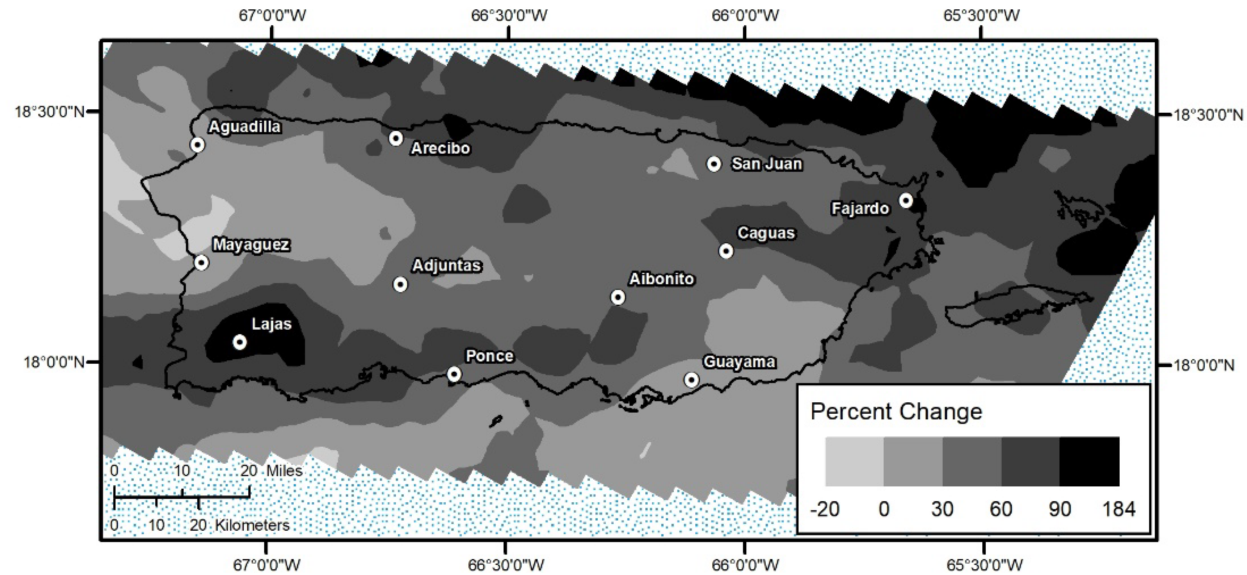


Figure K-10. Winter percentage change in precipitation

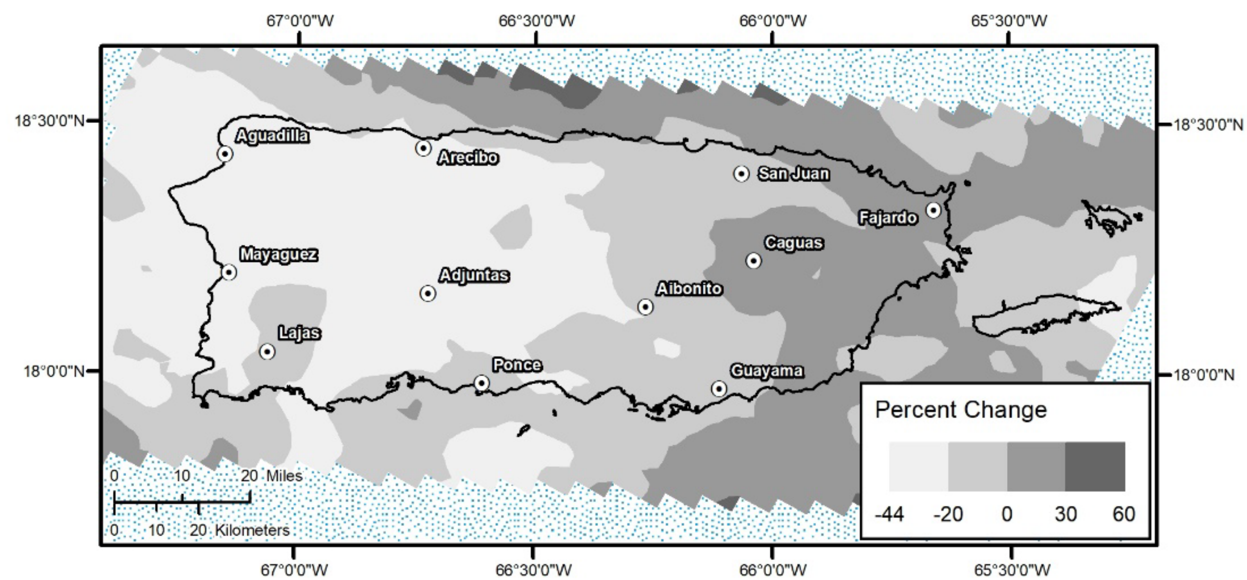


Figure K-11. Spring percentage change in precipitation

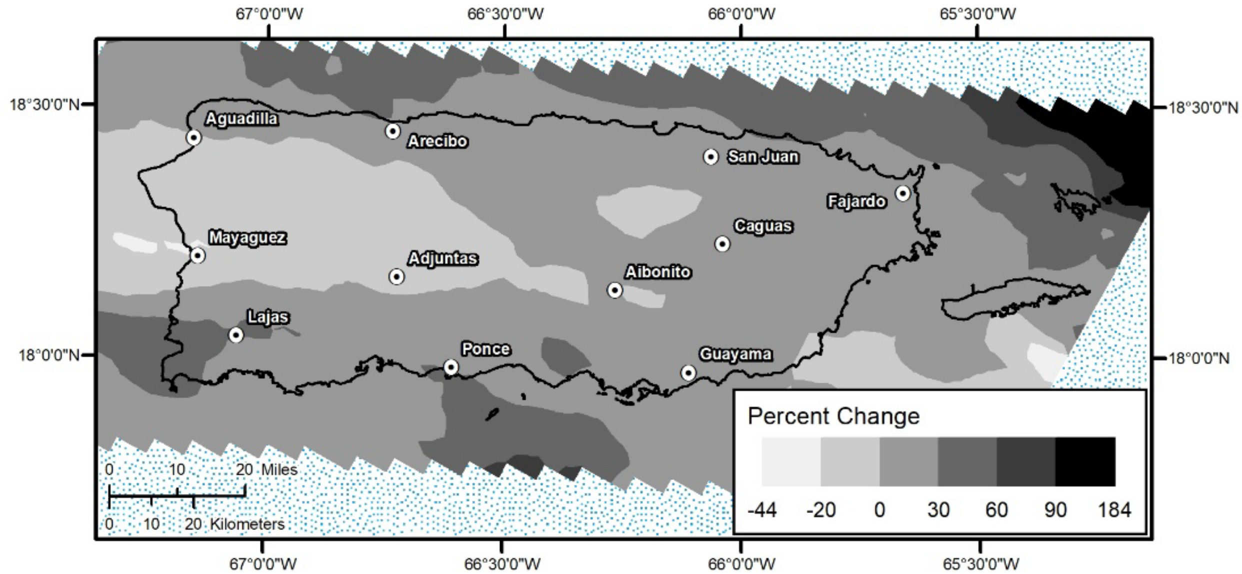


Figure K-12. Summer percentage change in precipitation

Appendix L. Data Handling

The challenge of coordinating the large-scale simulation runs of the ADDA was extraordinary and at the cutting edge of climate science research in terms of the scale of the simulations and the amount of data stored for the simulations. The full North America data set, from which the PR100 data were extracted as a subset, comprised such a large volume (≈1 PB) of output data that many special storage systems were needed and had to be coordinated. The size of the runs and the computational power and resources required to do them was also very large. Consequently, structuring runs and collecting and managing the output data from them was an engineering challenge.

During post-processing of the data, some problems were identified in the output of the precipitation data. The problems arose because of the simulation time-step. Under most conditions the simulation used an adaptive time-step strategy in which the Weather Research and Forecasting Model would adjust its time-step while conducting the calculation. However, when certain calculations encountered instability issues, a very small, fixed time-step was used. These two approaches should have given exactly the same solution, but they do not, and this disagreement generates different precipitation amounts between time periods when using the two different time-stepping strategies. This is a known problem reported to the WRF development team and to our best knowledge there is no update yet on this issue as of our writing. Because the precipitation amount from the WRF output is accumulated from the beginning of the simulation, such these differences would cause the tendency calculation ($P_t – P_{t-1}$, where t is one hour) to result in showing negative values if the output of P_t and P_{t-1} are from two time-stepping strategies. In particular, we have identified that October 1999 (first week) and February 2047 show the most disruption by this problem. Other months and years also show such issues but not at a significant amount (less than 5% of the data points in space and time).

For the analyses presented here, any simulation day with a negative hourly precipitation value was omitted from the analysis of precipitation. We have also removed the periods in 1999 and 2047 from calculation for all climate variables. For aggregation of all variables into seasonal values, winter 2046–2047 was eliminated from calculation, under the belief that missing nearly the entire final third of the season would skew that season's average toward the values for December and January, causing it to be nonrepresentative when compared to the sample of other winters. However, fall 1999 was not eliminated, because it was believed that substantial portions of the beginning of September and of the end of October were still intact and could be used to create a reasonable picture of that season. Scope did not permit the impact of these decisions to be measured through a full comparative analysis.

We also note that the issue is not specific to the Puerto Rico subset of the data; this is a global issue over entire North American domain. While there are more negative values in hourly precipitation data, when calculating daily or monthly or seasonal precipitation (still using $P_t – P_{t-1}$, but t is day or month here) from the accumulated output, such issue can be significantly reduced. Also note that this issue only affects certain time steps but not entire time period. The climate statistics from these simulations are still valid against observations. The diagnosis of the problems, and the necessary reruns of the simulation with a consistent time-stepping strategy, were not completed at the time of writing the final report. The corrected data will be modified and made available at a later time.

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