NEPR
Received:
Oct 31, 2024
11:54 AM

Puerto Rico Electrical System Resource Adequacy Analysis Report

October 31, 2024

Contents

Appendices

Figures

Tables

Acronyms and Abbreviations

Acronym/Abbreviation	Definition/Clarification
BESS	Battery Energy Storage System
BTM	Behind The Meter
CC	Combined Cycle
CPUC	California Public Utilities Commission
DER	Distributed Energy Resources
DG	Distributed Generation
DR	Demand Response
ELCC	Effective Load Carrying Capacity
ERM	Energy Reserve Margin
EUE	Expected Unserved Energy
EV	Electric Vehicle
FEMA	U.S. Federal Emergency Management Agency
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Council
FY2023	Fiscal Year 2023
FY2024	Fiscal Year 2024
FY2025	Fiscal Year 2025
GPA	Guam Power Authority
HECO	Hawaiian Electric Company
HPUC	Hawaii Public Utilities Commission
IPP	Independent Power Producer
IRM	Installed Reserve Margin
IRP	Integrated Resource Plan
ISO	Independent System Operator
LOLE	Loss of Load Expectation (days per year, multiple events in a single day count as 1 LOLE)
$LOLE_v$	Loss Of Load Expectation Event (could be multiple events in a single day)
LOLH	Loss Of Load Hours
LOLP	Loss Of Load Probability
LSE	Load Serving Entity

Acronym/Abbreviation	Definition/Clarification
LUMA	LUMA Energy [also, the “System Operator”]
MW	Megawatt
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NREL	U.S. National Renewable Energy Laboratory
PJM	Pennsylvania-New Jersey-Maryland (large grid operator on mainland U.S.)
PLEXOS	PLEXOS (a production cost model)
PPOA	Power Purchase and Operating Agreement
PRAS	Probabilistic Resource Adequacy Simulation (resource adequacy model)
PREB	Puerto Rico Energy Bureau
PREPA	Puerto Rico Electric Power Authority
PRM	Planning Reserve Margin
PV	Photovoltaic
USVI	U.S. Virgin Islands
V2G	Vehicle-to-Grid
VIWAPA	Virgin Islands Water and Power Authority
VPP	Virtual Power Plant
WWRT	Winter Weekly Reserve Target

Executive Summary

This report summarizes a set of analyses conducted by LUMA to assess the adequacy of current electricity supply resources in Puerto Rico to reliably serve anticipated electricity demands during the Fiscal Year July 1, 2024, to June 30, 2025 (FY 2025).

The report finds that the **power generation resources interconnected to Puerto Rico's electric grid are inadequate to provide electricity service at the degree of expected reliability for U.S. electric utilities**. Age and underinvestment have increased the downtime of the generation fleet and have reduced the maximum output that generators can provide when operational. With available capacity far lower than indicated by nameplate ratings, total supply resources frequently fall below levels that assure continuously reliable grid operation. In instances when power generation capacity falls below demand, the system operator must initiate load-shedding events, in which electricity service to selected customers is interrupted. Such capacity shortfalls are most prevalent during summer evening hours when electricity demand is highest.

Under Base Case conditions, it is expected that there will be 36 days during FY 2025 in which load-shedding events will be initiated in Puerto Rico due to inadequate resources, and that these load-shedding events total to an expected 154 hours of electricity service interruption for the average customer over the course of the year. The degree of expected load-shedding frequency and duration is far higher than the level of electric system performance used as a benchmark for planning purposes at most U.S. utilities. It is important to emphasize that presented values are averages that result from a set of statistical methodologies. The amount of load-shedding that occurs during FY 2025 will result from actual weather conditions and actual outages of power plants – future circumstances that are intrinsically unknown when these analyses were conducted, but for which these analyses provide reasonable indicators of expected Puerto Rico electric grid performance. During FY 2025, load-shedding events could occur on fewer than 36 days and aggregate to less than 154 hours, but it is equally likely that load-shed frequency and duration will exceed the indicated averages.

Multiple sensitivity analyses were conducted to provide a range in the potential variation in load-shedding outcomes. These sensitivity analyses indicated that the addition of 850 MW of "perfect" resources – which in practice equates to roughly 1,000 MW of new energy storage or generation capacity when asset downtime is considered – would improve resource adequacy in Puerto Rico to levels approaching U.S. mainland standards. On the other hand, the prolonged outage of a major power plant would make the current resource inadequacy dramatically worse.

Ultimately, **major improvements in Puerto Rico electricity resource adequacy cannot be expected unless and until resource supply is materially increased** through either new resource additions or major improvements to the existing power generation fleet**.** Resource additions require both major capital investment and a long time to complete, and major power plant improvements cannot be accomplished without lengthy outages that would worsen resource adequacy in the interim. As a result, **Puerto Rico's resource adequacy deficiencies will not be easily remedied. Expectations about future improvements in resource adequacy should be set accordingly**.

Background

Although the aggregate "nameplate" (i.e., rated) capacity of the current Puerto Rico generation fleet is substantially higher (5,749 MW) than peak electricity demand (3,414 MW achieved in June 2023), **Puerto Rico does not have sufficient generating capacity.**

Total capacity available in any given hour to supply electricity to Puerto Rico customers is always substantially lower than aggregate nameplate capacity.

Most generators in Puerto Rico have a "net dependable" capacity – the amount that a generating facility can reliably deliver to the grid – that is below the nameplate capacity rating. **Whereas total nameplate capacity of the Puerto Rico thermal power plant fleet exceeds 5,300 MW, its total net dependable capacity is less than 4,300 MW**. In addition, existing generating facilities in Puerto Rico are often not operational, and concurrent unplanned outages at multiple power plants are common.

The two generation issues described above are especially pronounced in Puerto Rico for two primary reasons. First, **some generation units in the thermal power plant fleet are so degraded from historical lack of maintenance and underinvestment that they are only able to deliver a fraction of their nameplate capacity.** Second, also due to age and underinvestment, **most generation facilities in Puerto Rico are more unreliable than comparable power plants elsewhere and thus are often unavailable to operate**.

Therefore, the total capacity of generation resources available to produce electricity in Puerto Rico is always lower than rated capacity levels would indicate. Indeed, during certain hours, available generation capacity is less than electricity demand on the island. When **generation shortfalls occur, the system operator must initiate "load shed" events in which electricity service is interrupted to selected customers** in order to equalize demand with available supply. Load-shedding at these times is necessary to avoid more widespread disruption of electricity service.

LUMA's Commitment to Supporting Resource Additions

Since assuming operational responsibility for the Puerto Rico electric grid in June 2021, LUMA has consistently found that Puerto Rico has inadequate supply resources to deliver reasonable system reliability – and has communicated this to the Puerto Rico Energy Board, the Government of Puerto Rico, and public stakeholders.

Even though LUMA does not own or operate any generation facilities, LUMA is committed to doing everything possible within its scope of responsibilities to address Puerto Rico's long-standing generation capacity issues. LUMA knows that any interruption of electricity service causes disruption, inconvenience and hardship for customers, and LUMA is working to eliminate the occurrence of interruptions due to insufficient energy resources. For example, LUMA has been actively working with power generators, the Government of Puerto Rico, and U.S. Federal agencies to increase the amount of generation to improve system reliability. LUMA's efforts to support increased generation capacity on behalf of its customers include but are not limited to:

- **Advocating for Emergency Generation:** Working with key stakeholders, LUMA advocated for the rapid deployment of emergency generation to augment the deficient supply on the Puerto Rico electricity grid in the wake of Hurricane Fiona. In less than a year, this effort led to FEMA-funded trailer-mounted (TM) generators deployed in Puerto Rico. In March 2024, PREPA acquired most of the TM generators to be operated by Genera PR beyond the emergency period. These 340 MW of TM generation are now considered a critical part of Puerto Rico's electricity system.

- **Advancing Large-Scale Renewable Projects:** LUMA is actively working with renewable energy developers, investors and the Government of Puerto Rico to interconnect large-scale solar photovoltaic (PV) projects to add new capacity to the grid, increase the amount of renewable energy resources, and help build a world-class electric system that will reliably serve Puerto Rico for decades to come.

- **Expanding Distributed Clean, Renewable Energy Resources:** LUMA is interconnecting rooftop solar systems for approximately 3,650 customers per month, an unprecedented rate in Puerto Rico. As of May 31, 2024, LUMA has worked with over 118,000 customers to support the installation of rooftop PV systems, adding more than 860 MW of clean energy sources to the electric grid, and propelling Puerto Rico to rank 5th in solar adoption per capita among all U.S. states and territories.

- **Adding Battery Energy Storage Systems:** LUMA has been collaborating with stakeholders on the addition of both utility-scale and distributed battery energy storage resources to increase the supply of energy available on the Puerto Rico electric grid during peak demand periods, thereby reducing the need to implement load shedding. For instance, the **Customer Battery Energy Sharing (CBES)** initiative, a pilot program designed to leverage customer-sited battery storage systems, has yielded the largest "virtual power plant" (VPP) in the Caribbean, with LUMA acting ahead of most other U.S. utilities to harness the VPP potential afforded by distributed energy storage assets. As another example, the **Accelerated Storage Addition Program (ASAP)** is fast-tracking the installation of battery energy storage systems at existing power generation facilities in Puerto Rico. The CBES program has already reduced load-shed events in Puerto Rico, and the future expansion of CBES along with the successful implementation of ASAP will make load shed events in Puerto Rico infrequent.

Key Findings

This resource adequacy report estimates the probabilistic risk of insufficient electricity supply to meet the demands of Puerto Rico's electric customers. The report is centered on a "Base Case" assessment, which presents an average expectation of electricity resource adequacy in Puerto Rico for FY2025 under the current configuration of the electricity grid. In addition, a Force Majeure Scenario and multiple other sensitivity analyses were also undertaken to reveal the potential implications on resource adequacy if electricity supply resources or electricity demand levels in Puerto Rico during FY 2025 were to be higher or lower than assumed for the Base Case.

Key findings discussed in greater detail in the balance of this report include:

In the Base Case assessment, **estimated Loss of Load Expectation (LOLE) is 36.2 days per year**. This means that, in Puerto Rico, electricity service interruptions due to insufficient electricity supplies should be expected, on average, on 36.2 days during FY 2025. This level of **LOLE for Puerto Rico is 362 times higher than the target level** (LOLE of 0.1 days per year) used as a typical benchmark for planning purposes at many U.S. utilities. A LOLE of 36.2 days per year equates to approximately 3 days per month in which load-shed events can be expected in Puerto Rico, which is consistent with historical load-shed data from the previous 12 months.

While it remains unacceptably high and substantially above industry standard levels, **estimated LOLE under anticipated conditions assumed for the Base Case represents an improvement since LUMA's 2022 resource adequacy report**, down to 36.2 days/year from 50 days/year. This improvement is largely due to 340 MW of TM generation added after Hurricane Fiona, which has meaningfully reduced the risk of insufficient generation.

In the Base Case, loss of load hours (LOLH) – the average number of hours during FY 2025 when Puerto Rico electricity supply will be deficient to serve load and load-shedding would occur – is estimated to be 154.2 hours. **An LOLH of 154.2 hours is 64 times higher than the utility industry standard**.

Generation insufficiency (and hence load-shedding) most frequently occurs during the evening hours (6 pm – 10 pm) between the months of July and October when system demand achieves peak levels. During these hours, system load often approaches or exceeds 3,000 MW, whereas Puerto Rico's available generation capacity rarely exceeds 3,000 MW, often resulting in capacity reserve margins below the threshold level that the system operator aims to always maintain to ensure reliable grid operations.

As shown in Table ES-1, the results from both the Force Majeure Scenario and several other sensitivity analyses indicate that **any prolonged reduction in power generation capacity (such as a long-lasting outage at a major power plant unit) dramatically worsens resource adequacy** – resulting in LOLE and LOLH values far higher than estimated under the Base Case.

Table ES-1: Resource Adequacy Measures With Reduced Power Generation Capacity

Scenario	Loss of Load Expectation (LOLE) days/year	Loss of Load Hours (LOLH) hours/year
Base Case	36.2	154.2
Force Majeure Scenario	66.7	339.9
Sensitivity: Unavailability of emergency generation	120.4	694.9
Sensitivity: Unavailability of Costa Sur 6	106.4	555.3
Sensitivity: Unavailability of AES	140.4	860.0

The extended loss of a major power plant is entirely consistent with recent experience in Puerto Rico. Note that Costa Sur 6**,** one of the largest power plants on Puerto Rico (350 MW), did not operate for over a year following the January 2020 earthquake. Other large power plant units, such as Aguirre 1 (300 MW), have been taken out of service for months at a time.

Assuming existing generation resources in Puerto Rico continue to be available at least at recent levels of performance, the addition of dependable bulk supply resources reduces the risk of generation shortfalls. Under Base Case assumptions, **the addition of 850 MW of "perfect" (i.e., always available) generation capacity would cause Puerto Rico resource adequacy (as measured by LOLE) to attain U.S. mainland levels**. Note that the analyses presented herein do not evaluate the types of incremental supply resources to be installed, estimate costs of new resources, or address policy impacts associated with resource expansion. These matters will be considered in the upcoming Integrated Resource Plan (IRP) currently under development by LUMA.

As shown in Table ES-2, the addition of battery storage assets would significantly increase grid reliability and reduce load shed impacts to customers.

Table ES-2: Resource Adequacy Measures
With Addition of Standalone Energy Storage

Scenario	Loss of Load Expectation (LOLE) days/year	Loss of Load Hours (LOLH) hours/year
Base Case	36.2	154.2
Sensitivity: Tranche 1 BESS-only projects	8.1	33.3
Sensitivity: ASAP BESS project	9.5	45.3
Sensitivity: Genera's BESS projects	5.6	22.0
Sensitivity: LUMA's 4x25 BESS project	23.4	105.4
Sensitivity: Tranche 1 + ASAP + Genera + 4x25 projects	0.1	0.2

Under Base Case assumptions, it is estimated that **the addition of 1,240 MW of energy storage assets would cause Puerto Rico resource adequacy (as measured by LOLE) to attain U.S. mainland levels**.

It is important to caveat the expected benefit of resource additions. **Absent the installation of energy storage capabilities, further additions of solar capacity will have only a relatively modest ability to improve resource adequacy in Puerto Rico**, as shown in Table ES-3. This is because peak electricity demands and projected shortfalls in capacity usually occur in the early evening after the sun has set and solar output falls to zero.

Table ES-3: Resource Adequacy Measures With Addition of Standalone Solar Projects

Scenario	Loss of Load Expectation (LOLE) days/year	Loss of Load Hours (LOLH) hours/year
Base Case	36.2	154.2
Sensitivity: Non-tranche + Tranche 1 solar-only projects	34.3	124.3
Sensitivity: Additional distributed solar PV	35.6	147.0

Resource adequacy is not only dependent on supply resources but will also vary with the level of electricity demand. To improve resource adequacy, in addition to increasing customer outreach concerning energy efficiency and conservation to reduce electricity demand levels generally, LUMA is working on a Demand Response (DR) program that would initiate load reductions at the request of the system operator on an as-needed basis.

Higher than expected customer load growth (which could be caused, for example, by widespread adoption of electric vehicles) can significantly increase the risk of generation-shortfall load shed events due to capacity being insufficient to serve higher load levels. As shown in Table ES-4, **a 10% increase in load worsens resource adequacy far more than a 10% reduction in electricity demand improves resource adequacy**.

Table ES-4: Resource Adequacy Measures With Changes in Puerto Rico Electricity Demand

Scenario	Loss of Load Expectation (LOLE) days/year	Loss of Load Hours (LOLH) hours/year
Base Case	36.2	154.2
Sensitivity: 10% hour-by-hour load increase	96.9	501.3
Sensitivity: 10% hour-by-hour load decrease	8.8	32.0

Ultimately, **major improvements in Puerto Rico electricity resource adequacy cannot be expected unless and until resource supply is materially increased**. In turn, resource supply can only be increased by a combination of new capacity additions and improvements to the existing thermal power plant fleet.

New resource additions require both major capital investment and a long time to complete, involving regulatory approvals, equipment procurement and delivery, project construction, and interconnection to the grid. The timelines associated with the completion of Tranche 1 renewable energy projects are instructive.

Meanwhile, improvements to the existing Puerto Rico thermal power plant should be pursued as much as reasonably possible. If all the existing generation facilities in Puerto Rico were as reliable as those found at most other U.S. utilities, Puerto Rico's resource adequacy would be significantly better than is currently the case. Many improvements may be economically attractive to undertake purely on financial merit. Alas, **major power plant improvements generally cannot be accomplished without lengthy outages, thereby exacerbating resource inadequacy during the interim**.

Roles and Responsibilities

The legal framework for the electric system established by Act 17-2019 and Act 57-2014 provides for the disaggregation of the Puerto Rico electric system functions, including the division of generation from transmission and distribution activities. Accordingly, and in accordance with Act 120-2018, as amended by Act 17-2019, today, these utility functions have been delegated. Genera PR is responsible for the operation and maintenance of PREPA-owned generation facilities, while other private generation facilities are operated and maintained by independent power producers. Meanwhile, LUMA is responsible for overall electric system operations and transmission and distribution activities, including systemwide coordination, planning and analyses.

LUMA's responsibilities are stipulated by the Puerto Rico Transmission and Distribution Operation and Maintenance Agreement between the Puerto Rico Electric Power Authority (PREPA), the Public Private Partnerships Authority (P3 Authority), LUMA Energy, LLC and LUMA Energy ServCo (collectively, LUMA) effective June 21, 2020 (T&D OMA). As part of these responsibilities, LUMA carries out multiple activities to improve the reliability and resilience of the Puerto Rico electric system. Among these activities are conducting studies to assess resource adequacy for the electric system to meet the energy demands of Puerto Rico. LUMA does not generate electricity. As the system operator for Puerto Rico, LUMA carefully monitors and dispatches available generation resources – operated by Genera PR, EcoEléctrica, AES and others – to meet customer demand and ensure the reliability of the overall electric system.

This report presents an updated set of analyses regularly conducted by LUMA to evaluate electricity resource adequacy in Puerto Rico. These analyses enable deeper insight into the drivers of historical performance of the Puerto Rico electric grid and to support strategic decisions that will shape the Puerto Rico electric system for decades to come.

LUMA is committed to doing everything it reasonably can to improve the Puerto Rico electric system, and this resource adequacy assessment makes a significant contribution by providing information to help stakeholders involved in the Puerto Rico electricity industry make better decisions.

Integrated Resource Plan

As previously stated, LUMA does not own or operate any generation facilities. However, LUMA is responsible for resource planning, including Integrated Resource Plans (IRP) conducted under the Energy Bureau's purview.

Based on the IRP developed by PREPA (prior to LUMA's assumption of responsibilities) in Case No. CEPR-AP-2018-0001, *In Re: Review of Puerto Rico Electric Power Authority Integrated Resource Plan*, the Energy Bureau approved a Modified Action Plan in August 2020. LUMA is currently preparing the 2024 IRP, which will guide the transformation of the island's energy resources over the next two decades to achieve a more resilient, cleaner, and sustainable electric system and help reduce generation shortfalls in the future. The 2024 IRP will be submitted to and reviewed by the Energy Bureau in Case No. *NEPR-AP-2023-0004*, *In Re: Review of the Puerto Rico Electric Power Authority Integrated Resource Plan*. In turn, this resource adequacy report provides important inputs into the 2024 IRP.

This report is also intended to support to processes and discussions overseen by the Energy Bureau, which will help determine how Puerto Rico can reduce the risk of insufficient generation supply to meet energy demand. LUMA is committed to working with the government, generators, and the Energy Bureau to address these systemic generation issues to provide the people of Puerto Rico with safe, reliable, and clean energy. While this report supports decision-making regarding generation retirements, additions, modifications, maintenance schedules, and other items to reduce the risk of insufficient electric supply, specific recommendations on generation capacity additions (including determining which technologies are the best suited to meet the system needs most effectively) are the subject of the IRP process underway in parallel to this report.

Report Scope and Methodology

At a high level, resource adequacy analyses quantify the risk that an electricity system is unable to serve system load because of insufficient generation capacity. Electricity system resource adequacy guidelines are based on regulatory requirements, system operator policies, and best utility practices. Many of these policies have been set by the U.S. Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), state/territory governments, and regional regulating authorities.

Although FERC, NERC and other state regulators and governments have no jurisdiction over the Puerto Rico electricity system, the resource adequacy practices that have resulted from their collective work represent best practices that LUMA believes should be used for assessing the reliability of the Puerto Rico electricity grid. Consequently, the methodology followed in this report is consistent with this collective body of work. Resource adequacy methodology is discussed further at a general level in Section 1 of this report, and further details of the methodology used in this resource adequacy report are presented in Appendix C.

This analysis covers Fiscal Year 2025 (FY2025), which spans from July 1, 2024, to June 30, 2025. Data and assumptions used in the analysis are based on historical information gathered from the Puerto Rico electricity system, augmented as necessary by information from sources outside of Puerto Rico. Details about data sources and assumptions made and utilized in the resource adequacy analyses are presented in Appendix B.

The report is presented below in the following sections:

- Section 1 introduces the key concepts underlying electricity resource adequacy analysis.
- Section 2 provides an overview of the Puerto Rico electricity system, including a summary of both supply (generation) and demand (load).
- Section 3 concludes the report by presenting the results from multiple resource adequacy analyses – including the Base Case, the Force Majeure Scenario, and 20 sensitivity analyses in which various assumptions about electricity supply and demand in Puerto Rico are varied for analytical purposes.

The report is supported with three Appendices.

- Appendix A provides detailed results from the 20 sensitivity analyses that were conducted as variants from the Base Case.
- Appendix B provides key assumptions on power generation resources, electricity demand and energy storage for Puerto Rico that were used in the modeling analyses.
- Appendix C provides further detail and description of resource adequacy practices employed in the electric utility industry.

1.0 Introduction to Resource Adequacy Analysis

This section provides a general overview of the methodology used for performing resource adequacy analyses, with additional commentary on how industry-standard resource adequacy methodology should be applied to assess generation adequacy in Puerto Rico. A deeper level of detail on resource adequacy concepts and methodologies is presented in Appendix C.

Generation resource adequacy analysis is focused specifically on determining the degree of generation deficiency across a regional electricity system, not on any intra-regional constraints associated with transmission and distribution systems. Consequently, this report will not discuss the implications on electricity reliability in Puerto Rico due to the state of its transmission and distribution network. Any transmission and distribution constraints will further reduce system reliability beyond any deficiencies in generation resource adequacy described herein.

This report focuses on resource adequacy in Puerto Rico assuming normal system operating conditions. Resource adequacy performance can also be analyzed for non-normal or adverse operating conditions, such as hurricanes, tropical storms, earthquakes, and other similar disasters. An industry term typically associated with infrastructure preparedness and performance during and after adverse operating conditions is "resiliency." As such, a resilient system is designed not only to be able to withstand adverse operating conditions, but also to be able to recover quickly. Robust resiliency planning is essential to help minimize the negative impact of a high-severity event. This is especially true on an island since it is not possible to import electricity from a neighbor in the aftermath of a disaster.

While evaluating electrical system resiliency in the face of adverse operating conditions is not a focus of this report, generation resource adequacy is an important part of resiliency planning, and the tools and methodology presented in this report can be used to help quantify the effectiveness of resiliency measures. (There is a separate work stream related to electricity system resiliency in Puerto Rico currently being supported by the U.S. Federal Emergency Management Agency.)

1.1 Resource Adequacy in the Electricity Industry

The focus of generation resource adequacy modeling is to determine if enough generation capacity is available to serve system load during every hour of the study period. This information provides regulators with the quantitative tools and measures to help ensure customers will receive safe and reliable power supplies. A resource adequacy analysis determines if there is a deficit in generation resources relative to what is necessary to assure a targeted level of adequacy for good electricity service., The results of resource adequacy analysis are then used in resource planning – such as an integrated resource planning (IRP) process – to develop a plan detailing recommended resource additions. The regulator and other policymakers must then approve the plan to address any anticipated generation shortfalls.

Resource adequacy analyses quantify the risk that an electricity system will be unable to serve system load based on current generation capacity. Resource adequacy guidelines for utilities are influenced by numerous agencies, including the U.S. Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), state/territory governments, and other regional regulating authorities. Although FERC, NERC and other state regulators and governments have no jurisdiction over the Puerto Rico electricity system, the resource adequacy practices that have resulted from their collective body of work represent best practices that LUMA believes should be used for assessing the reliability of the Puerto Rico electricity grid. The analyses presented in this document reflect good industry practices in resource adequacy modeling.

Any evaluation of system resource adequacy is rooted in a probabilistic approach to quantify the risk that system generators will be unable to fully serve system load. The analysis considers several important variables, such as power plant generation capacity, generation facility derates and outage rates, generation intermittency, and system electricity load, among other items.

There is a consistent set of fundamental guidelines for performing resource adequacy analyses across the electricity industry; however, there can be some variation in the analysis methodology based on the specific utility or planning region. In general, the key fundamentals of resource adequacy analyses can be summarized in the following points below:

- The goal of a resource adequacy analysis is to quantify how well the existing power plants in an electricity system are reliably able to serve system load.
- The analysis calculates the estimated probability, or risk, that system load might not be met by the generators delivering electricity to the system.
- Results from the probabilistic analyses are compared to a resource adequacy "target", which is defined as the acceptable level of risk that the generation portfolio might not be able to serve system load. The resource adequacy target is typically set by the regional electricity planning authority, consistent with guidance provided by the electricity regulator.

The results and implications of a resource adequacy analysis are important tools that planners can use to help make decisions about generation retirements, additions, or other programs related to how a utility can better serve system load. Resource adequacy requirements and calculations are often incorporated into integrated resource plans (IRPs), which are detailed planning initiatives undertaken by a utility to recommend investments in new projects or programs to increase system resources to meet future expected needs. IRP results are reviewed and approved (with modifications as necessary) by regulators for subsequent implementation. Currently, LUMA is nearing completion of an updated IRP to be presented shortly to the PREB and other Puerto Rico stakeholders for review and discussion.

Fundamentally, resource adequacy assessments involve the development of quantitative estimates of the probability that generation supply will be insufficient to serve system load. Note that an indicated resource deficiency does not mean the entire electricity system will go down, blacking out service to all customers. Instead, it signifies that there is not enough generation to serve system load, and that some customers will experience electricity outages.

The results of resource adequacy analyses are typically described by using one or more metrics that aim to capture key concepts associated with the possible loss of electricity service. Three resource adequacy metrics are commonly used:

- **Loss of load probability (LOLP):** the estimated probability (between 0 and 100%) that generation supplies will be inadequate to meet demand at least once over a defined period
- **Loss of load hours (LOLH):** the estimated number of hours over a defined period that generation supplies will be inadequate to meet demand
- **Loss of load expectation (LOLE):** the estimated number of days over a defined period that generation supplies will be inadequate to meet demand at least once during that day

These metrics represent different aspects of a system's reliability, encompassing the frequency, duration, and magnitude of generation shortfalls. A higher value for any of these metrics indicates an electricity system that will experience more instances in which generation supplies are inadequate. Accordingly, "target" levels of resource adequacy for an electric utility are usually defined by a maximum acceptable value for one or more of these metrics, such that the electricity system will be assessed to have resource adequacy only if the metric reported from the analysis is below its target level.

For the most part, the analyses presented in this report reference LOLE and LOLH. LOLE is an especially useful metric because, as shown in Table 1-1 below[1], common practice in the U.S. electricity industry is for utility resource adequacy to be deemed sufficient when LOLE is estimated to be no higher than 0.1 days per year (in other words, there is a 10% probability of a load-shed event in any given year).

[1] See EPRI Resource Adequacy Practices and Standards for a list of LOLE targets used in US system planning, https://msites.epri.com/resource-adequacy/metrics/practices-and-standards.

Table 1-1: Resource Adequacy Planning Standards Employed Regionally in U.S. Electric Utility Industry

Country or Region	RA MetricsCriteria	Entity Calculating RA Metric
North America [1],[2]		
MISO	LOLE ≤ 0.1 days/year	MISO
MRO-Manitoba Hydro	LOLE ≤ 0.1 days/year	Manitoba Public Utilities Board
NPCC-Maritimes	LOLE ≤ 0.1 days/year	Maritimes Sub-areas and NPCC
NPCC-New England	LOLE ≤ 0.1 days/year	ISO-NE and NPCC
NPCC-New York	LOLE ≤ 0.1 days/year	NYSRC and NPCC
NPCC-Ontario	LOLE ≤ 0.1 days/year	IESO and NPCC
NPCC-Québec	LOLE ≤ 0.1 days/year	Hydro-Québec and NPCC
PJM Interconnection	LOLE ≤ 0.1 days/year	PJM Board of Managers
SERC-C	LOLE ≤ 0.1 days/year	Member Utilities
SERC-E	LOLE ≤ 0.1 days/year	Member Utilities
SERC-FP	LOLE ≤ 0.1 days/year	Florida Public Service Commission
SERC-SE	LOLE ≤ 0.1 days/year	Member Utilities
SPP	LOLE ≤ 0.1 days/year	SPP RTO Staff and Stakeholders
TRE-ERCOT [1]	LOLE ≤ 0.1 days/year	ERCOT Board of Directors
WECC-AB	LOLP [2] ≤ 0.02%	WECC
WECC-BC	LOLP ≤ 0.02%	WECC
WECC-NWPP-US & RMRG [3]	LOLE ≤ 0.1 days/year	WECC
WECC-SRSG	LOLP ≤ 0.02%	WECC
WECC-CAMX [4]	PRM ≥ 15%	CPUC
	Additional local and flexible RA requirements	
Hawaii [5]	ERM ≥ 30% (3 islands), 60% (2 islands)	HECO

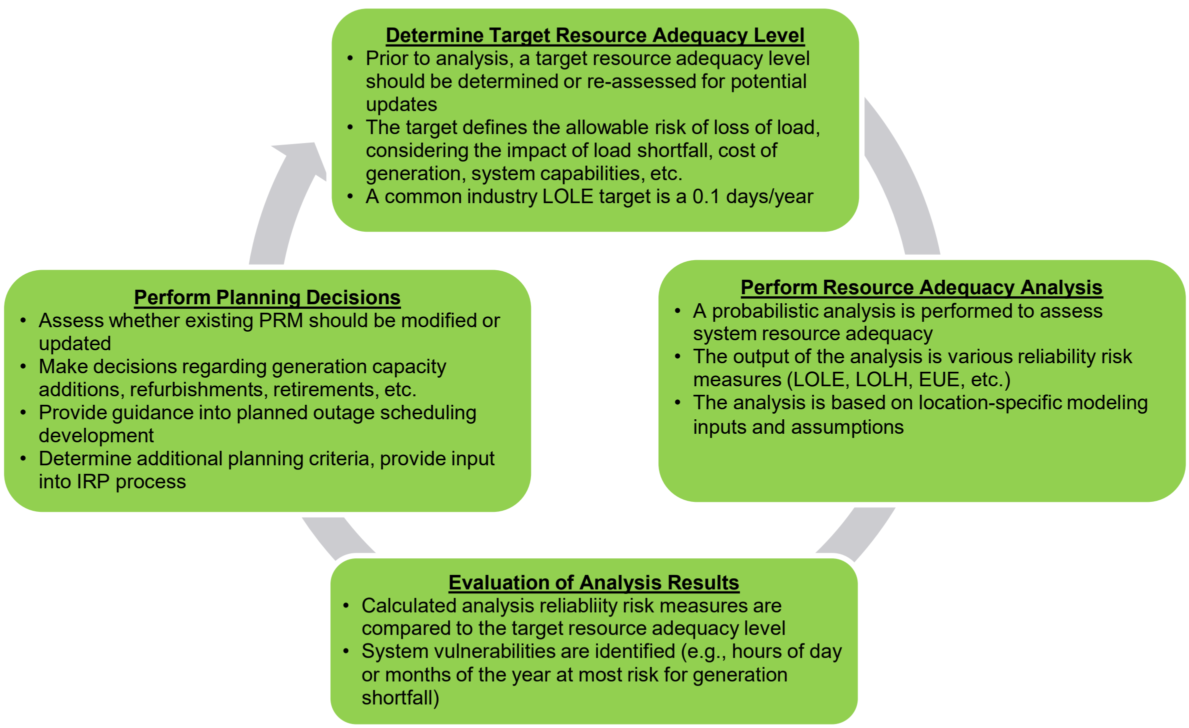
Support for probability-based resource adequacy assessments has increased due to changing electricity load profiles (e.g., the addition of customer-sited rooftop solar, the adoption of electric vehicles), the growth of intermittent renewable resources (e.g., solar and wind), and other factors that affect resource adequacy. Recent NERC surveys[2] indicate that most regional electricity systems in North America are

[2] North American Electric Reliability Corporation, Probabilistic Adequacy and Measures, July 2018.

using probabilistic approaches to examine resource adequacy questions, and if they are not, they are considering incorporating probabilistic approaches.

The basic steps involved in performing a resource adequacy analysis are depicted in Figure 1-1. The first step is to identify the target level of the preferred resource adequacy metric(s) to be achieved in the resource adequacy analysis. In the second step, probabilistic modeling is used to calculate the expected resource adequacy that will be achieved, based on data and assumptions about the electricity system's supply and demand. The third step compares estimated resource adequacy against a target level of resource adequacy to identify potential shortfalls in expected resource adequacy, and spotlight potential causes and circumstances under which resources will be inadequate. Finally, generation additions, retirements, and other programs can be recommended to improve resource adequacy.

Figure 1-1: Resource Adequacy Process Flowchart



Of the above-noted four steps, the second step involving the quantitative estimation of resource adequacy merits additional discussion here. Multiple analytic tools are used to conduct resource adequacy modeling in the industry, including spreadsheet-based tools, production cost modeling software, and commercial simulation software tools. In turn, these tools are critically dependent upon numerous assumptions about both supply and demand on the electricity system being evaluated. The probabilistic estimation of resource adequacy results from the following three activities:

- Demand levels for each of the 8,760 hours in a year are estimated for an upcoming year, using historical data as a baseline, adjusting for any abnormal weather conditions and adding forecasted growth from the historical year to the future year.

- For each of the 8,760 hours in a year, accounting for power plant outage rates and outage durations, the many possible permutations of aggregate generation supply availability in any given hour are considered, and a probability is calculated for each permutation to occur in what is called a Monte Carlo simulation.

- Each of the supply permutations in a given hour and its probability of occurring is evaluated against expected demand in that hour to calculate the fraction of possible outcomes in which supply will not be adequate to meet demand.

1.2 Industry-Wide Resource Adequacy Trends

The resource adequacy concept has become increasingly critical as the global energy sector undergoes significant transformations driven by technological advancements, policy changes, and environmental concerns. Recent trends indicate a growing emphasis on renewable energy integration, advanced energy storage solutions, demand response initiatives, decentralized generation, and grid modernization.

A major trend both promoting the use of resource adequacy and reshaping resource adequacy modeling techniques is the rapid integration of renewable energy sources such as wind and solar. Countries worldwide are investing heavily in renewable energy to reduce greenhouse gas emissions and combat climate change. However, the intermittent nature of these sources presents challenges for maintaining a reliable power supply. Electrical planners now must think more carefully about how best to capture the electrical capacity contributions provided by each energy resource technology for resource adequacy calculations. Historically, electricity had been generated by dispatchable power plants burning fossil fuels that could be controlled by system operators. Now, however, an increasing share of electricity is produced by the intermittent availability of wind and sunlight.

This transition from conventional generation to the use of renewable resources thus necessitates robust grid management solutions to ensure a stable power supply during periods of low renewable generation. Consequently, utility planners and operators are confronted with the need to work more with probabilities and less with certainties when assessing electricity supply. To illustrate, one resource planning concept that has gained considerable attention in recent years, Effective Load Carrying Capacity (ELCC), restates the nameplate capacity of intermittent renewables into an average value that can be expected to be available for system operators rely upon during peak periods.

Turning from supply-related issues facing the electricity industry to demand-related issues, the DOE has noted that electricity demand, which remained relatively flat for a decade, is now exhibiting strong growth, driven primarily by data center construction, electric vehicle (EV) charging requirements, and building electrification. It will be challenging enough to expand electricity generation supplies adequately to meet these growing demands, but even more so if the large current fleet of power plants burning fossil fuels is simultaneously being retired to meet environmental objectives.

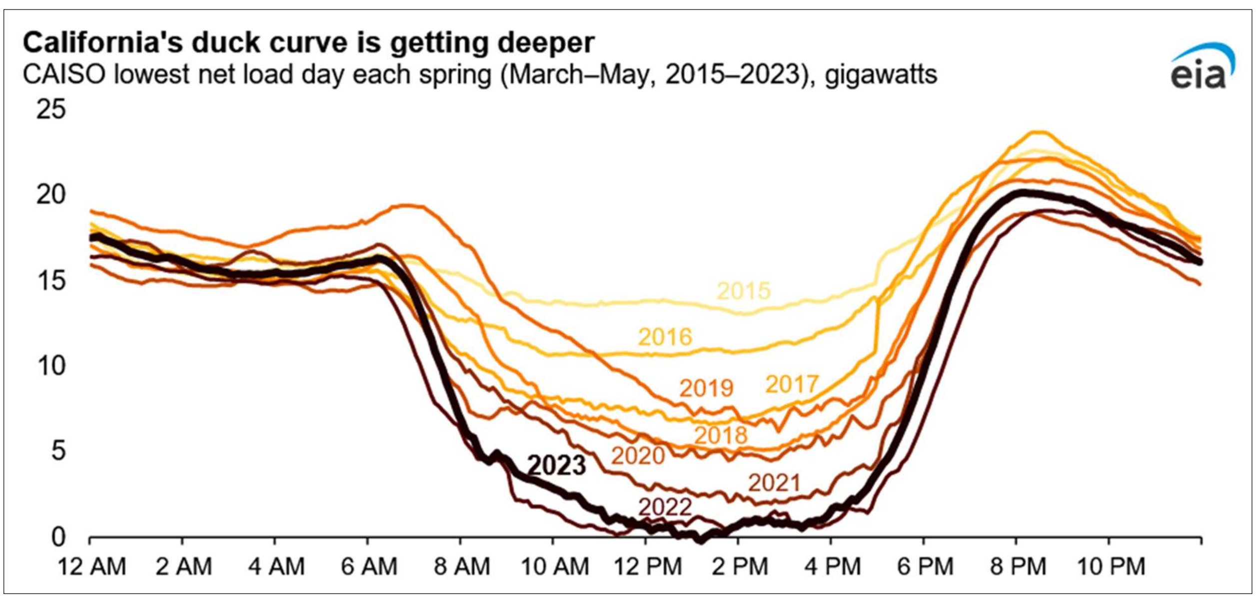
Demand response (DR) programs and energy efficiency measures are increasingly being adopted to enhance resource adequacy. These initiatives involve adjusting consumer demand through incentives, reducing strain on the grid during peak periods. In the United States, DR programs have become integral to grid management at many utilities, incentivizing consumers to reduce or shift their energy usage during peak times. The impact of these programs can be seen in reduced peak load, reduced capacity requirements at peak hours and more stable grid operations.

The increasing adoption of decentralized generation (DG) is transforming the traditional centralized utility model. These sources of electricity generation are typically located on customer premises and hence are often referred to as “behind-the-meter" (BTM). DG solutions are usually installed by (or on behalf of) customers to reduce electricity bills. By far, the most common form of DG is rooftop-mounted photovoltaic (PV) systems based on solar panels, as dramatic cost declines have made customer-sited electricity generation from PV cost-competitive with grid-supplied electricity. In most parts of the world, rooftop PV systems are being added at a rapid pace.

Electricity grid operators around the world are confronting a growing challenge imposed by the addition of large quantities of solar electricity generation, due to a phenomenon referred to as the “duck curve”. Historically, electricity system demand reached minimums during overnight hours, followed by gradual increases during the day to reach peak levels in the late afternoon and early evening. However, the injection of growing volumes of PV-based electricity generation is depressing the amount of electricity the grid must supply during mid-day hours. When plotted over the course of the day, the difference between gross electricity volumes demanded by customers and net electricity volumes to be satisfied by the grid produces a figure that resembles a duck – hence the term **“duck curve”, a concept that has quickly come to occupy a central place in the concerns of electric utility planners.**

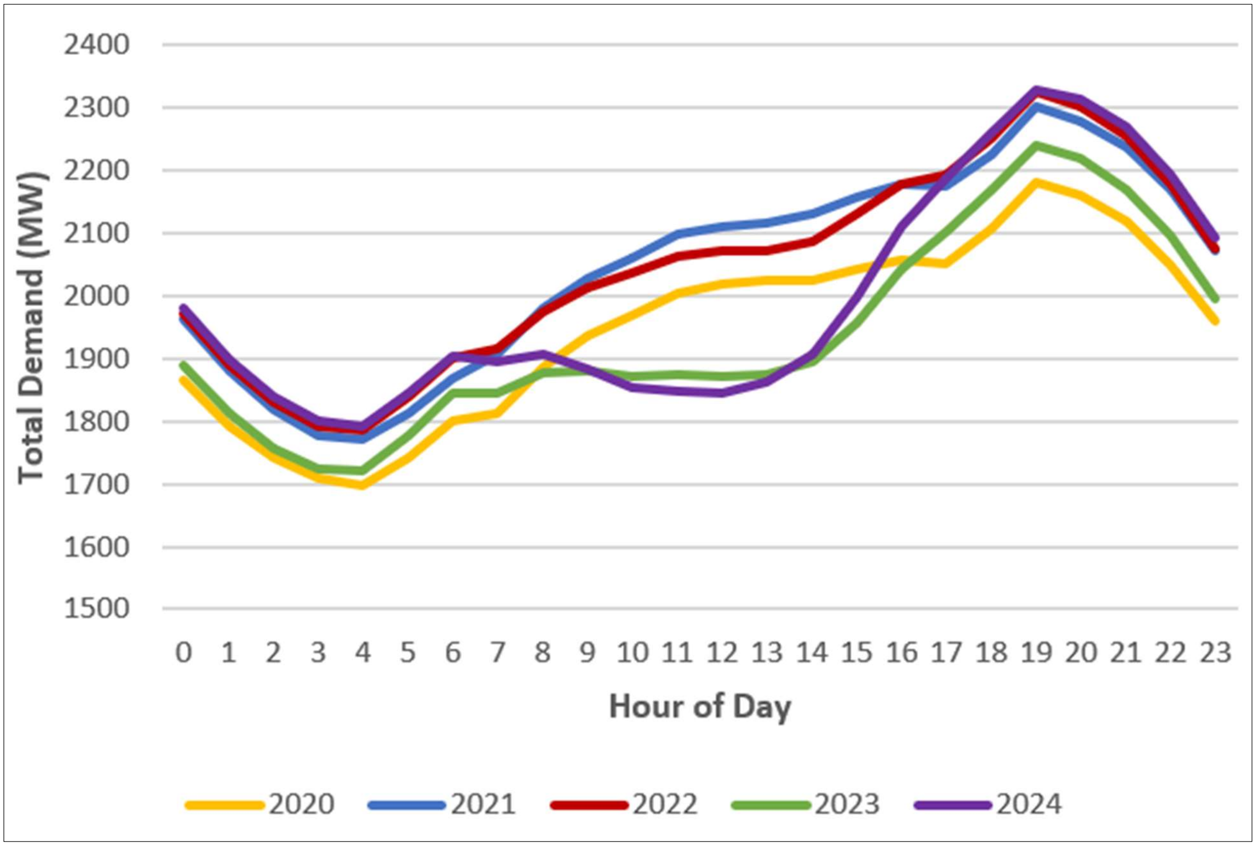
In some locations, the duck curve is getting so severe that net electricity volumes (i.e., system load) occasionally can become negative: more electricity is being produced by all PV sources than is being demanded by all customers on the grid. Figure 1-2 below illustrates the evolution of the duck curve in California, with increasing volumes of PV generation causing system load levels to approach zero during the middle of the day.

Figure 1-2: PV-Induced Duck Curve in California



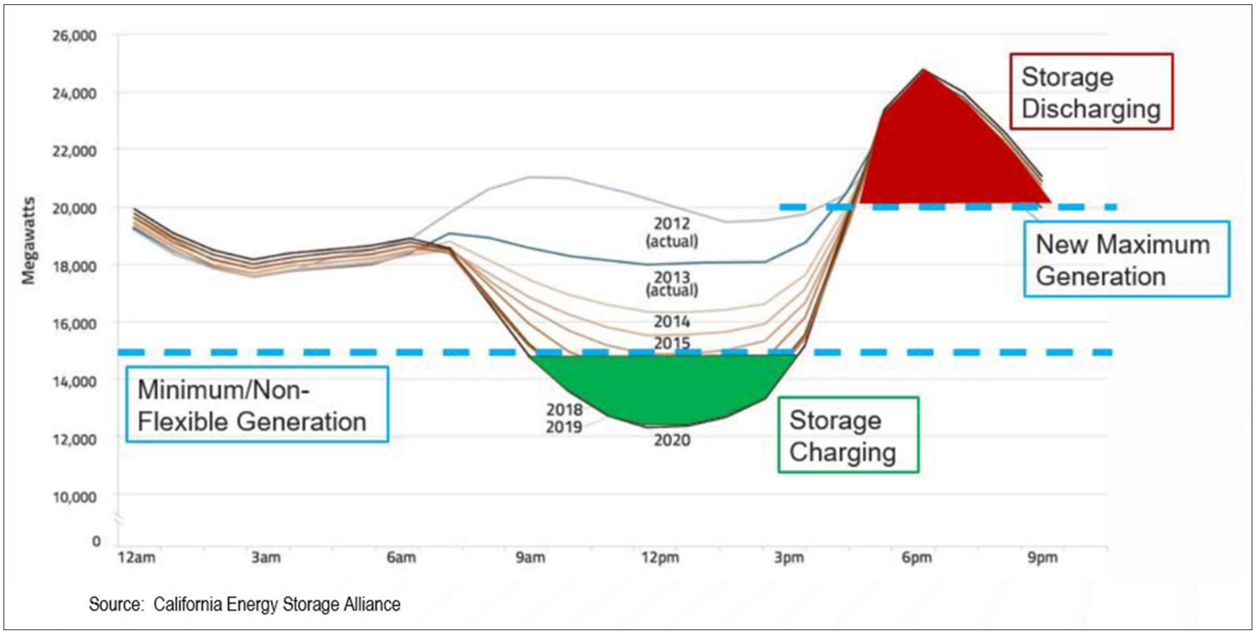
With increasing PV adoption since LUMA assumed operational responsibility for the electric grid in June 2021, the duck curve has begun to reveal itself in Puerto Rico, as shown below in Figure 1-3:

Figure 1-3: Emergence of Duck Curve in Puerto Rico, Hourly Electricity Demand During Average Day of First Quarter



As a result of the challenges to electric system operations posed by the duck curve, energy storage technologies have recently become an essential tool for system operators to maintain grid reliability in the face of growing volumes of intermittent renewable energy sources such as PV. As shown in Figure 1-4 using data from California as an illustrative example, by storing electricity generated by PV during mid-day periods of low system demand and releasing stored energy during peak demand as or after the sun sets, the addition of energy storage will significantly enhance resource adequacy in Puerto Rico, given that resource deficiencies are most common and severe during evening hours.

Figure 1-4: Energy Storage to Alleviate PV-Induced Duck Curve



In such a dynamic energy landscape, evolving regulatory frameworks and market structures are crucial for maintaining resource adequacy. For example, the DOE's Grid Solutions Program addresses the challenges posed by increasing interdependencies in energy systems, focusing on grid modernization and the development of new control and coordination solutions.

Over the past decade, to address these various concerns and their many implications, the electricity industry has significantly advanced the frontier of resource adequacy analysis. In March 2011, NERC released a guideline report, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning.* This report identified the need for alternative approaches rooted in probabilistic analysis when determining variable generation capacity contributions toward availability and resource adequacy. Further, the report recommended the comparison of adequacy study results based on alternative metrics rather than solely PRM.

In 2017, FERC approved NERC Reliability Standard BAL-502-RF-03[3], which created requirements for entities registered as regional planning coordinators to perform and document resource adequacy analyses. The standard recommends an average loss of load expectation (LOLE) of 0.10 days per year. This target is also known as the "one day in 10-years" criterion since it means that, on average, only 1 day in every ten years will experience a generation shortfall, resulting in the shedding of load.

Continuing this expanding resource adequacy guidance, NERC released the 2018 technical reference report, *Probabilistic Adequacy and Measures.* Due to the evolving generation supply mix landscape, this technical reference report focused on identifying, defining, and evaluating more probabilistic approaches and risk measures to provide insights into resource adequacy assessments. Depending upon the investigation being undertaken, appropriate resource evaluation planning approaches range from relatively simple calculations of PRMs to extensive generation resource adequacy simulations that

[3] North American Electric Reliability Corporation, Standard BAL-502-RF-03, October 2017.

calculate system loss of load probability (LOLP) values. The application of advanced technologies and data analytics is revolutionizing how utilities manage resource adequacy. Predictive analytics, artificial intelligence (AI), and machine learning algorithms enable more accurate forecasting of both electricity demand and generation supply patterns. Bridging between demand and supply, system operators are increasingly using AI to optimize grid operations. For instance, Google's DeepMind has collaborated with National Grid in the UK to develop AI algorithms that predict energy demand and manage supply more efficiently.

In summary, the pursuit of resource adequacy in the global electricity sector is driven by a combination of technological advancements, regulatory reforms, decarbonization policies, and evolving market dynamics. The integration of renewable energy, the adoption of advanced energy storage solutions, the rise of DR programs and DG collectively can contribute to a more reliable, resilient, and sustainable energy system – though a holistic approach to coherently manage these various factors is required. As the energy transition accelerates, utilities worldwide must navigate these trends to ensure that they can meet the growing electricity demands of the future while also maintaining resource adequacy and reducing emissions.

1.3 Resource Adequacy Assessment in Puerto Rico

The above discussion provides an overview of issues facing the electricity industry – and how these issues affect resource adequacy – worldwide. As emphasized many times in the above discussion, regional differences will emerge due to locally unique circumstances: weather, terrain, demographics, economy, politics, culture, and history. Accordingly, this section of the report discusses the distinct factors pertaining to resource adequacy assessment in Puerto Rico.

As is widely known, the Puerto Rico electricity system faces numerous challenges that many other utilities in the world do not face. Many of these challenges have root causes that predate Hurricane Maria in 2017, which in turn created many additional challenges. This report will not address this history. However, to provide an appropriate context for undertaking and interpreting a resource adequacy assessment, it is worthwhile to lay out the unique set of facts about the Puerto Rico electricity sector.

Although it does not affect the appropriate methodology for resource adequacy assessment, Puerto Rico's inherited electricity supply situation has a significant bearing on resource adequacy results. As will be described in detail in Section 2, Puerto Rico's resource adequacy deficits are largely because the installed generation base in Puerto Rico is uncommonly unreliable – due both to age and to prolonged periods of underinvestment. If all the generation facilities in Puerto Rico were as reliable as those found at most other U.S. utilities, Puerto Rico's resource adequacy would be significantly better than is currently the case. Unfortunately, making improvements to existing power plants cannot be accomplished without taking them offline for prolonged outages (thereby exacerbating resource inadequacy) and adding new capacity will not come quickly or without significant capital investment. In other words, Puerto Rico's resource adequacy deficiencies described in this report are not easily remedied. Expectations should be set accordingly.

The unreliability of the Puerto Rico generation fleet is exacerbated by the fact that the mix of assets in the Puerto Rico generation portfolio is dominated by power plant units that are large in relation to the overall electricity system. In Puerto Rico, there are four units that are over 400 MW nameplate capacity, and if any one of these units experiences a forced outage, the grid immediately loses approximately 10% of its operating capacity. From a portfolio risk perspective, this is a very significant amount of generation capacity to lose at once: in most of North America, the unexpected outage of a similarly sized power plant has minimal impact to the entire grid because such a loss represents less than one percent of total operating capacity. On the mainland, there is no power plant unit that represents anywhere close to 10% of regional demand, so that a forced outage at even the largest nuclear plant (approximately 1,300 MW) has much less impact on grid reliability than the loss of any baseload unit causes to the Puerto Rico electricity system.

Unlike many electricity systems around the world, Puerto Rico confronts the reality that it will be periodically hit by strong hurricanes and earthquakes that will be highly disruptive. No amount of weatherproofing can completely prevent prolonged outages of generating capacity and other grid infrastructure caused by such severe natural disasters. As shown by Hurricane Maria in 2017, power plant damages caused by a devastating hurricane can take many months to repair, as major components essential for power plant operation are not sitting on the shelf in inventory but instead must be built from scratch – often in manufacturing facilities far away from Puerto Rico, subsequently requiring shipping and on-site installation. Inevitably, this possibility affects the assessment of resource adequacy for Puerto Rico.

Putting aside severe storms, normal weather conditions found in Puerto Rico also affect resource adequacy in ways that are unusual relative to electricity systems in other locations. Notably, the intermittency issues associated with solar and wind energy – important on any electricity grid – are even more critical in Puerto Rico. From a resource adequacy perspective, the most important hours to consider are those in which system electricity demand is highest, usually because of air conditioning usage. Whereas the daily peak of electricity demand occurs in late afternoon for many utilities, peak demand in Puerto Rico occurs in the early evening.

The difference between electricity demand peaking in the late afternoon vs. early evening is important because solar production is essentially zero during peak demand hours in Puerto Rico, where the sun always sets before 7 pm. (At higher latitudes, summer sunsets occur in the mid-evening or even the late evening, meaning that PV will still be able to supply some energy during peak air conditioning hours.) Magnifying this, wind energy in Puerto Rico generally is more productive during daylight hours than during overnight hours, whereas wind energy production is higher overnight than during daytime in many other places. Together, this means that the additions of new renewable energy capacity in Puerto Rico will contribute an unusually small amount to resource adequacy during peak demand hours unless also augmented by energy storage.

The consistently hot weather year-round in Puerto Rico means that there is less opportunity to schedule maintenance-related outages on power generation units when they will not be needed to serve system load. While most U.S. utilities can schedule generator maintenance outages during spring and fall months when electricity demand levels are relatively low, owners and operators of generation facilities in Puerto Rico have much less flexibility and much shorter time windows when scheduling maintenance outages. Thus, when scheduled maintenance outages are taken, there is a higher probability that this will negatively affect resource adequacy and increase the likelihood of load-shed events.

An electricity system for any island separated from a large body of land by long distances (i.e., beyond the economic reach of underwater electricity transmission) usually must maintain a higher PRM than is the case for tightly interconnected regional electricity systems on a continent such as North America or Europe. On those continents, any one electric utility or any one regional electricity system can exchange power with neighbors on an as needed basis, and this diversity of potential supply sources mitigates the risk of resource inadequacy because of the ability to import power from elsewhere during times of need. An island like Puerto Rico does not have that luxury, and consequently a higher PRM will be required to achieve a comparable degree of resource adequacy as those achieved by larger continental utilities with lower PRMs. This resource adequacy report does not recommend a PRM for Puerto Rico to employ, although it may be beneficial for future resource adequacy reports to consider this possibility.

In addition to informing the IRP currently being undertaken by LUMA to recommend resource additions based on assessments of future trends in Puerto Rico's electricity demand and its legacy generation base, this resource adequacy report is intended to provide Puerto Rico stakeholders a deeper understanding of the fundamental issues underlying electricity system reliability on the island. As the discussion above indicates, many of these issues are specific to Puerto Rico, meaning that reliability measures from other electricity systems should be used in comparison to Puerto Rico only with care.

2.0 Current State of Puerto Rico's Electricity System

A resource adequacy analysis relies upon many assumptions about both the supply of and the demand for electricity on the region's electricity system. Therefore, performing a resource adequacy assessment for Puerto Rico requires a deep understanding of the island's electricity system. This section provides an overview of Puerto Rico's electricity system, with a deeper level of detail on data and assumptions provided in Appendix B.

2.1 Role of LUMA

The legal framework for the Puerto Rico electricity system established by Act 17-2019 and Act 57-2014 provides for the desegregation of the electricity sector formerly managed by the Puerto Rico Electric Power Authority (PREPA), including the division of operational responsibilities for generation from operational responsibilities for transmission and distribution activities. Accordingly, and per Act 120-2018, as amended by Act 17-2019, Genera PR is now responsible for the operation and maintenance of PREPA's generation facilities, whereas LUMA is responsible for operating the transmission and distribution assets owned by PREPA.

LUMA's responsibilities are undertaken under a long-term operating agreement administered as part of a public-private partnership overseen by the Puerto Rico Public-Private Partnerships Authority (P3A or P3 Authority) and subject to regulatory oversight by the Puerto Rico Energy Bureau (PREB or Energy Bureau). Under the Puerto Rico Transmission and Distribution Operation and Maintenance Agreement between the Puerto Rico Electric Power Authority (PREPA), the Public Private Partnerships Authority (P3 Authority), LUMA Energy, LLC and LUMA Energy ServCo (collectively, LUMA) effective June 21, 2020 (T&D OMA), LUMA carries out multiple activities to improve the reliability and resilience of the Puerto Rico electricity system.

Although LUMA does not own or operate capacity to generate electricity, associated with its responsibilities as system operator, LUMA carefully monitors and dispatches available generation resources – operated by Genera PR and other independent power producers (e.g., EcoElectrica, AES) – to meet customer demand and ensure the reliability of the overall electricity system of Puerto Rico. In addition, LUMA is responsible for planning and conducting studies to assess the resource adequacy of the electricity system to meet the energy demands of Puerto Rico.

One of LUMA's main activities in this vein is the development of an Integrated Resource Plan (IRP) for Puerto Rico. IRPs are commonly developed by electric utilities to anticipate future resource needs and recommend investments in projects and programs that will meet these needs in a manner that makes appropriate trade-offs between the lowest cost, lowest environmental impact, and greatest reliability/resilience of electricity service. IRPs are then subject to regulatory approval to authorize the implementation of any resource additions.

This resource adequacy report provides important inputs into the 2024 IRP currently being prepared by LUMA and to be submitted to and reviewed by the Energy Bureau in Case No. *NEPR-AP-2023-0004*, *In Re: Review of the Puerto Rico Electric Power Authority Integrated Resource Plan*. The report is also intended to support other proceedings and discussions overseen by the Energy Bureau intended to help reduce the risk of insufficient supply to meet energy demand in Puerto Rico.

LUMA is committed to working with the government, generators, and the Energy Bureau to address these systemic generation issues to provide the people of Puerto Rico with safe, reliable, and clean energy. While this report supports decision-making regarding generation retirements, additions, modifications, maintenance schedules, and other items to reduce the risk of insufficient electric supply, specific recommendations on generation capacity additions are the subject of the IRP process, which delivers a series of reports separate from this one. The IRP process will use data and information from this report to help inform recommendations, including determining which technologies are best suited to meet system needs most effectively.

2.2 Puerto Rico Electricity Supply

The size, number, availability, and generating characteristics of the supply resources in an electricity system are some of the most important inputs into resource adequacy analyses. Puerto Rico's electricity comes from three different sets of sources:

- **Thermal power plants:** power plants that burn fossil fuels to produce electricity for supply to the Puerto Rico grid
- **Renewable power plants:** power plants that supply electricity to the Puerto Rico grid without burning fossil fuels, such as solar, wind, landfill gas, and hydroelectric
- **"Behind-the-meter" (BTM) generators:** solar panels or other equipment located on customer premises for supplying electricity directly to customers.

The following subsections provide an overview of each of the above three sets of generation resources, including considerations for how they impact overall system resource adequacy analyses.

2.2.1 Thermal Power Plants

Thermal power plants have an aggregate available (or "net dependable") capacity of 4,257 MW, accounting for approximately 94% of the operating generating capacity supplying electricity to the Puerto Rico grid. Consequently, it is vital to have a good understanding of Puerto Rico's thermal power plant fleet as a foundation for resource adequacy assessment in Puerto Rico.

Thermal power plants burn fossil fuels: natural gas, fuel oil (sometimes called "bunker" fuel), diesel fuel, and coal. An essential characteristic of these plants is that they are "dispatchable", meaning they can be throttled up and down and turned off or on at the system operator's command by modulating fuel consumption.

Table 2-1 summarizes key parameters for the operating thermal power plant fleet in Puerto Rico. Two measures of capacity are presented: nameplate and available. Nameplate capacity represents the rated capacity of the power plant as of the date of initial operation, whereas available capacity represents the maximum capacity that the power plant can be depended upon to supply to the grid when called upon by the system operator. In addition, historical forced outage rates for each plant are also presented in Table 2-1. Forced outage rates are defined as the percentage of time in a typical year that the power plants are unavailable to generate electricity.

Table 2-1: Summary of Expected Operating Thermal Power Plants in FY2025

Generator Name	Start of Operations	Fuel	Nameplate Capacity (MW)	Available Capacity (MW)	Forced Outage Rate (%)
AES 1	2002	Coal	227	227	5
AES 2	2002	Coal	227	227	10
Aguirre Combined Cycle 1	1977	Diesel	296	100	50
Aguirre Combined Cycle 2	1977	Diesel	296	100	40
Aguirre Steam 1	1971	Bunker	450	300	25
Aguirre Steam 2[1]	1971	Bunker	450	350	15
Costa Sur 5	1972	Natural Gas / Bunker	410	250	20
Costa Sur 6	1973	Natural Gas / Bunker	410	350	15
EcoElectrica	1999	Natural Gas	545	545	2
Palo Seco 3	1968	Bunker	216	160	15
Palo Seco 4	1968	Bunker	216	160	60
San Juan 7	1965	Bunker	100	70	40
San Juan 9	1968	Bunker	100	90	8
San Juan Combined Cycle 5	2008	Natural Gas / Diesel	220	210	15
San Juan Combined Cycle 6	2008	Natural Gas / Diesel	220	210	15
Cambalache 2	1998	Diesel	82.5	75	10
Cambalache 3	1998	Diesel	82.5	75	10
Mayagüez 1	2009	Diesel	55	47.5	30
Mayagüez 2	2009	Diesel	55	47.5	30
Mayagüez 3	2009	Diesel	55	47.5	30
Mayagüez 4	2009	Diesel	55	47.5	30
3 Palo Seco Mobile Pack	2021	Diesel	3x27	81	9
7 Gas Turbines (Peakers)[2]	1972	Diesel	7x21	147	40
4 TM Gens (Palo Seco)	2023	Natural Gas / Diesel	2x20 + 2x25	90	3
10 TM Gens (San Juan)	2023	Natural Gas / Diesel	10x25	250	3
Total			**5,336**	**4,257**	**—**

Notes:

1. The Expected Case reflects the current system but considers Aguirre 2 to be out of service for the duration of the simulations. This generator is kept out of service to account for the planned maintenance schedule overruns that are very common to the main generators on the island. This is described further in Appendix B.
2. A total of 18 gas turbines, each with a capacity of 21 MW, are installed. Only 7 are considered operational, due to frequent outages at these units. From a resource adequacy perspective, there are several important points to note in Table 2-1. First, relatively little new thermal generation capacity (420 MW) has been installed since Hurricane Maria in 2017: the Palo Seco Mobile Pack (81 MW) in 2021, and the trailer-

mounted (TM) emergency generators (340 MW) secured from FEMA in the wake of Hurricane Fiona and deployed on Puerto Rico in 2023.

Conversely, many of the power plants in the Puerto Rico thermal power plant fleet were constructed 50 or more years ago, which is near or beyond the projected useful life of these facilities. Excluding the new additions described above and the thermal plants owned by independent power producers (AES and EcoElectrica), the remaining generation fleet has received suboptimal levels of investment over decades of operation. The harsh maritime environment in which these power plants have operated has also been a constant source of deterioration. As a result, available capacity today for many of these units is lower (and sometimes, far lower) than nameplate capacity ratings established decades ago. (This fact has led to some confusion because some published reports about generation capacity in Puerto Rico refer to nameplate capacity only, thus providing a misleadingly optimistic view of the amount of electricity generating supply that Puerto Rico can rely upon to meet system demands.)

The aged and dilapidated state of many of the thermal power plants also leads to more frequent breakdowns. Historically, the forced outage rates of many of the existing thermal power plants have been very high, with approximately 2,500 MW of Puerto Rico's installed generators having historic forced outage rates of 15% or more, and much higher for some units. For reference, the average equivalent forced outage rate for North American power plants over the past five years was 7.25%. The higher the forced outage rates, the higher the chance that the generation facility will be unavailable when needed to serve system load, thus resulting in a shortfall of generation capacity.

In addition to increasing a plant's forced outage rate, old age and poor maintenance also increase the average duration of a forced outage, which is another very important consideration for resource adequacy. As was the case with Costa Sur following the damage it sustained during the January 2020 earthquake, the repairs stemming from a forced outage can take many months. Note that non-standard replacement components may need to be custom manufactured from scratch to replace damaged equipment on Puerto Rico's aging power plants and then transported to Puerto Rico by ship for installation by the relatively small population of qualified labor on the island. For this resource adequacy analysis, the duration of a forced outage for each thermal plant was assumed to be 40 hours, which represents an average repair time.

Additionally, age and inadequate preventative maintenance drive the need to take more frequent and longer scheduled maintenance outages than typical for power plants of a similar type and vintage that had been properly maintained.

Environmental considerations may also impair the ability of Puerto Rico's thermal power plants to contribute to resource adequacy. The U.S. Environmental Protection Agency (EPA) regulates power plant emissions in Puerto Rico and requires thermal power plants to maintain emissions below federally mandated levels for certain combustion by-products (e.g., NOx, SO_2, particulates). Some of Puerto Rico's thermal power plants are unable to fully comply with EPA regulations, and as a result are either required to shut down or limit operation. For this analysis, units that are operable but operationally restricted are considered as available dispatchable capacity that can still contribute towards meeting system load, because these units still can operate for short periods under emergency exceptions to avoid loss of load.

Each of the thermal power plants listed in Table 2-1 is expected to be operational and available for FY2025 and hence is included in the resource adequacy modeling documented in this report.

2.2.2 Renewable Power Plants

In contrast to the 4,300 MW of available capacity at Puerto Rico's thermal power plants, there is approximately 400 MW of nameplate capacity from renewable power plants that are expected to be operational in Puerto Rico in FY2025. Of the installed base of renewable power plants, approximately 70% of nameplate capacity is from solar photovoltaics (PV) facilities, 29% from wind facilities, and 1% from landfill gas facilities. The renewable power plants are listed in Table 2-2 below.

Table 2-2: Summary of Operating Renewable Power Plants

Generator Name	Commercial Operation Date	Source	Nameplate Capacity (MW)
AES Illumina	2012	Sun	20
Fonroche Humacao	2016	Sun	40
Horizon Energy	2016	Sun	10
Yarotek (Oriana)	2016	Sun	45
San Fermin Solar	2015	Sun	20
Windmar (Cantera Martino)	2011	Sun	2.1
Windmar (Vista Alegre / Coto Laurel)	2016	Sun	10
Pattern (Santa Isabel)	2012	Wind	95
Fajardo Landfill Tech	2016	Methane Gas	2.4
Toa Baja Landfill Tech	2016	Methane Gas	2.4
Punta Lima	Mar 2024	Wind	26
Ciro 1	Dec 2024	Sun	140
Total			**412.9**

In addition to what is presented in Table 2-2, Puerto Rico also has a small fleet of hydroelectric power plants with a nameplate capacity of approximately 100 MW. Most of these units date back to the 1930s and 1940s, many are not operational, and the few that do operate experience high forced outage rates (50% or higher). After accounting for long-term outages and reductions in rated capacity due to damage, the effective capacity of these units is roughly 10 MW – an amount considered to be negligible. Accordingly, hydroelectric plants are not listed in Table 2-2 and hydroelectric capacity is not included in the resource adequacy analyses documented in this report.

Table 2-2 reports the nameplate capacity associated with each renewable power plant. However, solar and wind energy generation facilities are intermittent in their ability to supply energy, based on sunshine and wind conditions that prevail at the power plant site, which naturally vary. However, from a resource adequacy perspective, it is critical to determine the amount of hourly renewable generation that could reliably be considered as available to serve load – and this amount will always be lower than nameplate capacity.

Rarely are solar or wind power plants able to supply their nameplate generating capacity: for solar plants, only around noontime on clear blue-sky days; for wind plants, only when the wind is steadily blowing at or above 25 mph. Most of the time, solar and wind power plants can supply something less than nameplate capacity to the grid. During overnight hours, solar power plants produce nothing; when there is no wind, wind power plants produce nothing.

Therefore, each MW of nameplate capacity from a solar or wind power plant can contribute significantly less to an electricity system's resource adequacy than each MW of nameplate capacity from a thermal power plant. As discussed in Appendix A, the Effective Load Carrying Capacity (ELCC) of solar PV in Puerto Rico (assuming no accompanying energy storage) is estimated to be less than 2% of nameplate capacity. As a result, any increment of 100 MW of solar generation installed in Puerto Rico on average provides less than 2 MW of expected capacity to help serve Puerto Rico system electricity demand during peak hours.

The methodology used in these analyses to properly account for renewable energy generation availability shares similarities to the methodology employed by Hawaiian Electric Company (HECO), an electric utility with many similarities to the Puerto Rico electricity system (see Appendix C). For these analyses, actual historical generation data (between 2019 and 2023) from each of the operating renewable power plants listed in Table 2-2 was gathered to calculate the average production level for each hour of the day, which was used as the resource's capacity contribution for the resource adequacy calculations. (For two renewable generators for which 2019-2023 data do not exist, Punta Lima and Ciro One, the average production levels of the historical generation from the overall fleet of renewable generators in Puerto Rico were used to develop assumptions on annual average capacity contribution.) This methodology thus captures the contributions of renewable generators towards improving system resource adequacy from a statistical standpoint, accounting for their intermittency while being based on actual historical production levels.

Properly capturing the hourly capacity contributions from variable renewable generation sources is an important consideration for resource adequacy analyses, since their hourly contributions of supply are, by definition, uncertain. Overestimating the capacity contribution of variable generators can leave the system with capacity shortfalls in the event the variable generators are unable to generate as expected, while underestimating the capacity contribution of variable generators can make the electrical system appear less reliable than it truly is. The sensitivity analysis results presented in Section 3.3 illustrate that the use of more conservative hourly capacity contributions from the variable generators modestly increases system LOLE.

2.2.3 Behind the Meter Generation Resources

In addition to the thermal power plants and renewable power plants that supply electricity to the Puerto Rico electricity grid for delivery to customers, a growing quantity of generation capacity is being installed at customer premises and supplying electricity directly to customers. Virtually all of this behind-the-meter (BTM) generation is comprised of rooftop PV systems. As of May 2024, an estimated 870 MW of BTM generation has been installed across Puerto Rico, and the installed base has been growing by roughly 20 MW per month in recent years. Table 2-3 below shows the estimated amount of BTM generation that is installed across the different regions of Puerto Rico.

Table 2-3: Summary of BTM Generation by Distribution Region

Region	BTM Generation (MW)
Caguas	167
Bayamón	166
Ponce	126
Carolina	116
Mayagüez	93
San Juan	112
Arecibo	86
Total	**867**

Although a supply resource that produces electricity, BTM generation is considered in resource adequacy analysis as reductions in system demand.[4] This is because, from the perspective of the system operator, BTM generation is equivalent to "negative load": small-scale and distributed across the entire service territory, BTM generation does not produce large volumes of electricity being directly injected into the electricity transmission system, and thus is outside the control of the system operator.

Note that BTM generation supplies electricity directly to the host customer, without being carried across the electric grid. When BTM generation volumes are low, such as output from a rooftop PV system during a cloudy morning, the relatively small amount of electricity generated merely serves to reduce the amount of electricity that the customer purchases from the grid. Only when BTM generation volumes exceed the customer's electricity consumption does any electricity -- the surplus amount between BTM generation volumes and customer demand -- flow from the customer back to the local distribution network, thereby increasing supplies on the electricity grid. For these reasons, in this resource adequacy analysis as in most resource adequacy analyses conducted by other modelers of electric utility operations, BTM generation is accommodated by making a negative adjustment to expected customer demands rather than being modeled as a generation supply resource.

2.3 Puerto Rico Electricity Demand

Electricity demand, also referred to as load, is another important element in resource adequacy evaluations, as electricity generators connected to the grid must be able to always meet aggregate systemwide electricity demand.

As in any electricity system, Puerto Rico's system demand varies for each hour of each day, throughout the year. Since a resource adequacy assessment estimates the probability that electricity generation sources will be able to satisfy demand during each of the 8,760 hours in a year, an hourly load profile must be developed. The hourly Puerto Rico load profile incorporated into the resource adequacy calculations described in this report is based upon the actual hourly metered load values from calendar year 2023, adjusted to correct for hours when metered data was unavailable or reflected abnormal

[4] Note that based on NERC Standard BAL-502-RF-03, BTM resources should not counted as a contribution towards resource adequacy. It is recommended that future resource adequacy analyses of the island either consider a probabilistic methodology of accounting for a dependable MW level of these resources or conservatively ignore their contributions.

operating conditions, and to account for changes in expected electricity demand due to various factors, such as the addition of BTM generation, overall population/economic growth, and adoption of electric vehicles.

Figure 2-1 below plots the load profile used for each hour in the resource adequacy analysis for FY2025. Note the seasonality of the load profile, with summer and early fall months exhibiting higher load than other months. The reason for this is that the months of summer and the early fall are the hottest in Puerto Rico, and electricity consumption associated with air conditioning and other cooling systems is a major driver of total electricity demand.

Figure 2-1: Hourly Puerto Rico Load Profile in the FY2025 Base Case

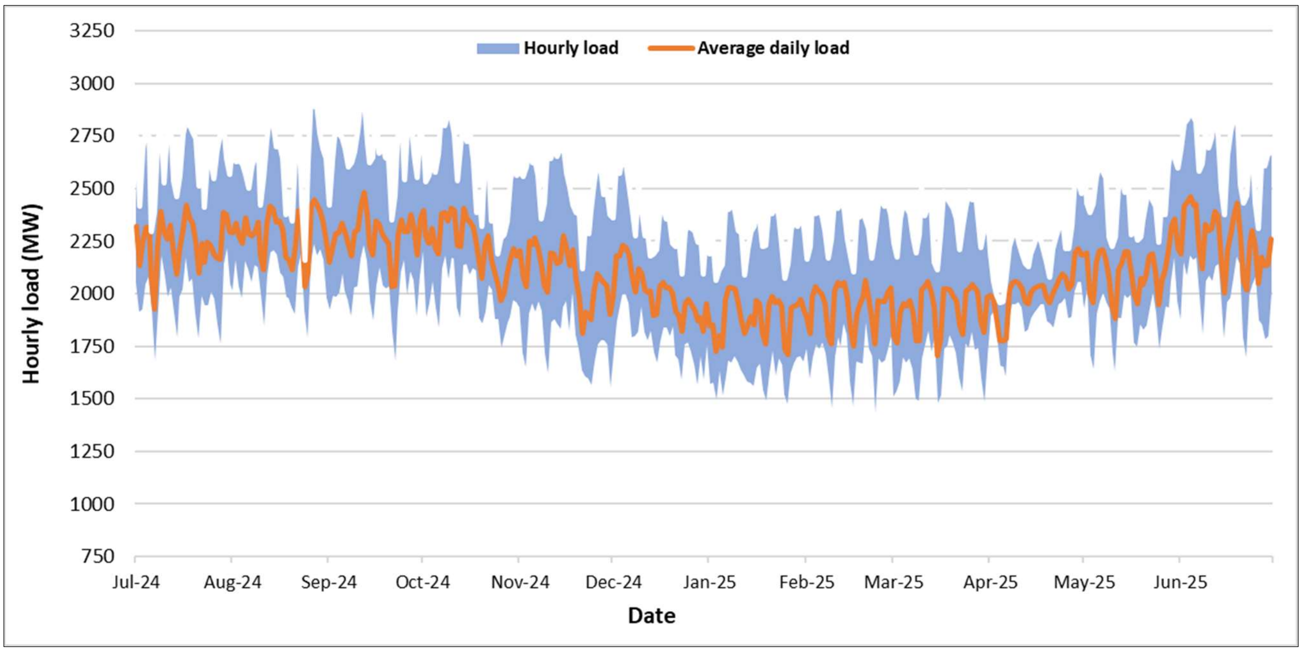
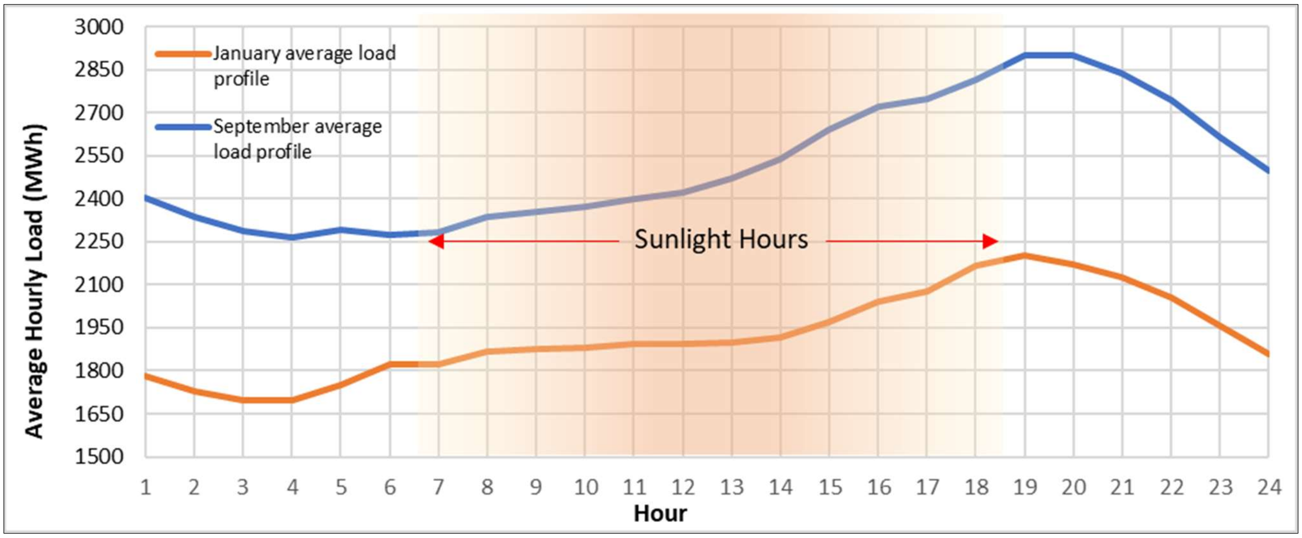


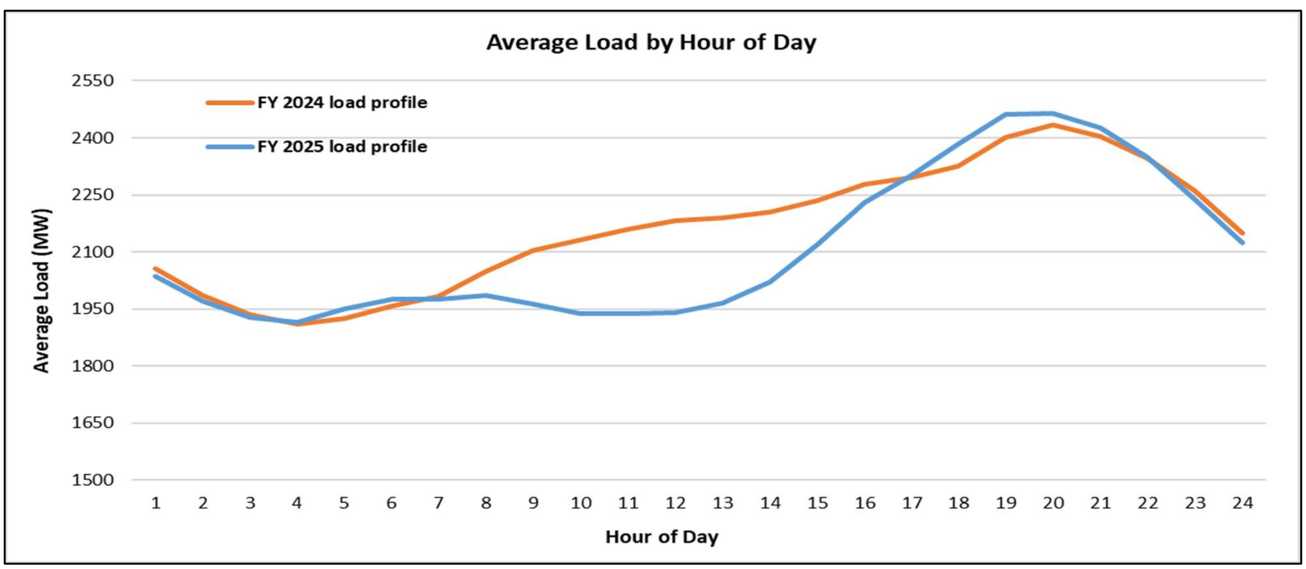
Figure 2-2 illustrates the hour-by-hour variance in Puerto Rico electricity demand by presenting hourly load profiles for the average day in September 2024 and January 2025 (the highest and lowest load months, respectively). As can be observed in the figure, load levels attain daily minimums during the overnight hours of the morning, and then steadily rise through the day, peaking in the early evening. The fact that the load profile peaks in the evening highlights a challenge that many other utilities with large amounts of solar generation are currently facing solar power plants do not generate electricity during the evening hours when electricity demands are high, since the sun has set. For solar power resources to contribute generation during the evening peak, they must be paired with energy storage. The size and duration of the storage systems are important considerations in determining the extent to which solar resources will contribute to resource adequacy during peak demand hours. An overview of energy storage in Puerto Rico is discussed further in Section 2.4.

Figure 2-2: Hourly Puerto Rico Load During Average Days in January and September FY2025



Demand assumptions for the Base Case reflect a forecast of changes in electricity demand patterns and levels since those experienced in 2023. Figure 2-3 compares the typical daily load profile for FY2024 to FY2025. As can be noticed, the duck curve phenomenon is already beginning to be observed in Puerto Rico: the FY2025 load profile used in these resource adequacy analyses exhibits a significant reduction of load during the daytime hours, due principally to the addition of rooftop PV systems (averaging about 20 MW per month). On the other hand, daily peak demands in the early evening hours are expected to increase slightly, reflecting growth in the Puerto Rico economy.

Figure 2-3: Comparison of Historical FY2024 Hourly Load Profile and Base Case Forecasted FY2025 Hourly Load Profile for Average Day



As is the case in the electricity industry worldwide, demand patterns in Puerto Rico will continue to change moving forward. On one hand, energy efficiency plans, demand reduction programs, the growth of BTM generation, the development of local microgrids, and other similar items will likely reduce overall system load; however, other items such as electric vehicle (EV) adoption have the potential to increase system load. The simultaneous growth in customer adoption of PV and EVs will thus likely drive down mid-day system load while driving up evening loads. Such a change in electricity demand patterns between hours of the same day highlights the potential role of energy storage as an asset class that can significantly improve the resource adequacy of the Puerto Rico electricity grid. For this reason, continued improvements in understanding customer electricity demand patterns, especially identification of the drivers and hours when system load is high, will be important for future resource adequacy considerations.

2.4 Puerto Rico Energy Storage Overview

Prior studies have shown Puerto Rico’s need for storage capacity: LUMA's 2023 resource adequacy study demonstrated how the addition of 220 MW of 4-hour duration standalone battery energy storage systems (BESS) reduced LOLE by 59%, Energy storage capacity is needed in Puerto Rico to enable increased renewable energy integration, since the current thermal power plant fleet will not be able to increase or decrease power output quickly enough to accommodate larger swings in energy produced by growing volumes of intermittent solar generation. In contrast, energy storage can alleviate this issue.

Under its IRP mandates, the Energy Bureau established a goal to maximize the rate of solar photovoltaic installations and battery storage in Puerto Rico. With that purpose, the Energy Bureau ordered PREPA “to issue a series of RFPs for provision of renewable energy in support of [the renewable portfolio standard goals of Act 82-2011, as amended], and for the provision of battery energy storage in support of capacity requirements needed to meet PREPA’s peak load requirements and in support of integration requirements for renewable energy generation”. Reflecting this, the IRP requires at least 1,360 MW of battery energy storage systems (BESS) by 2025, “and possibly higher levels if economic and available”, up to 1,720 MW if there are no administrative or logistical constraints on BESS installation.

Currently, no utility-scale energy storage projects are operational in Puerto Rico. To date, there have been various regulatory, planning and procurement challenges that have impeded BESS deployment in Puerto Rico. While certain retail customers have installed BTM energy storage systems to improve the resiliency of their electricity supply, accurate data on this activity is lacking, although it is understood that the total magnitude of installed BTM storage capacity is substantially less than 50 MW. Considering this amount to be negligible, no energy storage is included in the Base Case resource adequacy assessment.

However, several BESS initiatives currently underway could bring meaningful storage resources to Puerto Rico in the coming years. Some of the energy storage initiatives underway include:

- **Ongoing RFP Tranches:** The current procurement efforts underway in Puerto Rico for new renewable energy projects intends to also add 1,360 MW of BESS over multiple tranches, with 350 MW approved under Tranche 1 with another 140 MW under review.

- **Accelerated Storage Addition Program (ASAP):** The recently approved ASAP framework proposed by LUMA intends to add up to 360 MW of BESS at existing Independent Power Producer (IPP) locations with a pre-existing PPOA, aiming for initial deployment by the end of 2025. The use of existing interconnections and power plant sites should help accelerate BESS implementation.

- **Genera BESS:** Also taking advantage of existing power plant sites and interconnections to the transmission grid, Genera is developing a program to add up to 430 MW of storage at the existing generation facilities it operates on behalf of PREPA.

- **BESS at LUMA Substations:** LUMA is developing a project to add 4 x 25 MW BESS at several substations across the island to benefit the reliability and stability of grid operations.

- **Vieques and Culebra:** Various BESS initiatives are being considered to improve the resiliency and sustainability of electricity supply on Vieques and Culebra, including up to 11 MW BESS.

- **Battery Emergency Demand Response (DR) Program:** This pilot DR program launched by LUMA in late 2023 allows residential electricity customers with already-installed BTM energy storage systems to earn payments for allowing the system operator to dispatch their stored energy to provide emergency grid support.

Reflecting the above opportunities for the near-term addition of significant quantities of energy storage in Puerto Rico, several of the sensitivity analyses conducted in this resource adequacy assessment incorporate varying levels of energy storage resources, to evaluate the incremental implications of adding storage on improving the reliability of the Puerto Rico electricity system.

2.5 Puerto Rico Capacity Reserves

Generation capacity reserves are capacity resources not currently serving system load but could be quickly used to serve system load if necessary to respond to system condition changes, such as the unexpected loss of a power plant or transmission line. This section of the report discusses how generation reserves are managed in Puerto Rico to operate the electricity system.

Generation capacity reserves are categorized into Operating and Contingent reserves. The time required to supply power online is the main distinction between these two categories of reserves: Operating Reserves are available to supply online generation within 10 minutes or less, while Contingent Reserves supply online generation from 10 minutes up to 30 minutes.

Operating Reserves are actively managed and maintained by the system operator to address very short-term fluctuations in electricity supply and demand. Within the designation Operating Reserves, there are two categories of reserves within which power plants are running even though they are not serving system load: Spinning Reserves and Controlled Reserves.

- **Spinning Reserves** are generators that are already synchronized with the grid and can immediately increase their output to meet sudden changes in demand or compensate for unexpected generator or transmission line outages.

- **Controlled Reserves** are used to balance the supply and demand of electricity in real-time and maintain the stability of the grid. This is accomplished by using Automatic Generator Control (AGC) to modulate power plant capacity on a moment-by-moment basis to ensure that system voltage and system frequency stay within operational tolerances.

Based on the above, the amount of generating capacity required to be online at any instant equals the sum of (1) system load at that moment plus (2) Controlled Reserves plus (3) Spinning Reserves. The sum of Controlled Reserves plus Spinning Reserves therefore represents the capacity reserves that can instantaneously be tapped as needed to maintain reliable grid operations.

System operations policies in place for Puerto Rico state that the Controlled Reserves should be set to 300 MW and the Spinning Reserves should be set equivalent to the net dependable capacity of the largest PREPA-legacy generation unit being dispatched at the time. Given that the largest PREPA-legacy plant online is often on the order of 250-350 MW – note that Aguirre 1, Aguirre 2, Costa Sur 5 and Costa Sur 6 all have net dependable capacity ratings in that range – it is useful for the purposes of simplicity to consider the required capacity reserve margin to be 650 MW (= 300 MW Controlled Reserves + 350 MW Spinning Reserves). This level of capacity reserves has been deemed by the system operator to be essential for maintaining grid stability and reliability, to ensure that there is always enough surplus generation capacity online to be able to respond to sudden changes in system conditions without triggering interruptions in electricity service.

The preceding discussion is provided as background to illuminate the importance of adequate capacity reserves above and beyond the level of systemwide electricity demand in ensuring the reliability of electricity service under virtually any conceivable condition that might arise during any of the 8,760 hours of a given year. With this background, it is possible to begin considering the appropriate level of capacity reserves to achieve resource adequacy.

A comparison of the forecasted electric demand in Puerto Rico, which peaks at approximately 3,000 MW, to the total net dependable generation capacity of the Puerto Rico electric system, which averages nearly 4,500 MW, indicates that the Planning Reserve Margin (PRM) -- the ratio of available capacity to peak load -- for Puerto Rico is approximately 50%. In general, Puerto Rico's PRM is in line with, or even higher than, those found on other similarly sized islands. For example, in Hawaii, HECO reported that PRM was approximately 30% for Oahu (where the reliability of electricity service is generally considered satisfactory) in 2023.[5]

Given this, one might conclude that resource adequacy is not a significant challenge in Puerto Rico. This is not the case. Comparing PRM values from one location to another ignores location-specific variables that can have a significant impact on the ability for a utility to serve load in the location. For example, in Hawaii, forced outage rates are significantly lower than in Puerto Rico, meaning that generators in Hawaii can operate much more reliably with fewer generator outages than those in Puerto Rico, thus leading to many fewer instances of reserve capacity deficiency, resource inadequacy, and load-shedding. NERC notes this fact in *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning.*

> Unless the Planning Reserve Margin is derived from a LOLP (loss of load probability) study, there is no way to know what level of system risk is present. This is because some generators have higher forced outage rates than others. Therefore, one system with a 15 percent Planning Reserve Margin may not be as reliable as another system even though it also has a 15 percent Planning Reserve Margin.

[5] Hawaiian Electric Company Inc., Adequacy of Supply, 30 January 2024.

As a result, given the high outage rates and derates of the existing power plants in Puerto Rico, a simple comparison of the PRM in Puerto Rico to the PRM values in other similar locations masks the significant challenges Puerto Rico faces daily concerning generation resource adequacy. It is correct that there is a substantial amount of generation installed in Puerto Rico, with nameplate capacity significantly above peak demand levels; however, most of that generation is unreliable and too frequently incapable of operating when electricity is needed.

2.6 Load Shed Events in Puerto Rico

Service interruptions to electricity customers can be grouped into two broad categories: outages and load-shedding. Outages occur when there is a failure in the transmission and/or distribution grid delivering electricity to customers, and failures of this type may result from a wide variety of natural (e.g., storms), human (e.g., traffic accidents), or technical (e.g., equipment failure) causes. In contrast, load-shedding occurs when electricity generation supplies fail to meet system demand. Resource adequacy is relevant only to the latter category of service interruptions (load-shedding); consequently, **this report only addresses load-shedding implications associated with resource (i.e., generation supply) inadequacy and does not discuss potential losses of electricity service due to outages stemming from faults on the delivery network**.

Load shedding consists of a controlled and deliberate reduction of electricity demand during periods of strain or imbalance, to balance demand with the amount of generation supply that is available. During load shedding, sets of customers are intentionally disconnected from the power grid. While there are several different types of load-shed events, the two types generally experienced in Puerto Rico are Manual Load Shed (MLS) events and Underfrequency Load Shed (UFLS) events.

Manual load-shedding is used by electric utility companies to intentionally reduce the demand on the power grid when demand otherwise exceeds available electricity supplies by temporarily turning off electricity supply to specific geographic areas. MLS events rely on pre-defined plans that outline which areas to disconnect first. These plans prioritize critical infrastructure like hospitals and police stations, aiming to minimize disruption to essential services. Disconnections typically happen in a rotating fashion, with specific zones experiencing power outages for a predetermined duration before another area takes its turn experiencing an interruption in service. This approach helps distribute the inconvenience and ensure fairness of treatment between customers. The implementation of manual load shedding involves human operators in the system control room, who monitor grid conditions and, when necessary, remotely trigger switches to disconnect designated areas according to the pre-defined plan and standard operating procedures that state how to perform load shedding. In LUMA's case, System Operations Principle (SOP) Procedure #17 addresses MLS practices in Puerto Rico.

In contrast to MLS, underfrequency load shedding (UFLS) is a specific type of load shedding used by electric utility companies to maintain the stability and reliability of the power grid when there is a sudden and significant imbalance between electricity supply and demand. This imbalance can cause the frequency of the electrical system to drop outside of its normal operating range (59.8 Hz – 60.2 Hz), which can lead to widespread outages and major damage to electricity grid equipment if not corrected quickly. If the frequency drops to or below a predetermined threshold (59.2 Hz), UFLS protocols automatically (i.e., without the involvement of human operators in the system control room) disconnect a certain number of customers in aiming to restore system frequency to normal operating levels before conditions worsen and cause cascading failures leading to island-wide blackouts. If the frequency drops further, UFLS protocols automatically shed additional load in stages, disconnecting non-critical zones one by one. This prioritization ensures that essential services are the very last to be interrupted during a crisis.

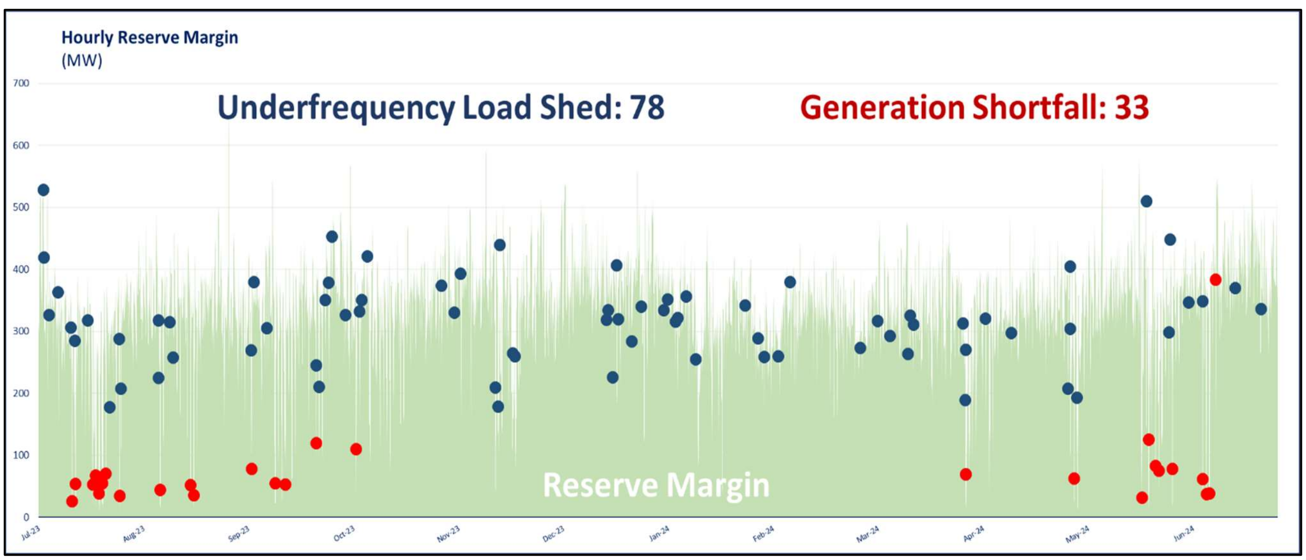
The most common cause of UFLS is a “unit trip”: the unexpected loss of a generation unit in the system. These unit trips are relatively commonplace in Puerto Rico due to the old thermal power generation fleet and the underinvestment in preventative maintenance thermal power plants have received. Table 2-4 below shows the incidence of all load-shed events experienced in Puerto Rico during FY2024. Of the 111 load-shed events in FY2024, 30% (N=33) were due to MLS. The occurrence of 33 MLS events during FY2024 implies an average monthly rate of 2.75 MLS events per month over the year.

Table 2-4: Summary of Puerto Rico Load-Shed Events in FY2024

Type of Load Shed	# of Events	Average Load Shed Magnitude (MW)	Average Duration (minutes)	Average Customers Affected
Manual Load Shed (MLS)	33	70	142	78,523
Underfrequency Load Shed (UFLS)	78	181	16	91,764
Total (UFLS + MLS)	111	148	54	87,682

However, as shown below in Figure 2-4, most of the FY2024 MLS events occurred during summer months, with no MLS events occurring during the winter months. Moreover, the MLS events tended to occur at peak hours (between 6:00 p.m. and 10:00 p.m.) during summer months when system demand was at high levels and could not be served with availability capacity, thus leading to generation shortfalls. Figure 2-4 also indicates that most MLS events happen when hourly reserve margins are exceptionally low (e.g., less than 150 MW). On average, each MLS event lasted slightly more than 2 hours with a magnitude of 70 MW.

Figure 2-4: Generation Shortfall Load-Shed Events Occur When Reserves Are Low



On the other hand, as also indicated above in Table 2-4, 70% (N=78) of the load shed events in FY2024 were due to UFLS events. Most of these UFLS events were caused by trips (i.e., unexpected outages) of a baseload unit or multiple units, creating a sudden and significant imbalance in generation supply and customer demand. On average, these events lasted 16 minutes with a magnitude of 181 MW. As summarized in Table 2-4, UFLS events triggered by unit trips were therefore more common but were much shorter in duration than the MLS events triggered by generation shortfalls.

As described above, insufficient capacity to meet demand (i.e., LOLE) triggers an MLS load-shed event. However, UFLS load-shed events are not triggered by insufficient capacity but rather by a momentary perturbation to the stability of frequency on the bulk power system. Therefore, the LOLE produced by resource adequacy analysis is a predictor of the number of MLS events that can be anticipated in a future year, but LOLE is not a predictor of UFLS events. Mathematically, 33 MLS events during FY2024 in Puerto Rico equates to a LOLE of 33 during FY2024 with probability of 100% (i.e., LOLE for FY2024 is known with certainty).

Put another way, since approximately 2 to 3 UFLS events occur per MLS based on historical data since 2023, most of the load-shed events experienced in Puerto Rico are <u>not</u> due exclusively to resource inadequacy. If generator reliability was significantly improved, it would benefit resource adequacy and hence would reduce MLS events in Puerto Rico. Increased generator reliability would also reduce UFLS events that strictly speaking do not result from resource inadequacy but do negatively affect electricity grid performance.

3.0 Resource Adequacy Analysis Results and Implications

Resource adequacy analyses of the Puerto Rico electric system were performed using the Probabilistic Resource Adequacy Suite (PRAS), a set of simulation tools developed by the U.S. National Renewable Energy Laboratory (NREL) as adapted for the Puerto Rico electrical system. A thorough validation of the PRAS model was documented in Appendix 7 of LUMA's *FY2023 Puerto Rico Electrical System Resource Adequacy Analysis* report. (See Appendix C herein for a more detailed explanation of resource adequacy methodologies.)

PRAS was used to quantify the resource adequacy of Puerto Rico's existing electricity system to establish a baseline set of resource adequacy measures. This allows for comparison to the performance of electricity systems in other regions. The results will help guide electricity system planning decisions in Puerto Rico. Using PRAS, electricity system supply and demand for FY2025 were simulated on an hourly basis to calculate the sufficiency of generation capacity to meet system load for each hour of the year. Since power plant forced outages occur randomly, a Monte Carlo analysis was conducted in which each of the 8,760 hours of FY2025 is re-simulated 2,000 times, with each simulation representing a "random draw" of available generating supply for that hour based upon each power plant's probability of being operationally available. By simulating available generation supply 2,000 times for each hour of the year, the fraction of each set of 2,000 simulations in which generation supply was adequate or inadequate enables a probabilistic summary of resource adequacy in that hour, which is then replicated for all 8,760 hours to produce a probabilistic summary of resource adequacy over the full course of the year.

In this section, Base Case resource adequacy results for the Puerto Rico electricity system are discussed in depth, followed by a discussion of the implications to resource adequacy if a major hurricane were to strike Puerto Rico during FY2025. Then, a review is presented of multiple sensitivity analyses that indicate potential changes to resource adequacy if certain aspects of electricity supply or demand were to be altered from Base Case assumptions. Finally, this section closes with a discussion of what resource additions would lead Puerto Rico to achieve the degree of resource adequacy that most U.S. electric utilities plan to attain. Detailed descriptions and results of all resource adequacy analyses are presented in Appendix A.

3.1 Base Case Resource Adequacy Results

The Base Case analysis reflects an assessment of generation resource adequacy that can reasonably be expected from the Puerto Rico electricity grid during FY2025. It reflects assumptions about both electricity demand levels anticipated to be experienced on the Puerto Rico system and the amount of generation available for system operators to serve electricity demand.

As discussed in Section 2.3, demand assumptions for the Base Case reflect hourly demand levels actually experienced in 2023, adjusted for (1) abnormal weather conditions during 2023 that unusually affected electricity demand, and (2) changes in electricity demand patterns and levels since those experienced in 2023.

Meanwhile, supply assumptions for the Base Case reflect generation capacity that is already installed. To be conservative and consistent with assumptions in prior resource adequacy reports, it was assumed that one of the two largest legacy thermal plants (Aguirre 2, 350 MW) would be unavailable for the study period. Supply assumptions do not include any planned generation additions and retirements occurring beyond 2024. Furthermore, no energy storage resources are assumed in the Base Case.

Consistent with the findings from previous resource adequacy reports prepared by LUMA, the Base Case indicates that Puerto Rico's resources are inadequate to meet industry standard levels of resource adequacy. Because Puerto Rico is unable to rely on electricity imports to support grid stability, and because the island's generators are unreliable, Puerto Rico faces significant challenges in meeting industry standard resource adequacy targets. The probability that Puerto Rico's generators would be unable to meet system load throughout the year at least once was calculated to be 100%. In other words, Puerto Rico can be certain that there will be at least one generation shortfall and at least one corresponding load-shed event during FY2025. As discussed further below, Puerto Rico can be confident that there will be dozens of days in which generation shortfalls and load-shedding will occur due to resource inadequacy.

Using Base Case assumptions, Table 3-1 summarizes the two key measures estimated from resource adequacy analysis, loss of load expectation (LOLE) and loss of load hours (LOLH). In addition to estimated averages, the width of the standard deviation and the minima and maxima for each of these two measures is presented.

Table 3-1: Summary of LOLE and LOLH Statistics for Base Case

Measure	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Average	36.2 Days / Year	154.2 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—
Distribution Standard Deviation	6.3 Days / Year	35.6 Hours/ Year
Distribution Maximum	58 Days / Year	310 Hours / Year
Distribution Minimum	16 Days / Year	57 Hours / Year

As expected for Puerto Rico's modest-sized islanded electricity system, the Base Case analysis demonstrates that outages to individual generators have a significant impact on the electrical system's ability to reliably meet load. For comparison, a large U.S. mainland utility or planning region with hundreds of generators is better able to manage outages to individual generators, simply because there are many other available generators that can make up for any losses of generation.

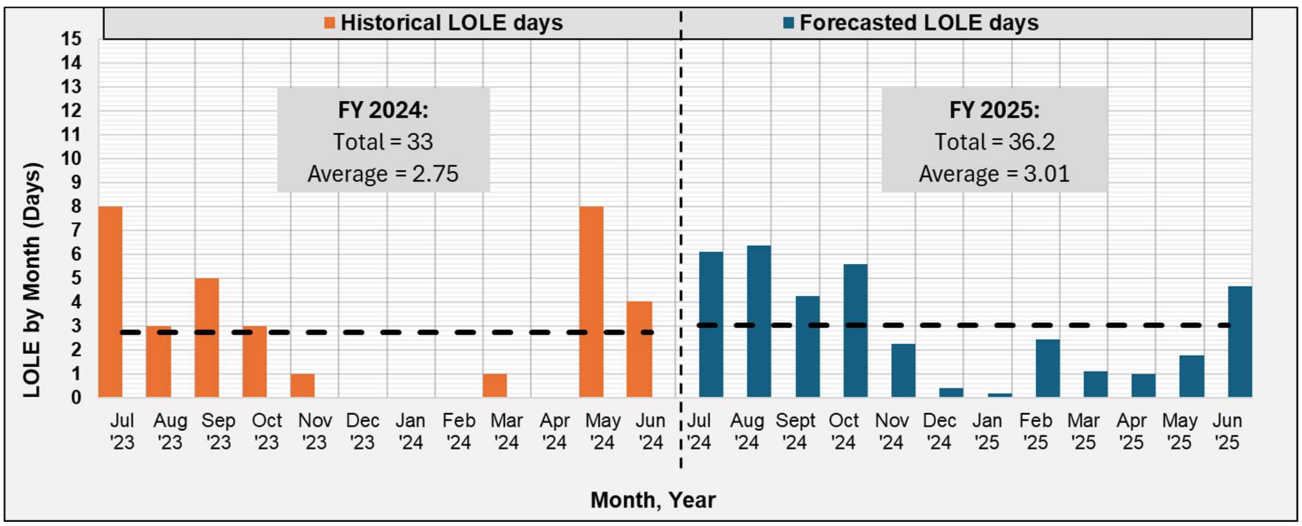
3.1.1 Loss of Load Expectation

Loss of load expectation (LOLE) is a measure of how frequently it can be expected that generation resources will be inadequate to serve system load.

Puerto Rico's Base Case estimated LOLE for FY2025 was 36.2 days/year. This indicates that, on average, one can expect a generation shortfall (i.e., "loss of load") to occur on 36.2 separate days during FY2025. For reference, Puerto Rico's estimated Base Case LOLE is 362 times higher than the commonly accepted 0.10 days per year LOLE industry standard. Even so, an estimated LOLE of 36.2 days represents an improvement in resource adequacy relative to an estimated LOLE of 50 days from a similar analysis conducted in late 2022. This improvement is due to 340 MW of TM generation added after Hurricane Fiona, which has meaningfully reduced the risk of insufficient generation,

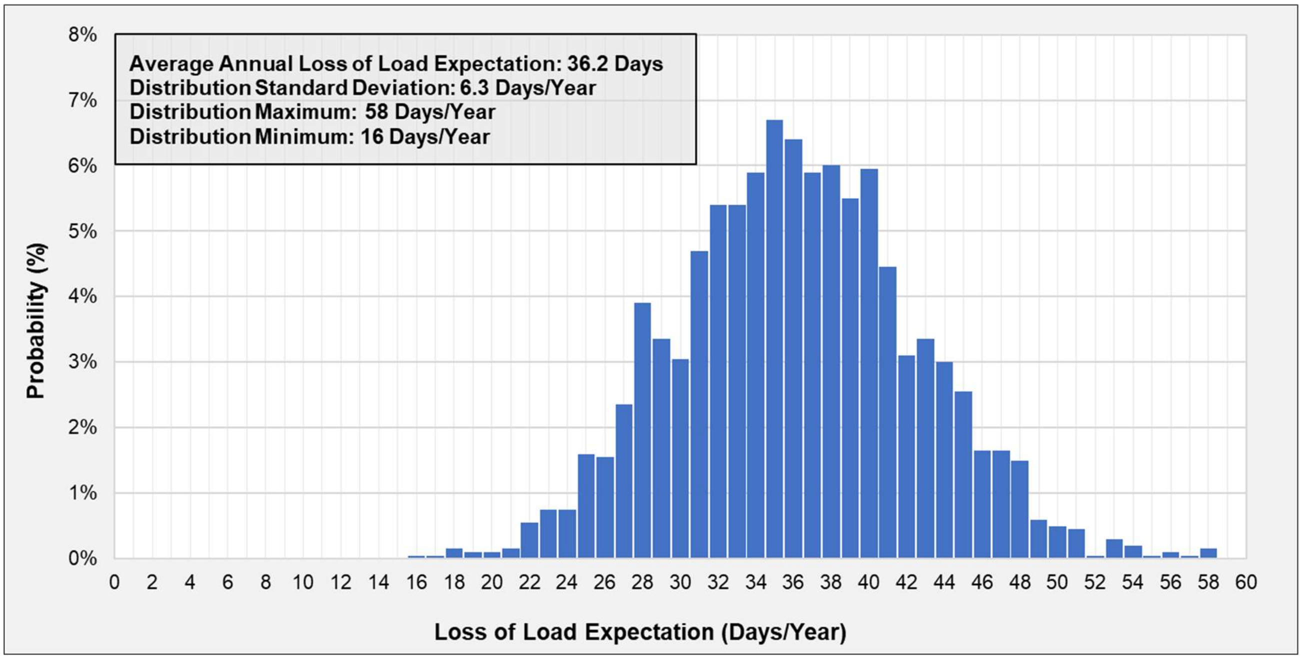
Figure 3-1 shows that LOLE of 36.2 days/year implies an expectation of 36 MLS generation-shortfall events per year – very consistent with the 33 MLS events actually experienced in FY2024. When averaged over the 12 months of a year, LOLE of 36.2 days per year equates to just over 3 days/month in which a load-shed event would be expected to occur.

Figure 3-1: Comparison of Historical FY 2024 LOLE versus Base Case Forecasted FY 2025 LOLE



An estimated 36.2 days of loss of load is a measure of the average or expected outcome for FY2025. An equally important item to note is the high standard deviation in the LOLE results. Among all the thousands of simulations conducted, in no instance was the estimated LOLE less than 16 days per year. On the other hand, up to 58 days per year of load-shed events were found to be possible. Figure 3-2below summarizes the distribution of estimated LOLE results of the Monte Carlo simulations for FY2025.

Figure 3-2: Base Case Loss of Load Expectation Probability Distribution



Several inherent and inherited characteristics of the Puerto Rico electricity system help explain the high average and wide distribution in estimated LOLE outcomes:

- Existing thermal power plants represent 94% of installed generating capacity in Puerto Rico, and their forced outage rates are very high relative to electricity industry norms. As a result, not only do power plants break down frequently, but multiple power plants often are unavailable at the same time. With power plant outages, there is a significant risk that there will not be enough remaining generation capacity available to serve system load.

- In addition, due to being past their useful life and in poor condition, thermal power plants in Puerto Rico often require prolonged planned maintenance outages, thus reducing the number of hours in a year during which they can be operated.

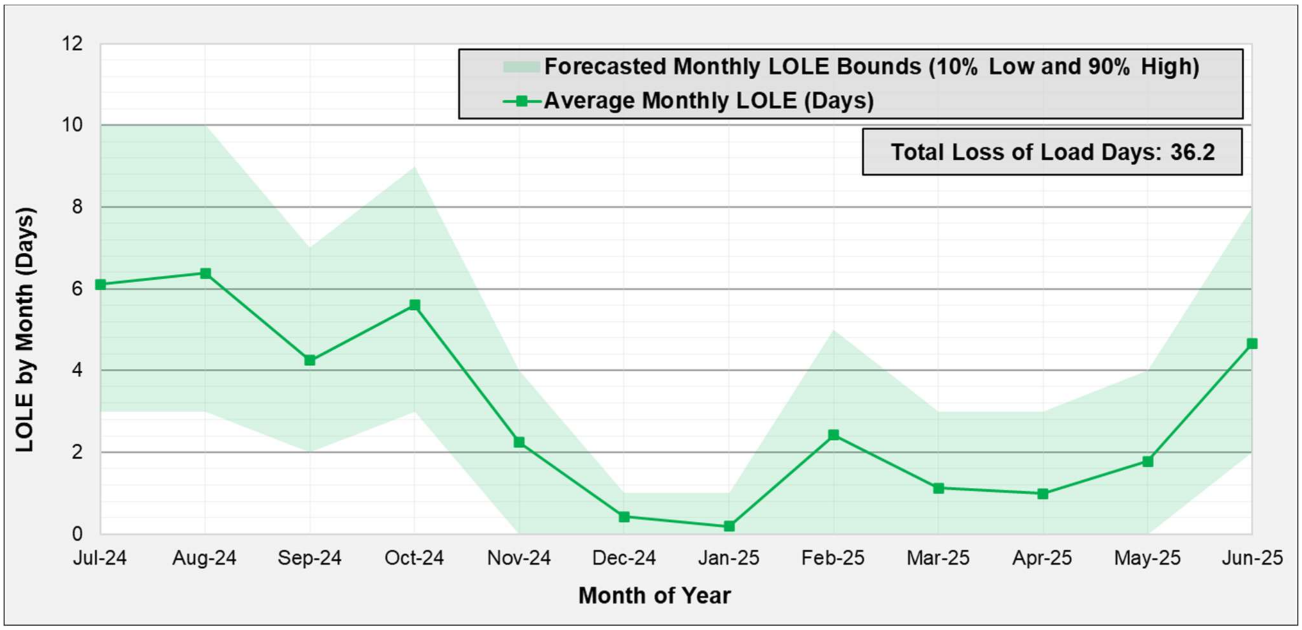
- When a power plant goes offline, the system operator must increase output from the power plants that remain online to meet system load. This places additional stresses on those power plants, resulting in a higher incidence of forced outages or longer downtime for them when undertaking planned maintenance later.

- Puerto Rico is unable to import electricity from neighbors and the system operator has control over only a few dozen power plants to generate electricity. By comparison, due to being electrically interconnected with each other, utilities on the U.S. mainland have access to hundreds of power plants that can be started or ramped up to meet load.

- In Puerto Rico, the sudden loss of a single large power plant that is online -- such as the Aguirre Steam units or the Costa Sur units, all of which are in the 250-350 MW capacity range -- immediately reduces the total available generating capacity on the system by roughly 10%. A loss of 10% of available capacity with just one power plant outage is challenging for a system operator to accommodate, especially when most other power plants are already being fully utilized and any power plants not currently online are highly unreliable. In contrast, the unexpected loss of even the largest power plant on the U.S. mainland is much more manageable because of the larger pool of generation resources that can be tapped.

Figure 3-3 shows estimated LOLE for the Base Case by month. The green line represents the average estimated LOLE, while the shading around the middle line represents the calculated monthly LOLE distribution's 10% low and 90% high values for each month.

Figure 3-3: Base Case Calculated Loss of Load Expectation by Month



For example, for October 2024, the estimated average LOLE was approximately 6 days, with the worst 10% of simulations having 9 days of LOLE, while the best 10% of simulations had 3 LOLE days. As a result, one might expect LOLE for October 2024 to fall somewhere between the range of 3 days to 9 days, with 6 days being the most likely outcome.

Estimated LOLE was found to be highest from July through October. For these months, system load is higher because of high heat and humidity driving increased customer demands for air conditioning. Meanwhile, some generators schedule planned maintenance outages during this period. For most other utilities in the U.S., generator reliability is sufficiently good that maintenance outages can be scheduled during months of low electricity demand, so that most/all capacity is available during peak months. However, because of the high forced outage rates and the long average outage durations associated with Puerto Rico's thermal power plant fleet, there is minimal scheduling flexibility for maintenance planning: any plant that is not broken down has a reasonable chance that it will be called upon by the system operator to generate electricity. Unfortunately, multiple thermal power plants are unavailable during most hours of the year in Puerto Rico, even during the hottest summer months when maximum generation fleet availability is most desirable.

3.1.2 Loss of Load Hours

Loss of load hours (LOLH) is a measure of how many hours it can be expected that generation resources will be inadequate to serve system load.

The estimated LOLH in the Base Case is 154.2 hours, implying that Puerto Rico electricity customers should expect that, on average, there will be 154.2 hours during FY2025 in which generation resources will be deficient. By comparison, a utility achieving the industry standard LOLE of 0.1 day per year would be expected to experience about 2.4 hours LOLH (2.4 hours of generation shortfall per year). Thus, Puerto Rico's estimated Base Case LOLH is 64 times higher than the industry standard.

While estimated LOLH for the Base Case is 154.2 hours, note that in any one simulation LOLH varied between a minimum of 57 hours and a maximum of 310 hours. A histogram of the distribution of estimated LOLE outcomes from the 2,000 simulations is presented below in Figure 3-4.

Figure 3-4: Base Case Loss of Load Hours Probability Distribution

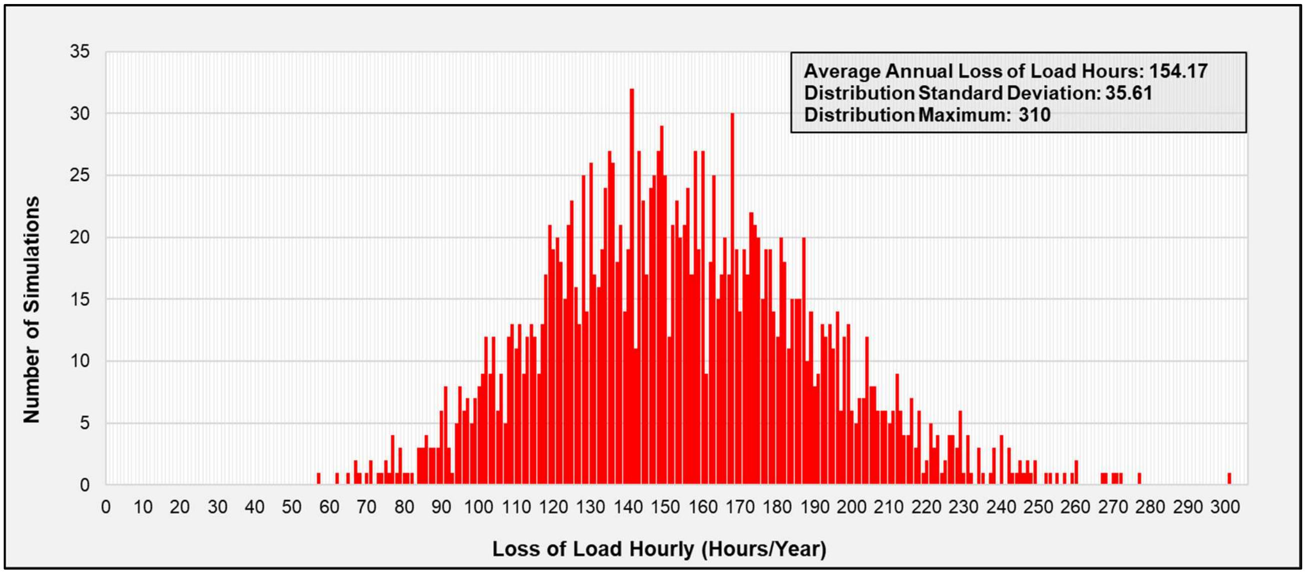
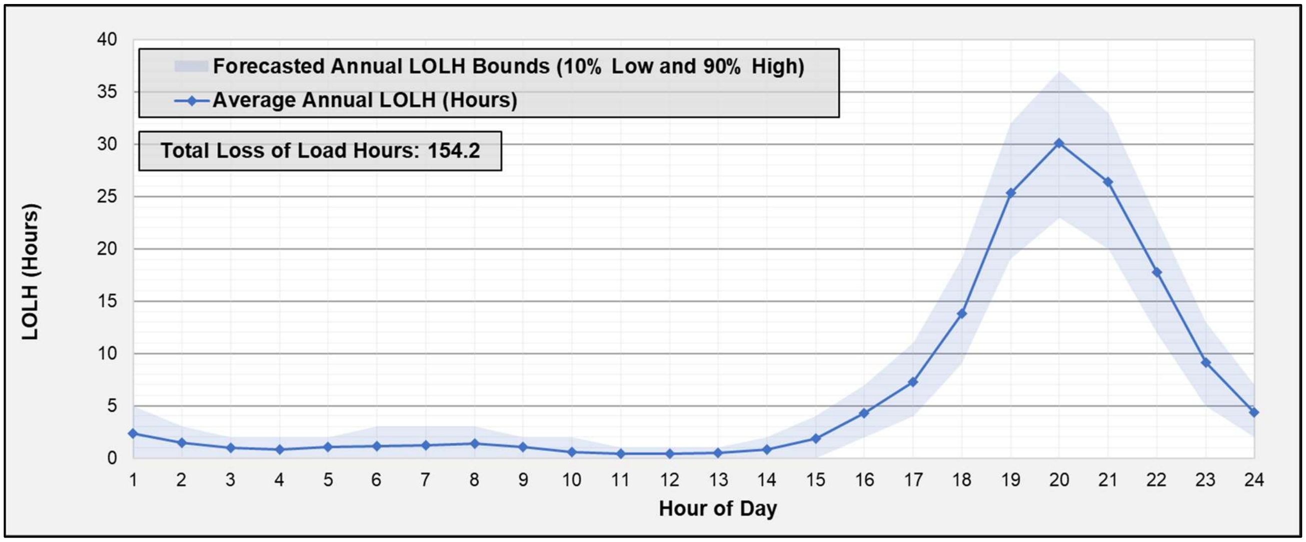


Figure 3-5 presents the average number of LOLH (for all the 2,000 simulations), broken out by hour of the day. Similar to the monthly LOLE presented in Figure 3-3, the shading represents the calculated annual LOLH distribution's 10% low and 90% high values for each hour. The majority of LOLH are observed during the evening hours, when system load is highest and when solar production is diminished or unavailable. Approximately 74% of the observed LOLH in the resource adequacy simulation was found to occur between 6:00 p.m. and 11:00 p.m.

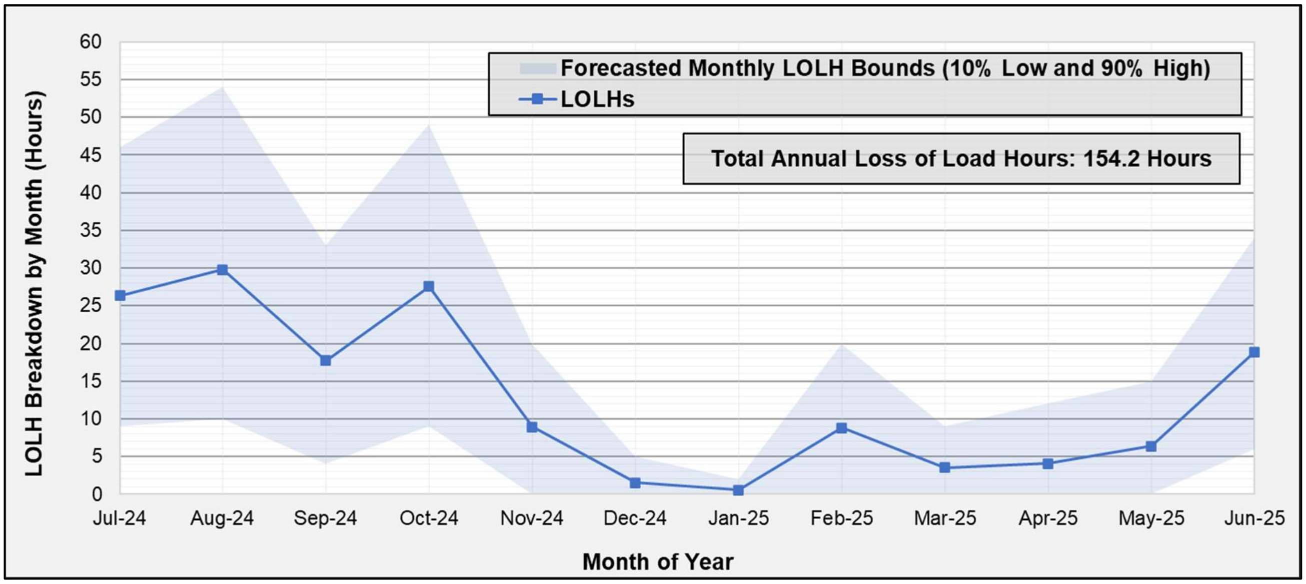
Figure 3-5: Base Case Calculated Loss of Load Hours by Hour of the Day



From the perspective of improving system resource adequacy, the above results indicate that the most effective solutions will be those targeted at being able to help meet load during the evening peak. For example, the addition of solar electricity generation helps system resource adequacy only during hours when the sun is up, which reflects just over a third of the hours when the simulated LOLH were found to occur. As such, the results in Figure 3-5 illustrate why additional solar generation will have little impact on improving resource adequacy in Puerto Rico. If a generation shortfall event spanned an entire day (i.e., a forced outage to a large thermal generator), additional solar would help to mitigate potential loss of load during the middle of the day (and thus reduce mid-day LOLH) but would not provide much help in preventing load-shed from occurring in the evening.

Figure 3-6 below shows LOLH in the Base Case assessment broken out by month. LOLH is found to be highest during August and October because these months respectively correspond to the highest MW of units scheduled for planned outage in combination with high system load during these months. An additional contribution to LOLH is maintenance outages of large generators. During maintenance outages of large generators, any additional forced outages to other generators could result in LOLH. Similar to the previous graph, the shading represents the calculated monthly LOLH distribution’s 10% low and 90% high values – the shading provides an illustration of the range of calculated potential LOLH outcomes for each month.

Figure 3-6: Base Case Calculated Loss of Load Hours by Month of the Year



3

3.1.3 Capacity Reserve Margins

Table 3-2 presents the average system capacity reserve margins estimated for FY2025 in the Base Case by hour and month, based on an average over all the simulations performed, so that the values shown in table 3-2 represent the middle of the probability distribution. Each value in the figure reflects the MW of available capacity on average during that hour and month. Available capacity includes both the available capacity of thermal power plants and any dependable capacity from renewable power plants.

Table 3-2: Base Case Capacity Reserve Margins by Hour and Month

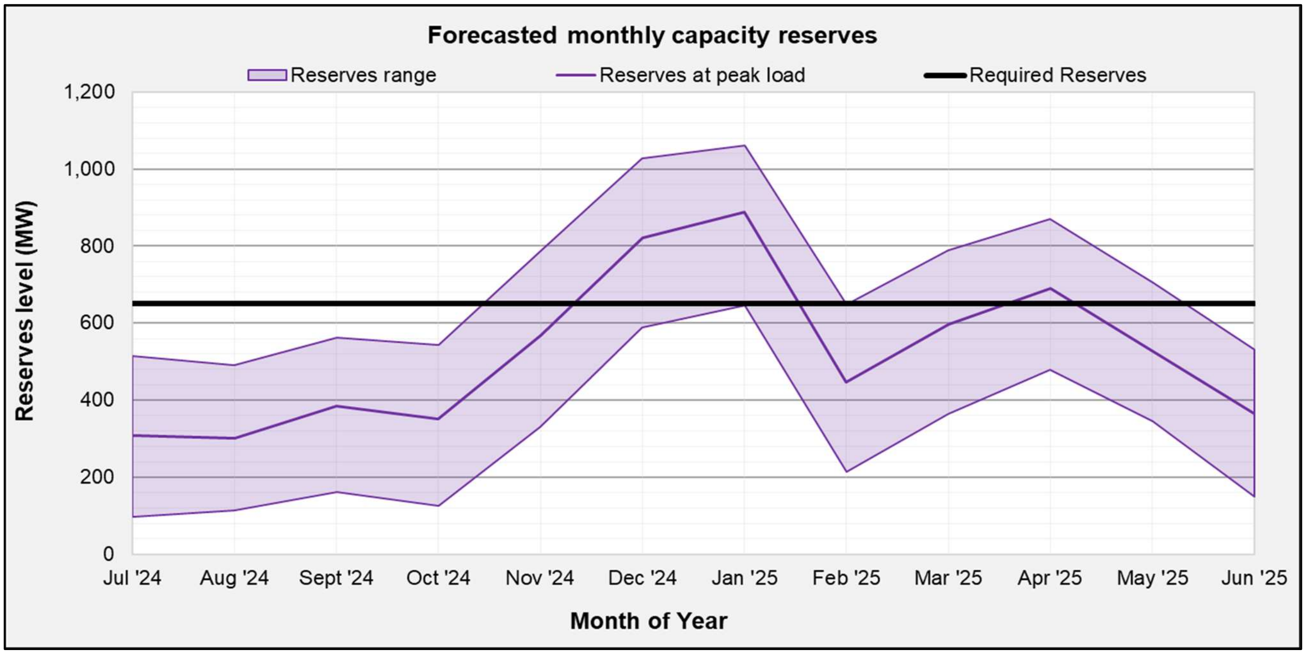
Hour of Day	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Average by Hour
	Month of Year												
1	692	680	861	768	1,072	1,195	1,385	899	1,050	905	885	768	**930**
2	787	739	931	826	1,148	1,250	1,453	966	1,125	937	945	844	**996**
3	847	781	980	867	1,200	1,289	1,490	1,006	1,170	957	989	903	**1,040**
4	874	797	999	878	1,215	1,295	1,491	1,008	1,178	958	1,000	928	**1,052**
5	865	773	973	838	1,161	1,257	1,417	935	1,112	938	985	931	**1,015**
6	889	781	989	830	1,114	1,208	1,306	840	1,055	932	989	946	**990**
7	858	778	1,004	845	1,132	1,216	1,316	851	1,073	935	971	914	**991**
8	837	761	986	836	1,132	1,220	1,296	852	1,081	943	965	903	**984**
9	878	788	1,011	863	1,188	1,282	1,350	916	1,145	991	1,024	958	**1,033**
10	956	849	1,052	905	1,255	1,378	1,443	1,032	1,261	1,080	1,126	1,057	**1,116**
11	1,010	879	1,074	922	1,279	1,448	1,513	1,119	1,347	1,143	1,181	1,111	**1,169**
12	1,044	906	1,074	913	1,281	1,495	1,566	1,188	1,411	1,189	1,205	1,155	**1,202**
13	1,033	901	1,038	880	1,246	1,494	1,589	1,218	1,431	1,206	1,197	1,143	**1,198**
14	969	861	958	812	1,175	1,438	1,569	1,199	1,406	1,192	1,149	1,082	**1,151**
15	848	774	819	710	1,046	1,331	1,473	1,099	1,312	1,132	1,039	970	**1,046**
16	731	666	691	597	885	1,192	1,310	947	1,152	1,039	928	822	**913**
17	647	579	616	530	775	1,070	1,183	793	984	953	831	706	**806**
18	545	489	506	408	614	880	999	644	827	863	739	605	**676**
19	390	350	397	352	571	821	887	474	634	732	587	446	**553**
20	315	301	384	356	568	827	895	448	596	690	529	364	**523**
21	308	320	432	402	611	864	942	483	627	695	542	367	**549**
22	370	390	527	483	699	932	1,027	562	704	734	600	425	**621**
23	473	492	653	604	827	1,031	1,147	676	817	798	696	547	**730**
24	596	596	769	695	964	1,127	1,280	801	946	854	799	667	**841**
Average by Month	**740**	**676**	**822**	**713**	**1,007**	**1,189**	**1,305**	**873**	**1,060**	**950**	**913**	**815**	

The "heat map" in Table 3-2 has conditional formatting of gradient shades that indicate the hours of the day and the months of the year in which LOLH risk is higher (red) or lower (green). In general, consistent with LUMA's capacity reserve policy described in Section 2.5, times when the available capacity drops below 650 MW correspond to a higher risk of demand not being served, as the loss of a single large generator during these times can result in a shortfall of generation to meet demand. Consistent with the findings that LOLH is greatest during the evening hours, the average available capacity to serve load is always lowest in the evening hours, when system load is highest.

Given that the peak load on the Puerto Rico electricity system is approximately 3,000 MW, the values presented in Table 3-2 indicate that, while the PRM in Puerto Rico is nominally 50%, the ratio of actual available capacity to load is substantially lower than 50%, due to the high forced outage rates of many of the thermal power plants on the island.

Figure 3-7 shows the forecasted Base Case amount of reserve capacity in megawatts (MW) at the peak load hour of each month, in comparison to required reserve levels (as described in Section 2.5) that average approximately 650 MW (black line).

Figure 3-7: Base Case Capacity Reserves at Monthly Peak Load Hour



For example, in July, the forecasted average reserve capacity level at peak load hour is roughly 310 MW, with a probable lowest amount of 95 MW, and a probable maximum of 510 MW. From June to October, even the probable maximum reserve capacity levels at peak hour are lower than the ~650 MW of capacity that LUMA's reserve policy has set as its standard to assure acceptable system reliability. This is a clear illustration of the degree of resource inadequacy that Puerto Rico's electricity system faces, especially during the summer months.

3.2 Resource Adequacy Under Force Majeure Scenario

As shown by Hurricane Maria in 2017, the January 2020 6.7 magnitude earthquake and Hurricane Fiona in 2022, natural disasters can be devastating to Puerto Rico's electricity system. In addition to damaging transmission and distribution infrastructure, such catastrophes also can knock out power plants for months. Given that the Puerto Rico electricity system is already resource-deficient in the Base Case, this section describing a "Force Majeure" Scenario aims to quantify how much more resource-deficient the system could become if it experienced a large disaster during FY 2025.

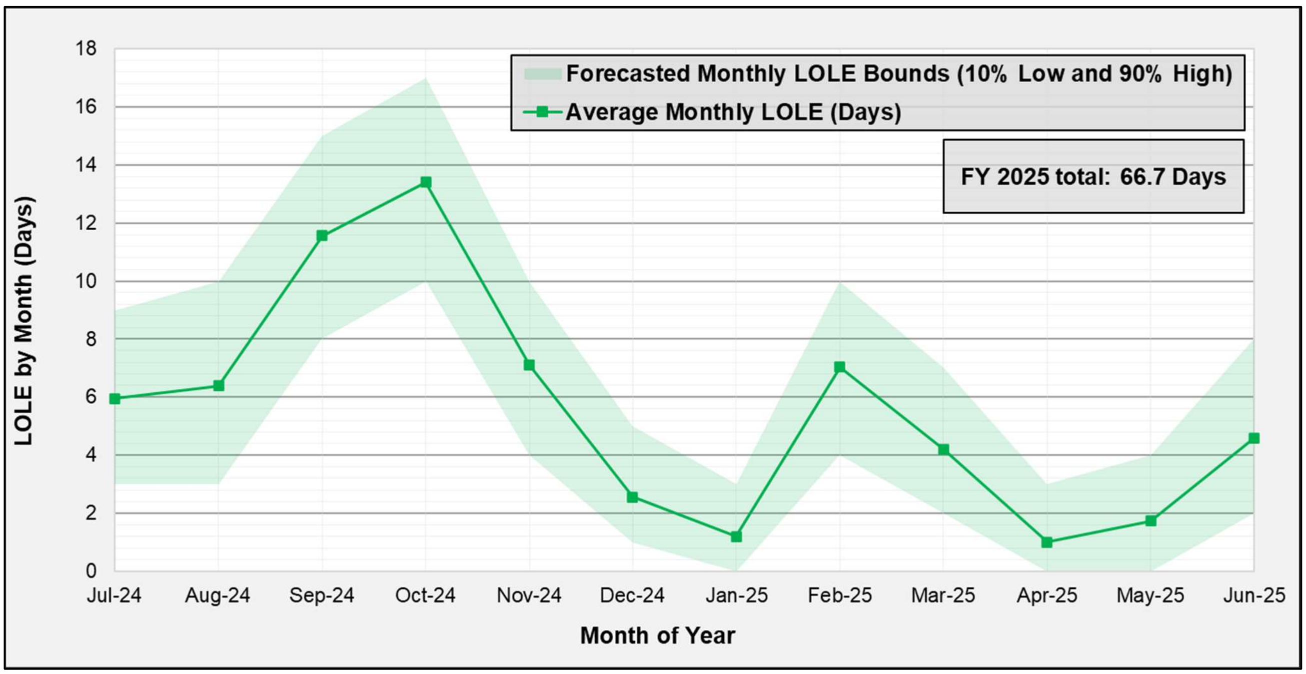
Resource adequacy under the Force Majeure Scenario was modeled by increasing assumed forced outage rates at Puerto Rico's thermal power plant fleet relative to the assumptions used in the Base Case. This modeling approach was developed from experience gained in the wake of Hurricane Fiona. Due to the damages caused by the hurricane and the duration required to restore the plants to operational status, thermal generation forced outage rates were 60% higher than historical averages over the first three months after the hurricane and remained 50% above historical levels six months after the hurricane.

Reflecting this experience, the forced outage rate assumptions for all thermal generation units in the Force Majeure Scenario were increased by 60% from Base Case levels for three months after a disaster (assumed to occur on September 1, 2024), then were increased by 50% from Base Case levels over the next three months (January through March 2025), with forced outage rates returning to Base Case levels thereafter.

The resulting estimated LOLE for this Force Majeure Scenario was 66.7 days/year (compared to 36.2 days/year for the Base Case) and the estimated LOLH was 340 hours/year (compared to 154 hours/year for the Base Case). In summary, resource adequacy metrics in Puerto Rico would worsen by about a factor of two from Base Case levels if a major disaster were to occur.

Figure 3-8 shows the estimated LOLE under the Force Majeure Scenario by month. The green line represents the average estimated LOLE, while the shading around the middle line represents the calculated monthly LOLE distribution's 10% low and 90% high values for each month.

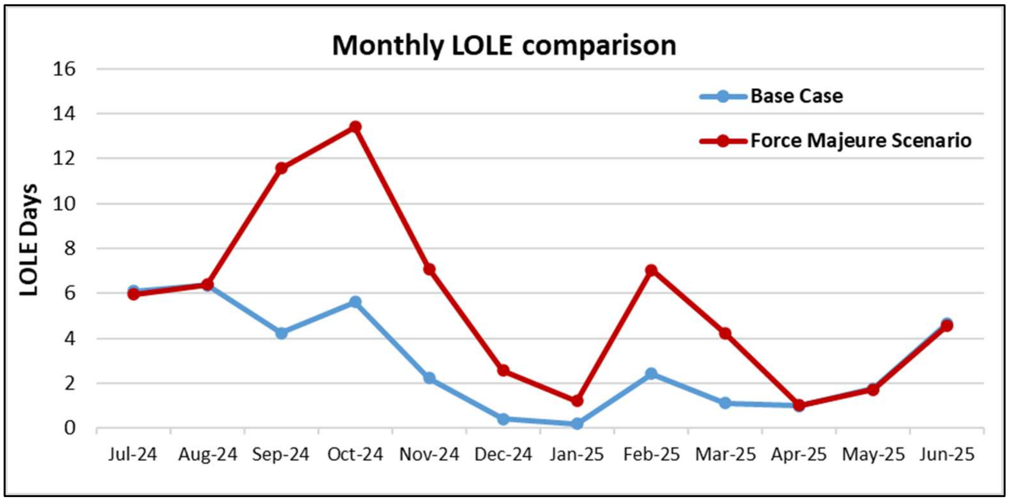
Figure 3-8: LOLE in Force Majeure Scenario



For example, for October 2024, the average estimated LOLE under the Force Majeure Scenario was approximately 13 days, with the worst 10% of simulations producing 17 days of LOLE, while the best 10% of simulations producing 10 LOLE days. As a result, one might expect LOLE for October 2024 under the Force Majeure Scenario to fall somewhere between the range of 10 days to 17 days, with 13 days the most likely.

Figure 3-9 compares the estimated LOLE under the Base Case to the estimated LOLE under the Force Majeure Scenario, illustrating the incremental effect of a major disaster on the risk of load-shed from September to March.

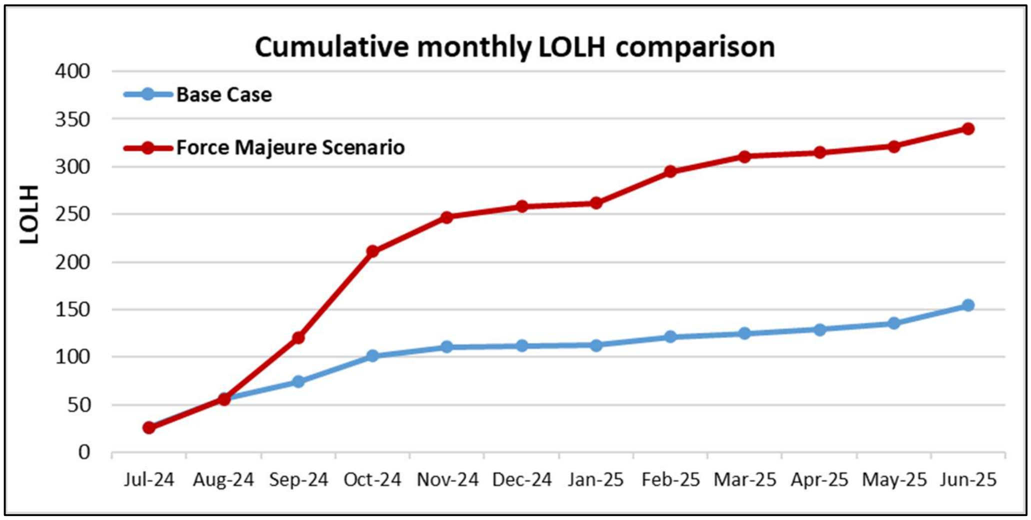
Figure 3-9: LOLE Comparison Between Base Case and Force Majeure Scenario



Comparing the modeling results under the Base Case vs. the Force Majeure Scenario implies that LOLE in October 2024 would be about 7 days higher (13 days vs. 6 days) due to specific impacts of the Force Majeure Scenario. Estimated LOLE increases attributable to the Force Majeure Scenario fall to modest levels during December 2024 and January 2025 because of lower demand in the winter season, Then, estimated LOLE increases due specifically to the effects of the Force Majeure Scenario rebound somewhat during February and March 2025, as system peak demands increase back to levels that the aggregate available generation will sometimes struggle to meet.

Similarly, estimated LOLH is notably higher in the Force Majeure Scenario than in the Base Case. Cumulative LOLH (i.e., a running total of the number of load loss hours over the course of the year) for both the Force Majeure Scenario and the Base Case is illustrated in Figure 3-10, showing a major rise in estimated LOLH in September 2024 immediately after the assumed date of the disaster. Force Majeure Scenario

Figure 3-10: Cumulative Monthly LOLH Comparison Between Base Case and Force Majeure Scenario

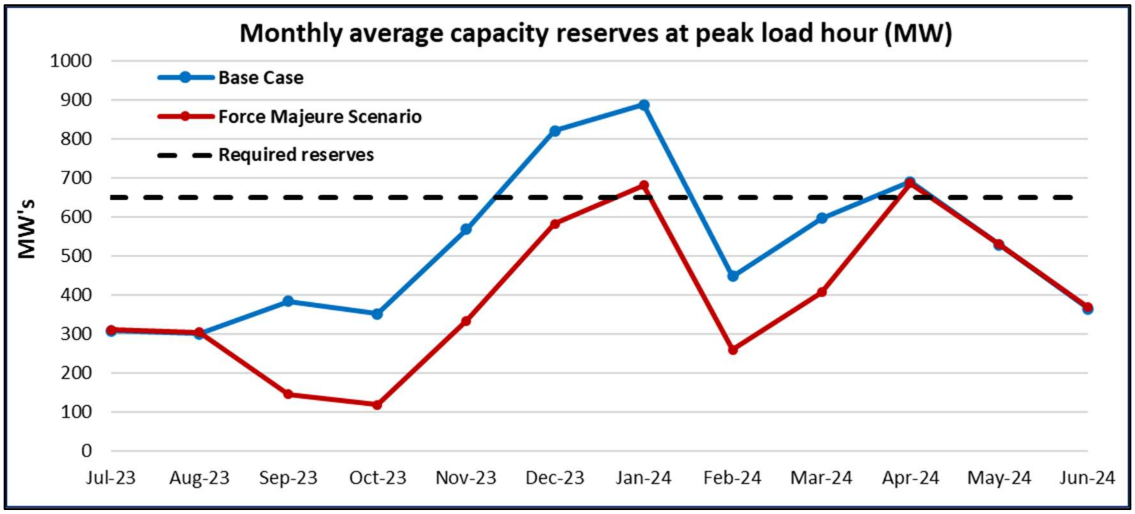


After December 2024, the difference in cumulative LOLH between the Force Majeure Scenario and the Base Case does not widen much further, as forced outage rates begin falling back towards normal and peak demands lessen. Therefore, most of the reduction in resource adequacy caused by a hurricane will be experienced by electricity customers before the onset of winter, with electricity system performance returning to approximately Base Case levels thereafter.

Another consequence of the Force Majeure Scenario is that the reserve capacity level decreases. Higher forced outage rates mean less generation availability, and therefore lower reserve capacity levels.

Figure 3-11 compares monthly reserve capacity levels at peak load hours under the Base Case and the Force Majeure Scenario. Note that the lowest months of forecasted capacity reserves at peak load hours under the Base Case are in July and August 2024 at approximately 300 MW, while reserves at peak hour fall to approximately 100 MW for September and October 2024 under the Force Majeure Scenario (This is to be expected, as September and October would be the most affected months, transpiring immediately after the hurricane's impact). Capacity reserve levels at such low levels will put the electricity system at a very high risk of experiencing load-shed events because the outage of just a small amount of capacity will lead to a generation shortfall.

Figure 3-11: Capacity Reserves at Monthly Peak Demand: Base Case vs Force Majeure Scenario



Also, as Table 3-3 below shows, reserve capacity levels level at peak demand hours in the Force Majeure Scenario fall far below 650 MW – in fact, falling below 200 MW in the early evening hours of September and October – thus leading to a very high risk of load shed events.

Table 3-3: Reserve Margin Capacity for Force Majeure Scenario

	Month of Year												
Hour of Day	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Average by Hour
1	695	684	629	536	839	957	1,178	712	861	895	886	770	**804**
2	789	743	698	593	916	1,013	1,246	779	937	928	946	848	**870**
3	849	784	746	634	969	1,051	1,282	818	981	948	990	906	**913**
4	877	800	766	645	983	1,058	1,282	820	989	949	1,001	932	**925**
5	868	777	739	605	929	1,020	1,208	747	923	930	986	935	**889**
6	891	784	754	597	883	970	1,099	651	866	924	990	950	**863**
7	861	781	769	612	901	978	1,108	662	884	928	971	918	**864**
8	840	764	751	602	902	983	1,089	662	891	936	966	908	**858**
9	880	790	776	629	958	1,044	1,143	726	955	984	1,025	963	**906**
10	958	851	816	671	1,024	1,141	1,235	842	1,071	1,073	1,126	1,062	**989**
11	1,011	883	837	689	1,049	1,212	1,305	928	1,158	1,136	1,182	1,116	**1,042**
12	1,045	909	836	681	1,050	1,257	1,359	997	1,222	1,184	1,205	1,160	**1,075**
13	1,034	904	800	648	1,015	1,256	1,382	1,028	1,242	1,200	1,197	1,147	**1,071**
14	971	865	721	579	944	1,200	1,362	1,010	1,217	1,187	1,150	1,086	**1,024**
15	850	778	582	477	814	1,093	1,265	910	1,123	1,127	1,040	973	**919**
16	733	669	453	364	651	953	1,103	757	964	1,035	929	825	**786**
17	649	583	377	297	541	832	976	604	795	949	831	710	**679**
18	547	493	268	175	380	642	793	455	638	859	739	608	**550**
19	392	354	160	118	337	582	681	286	444	729	587	450	**427**
20	318	305	145	123	334	588	689	260	406	686	529	368	**396**
21	311	324	194	167	377	625	736	295	437	692	542	370	**423**
22	373	393	288	249	466	695	820	373	515	731	601	428	**494**
23	476	495	414	371	594	794	940	488	627	795	697	551	**604**
24	598	600	530	462	731	890	1,074	614	756	851	800	670	**715**
Average by Month	**742**	**680**	**585**	**480**	**774**	**951**	**1,098**	**684**	**871**	**944**	**913**	**819**	
Lowest amount of reserves	**311**	**305**	**145**	**118**	**334**	**582**	**681**	**260**	**406**	**686**	**529**	**368**	

3.3 Resource Adequacy Sensitivity Analyses

To evaluate how much resource adequacy of the Puerto Rico electricity system might be affected due to changes that might reasonably occur in electricity supply or demand, this report also presents the modeling results from 20 sensitivity analyses in which certain assumptions were altered from those used in the Base Case. Some of these sensitivity analyses will inevitably reveal a worsening of resource adequacy, having either reduced resource availability assumptions or increased electricity demand assumptions. Conversely, other sensitivity analyses will inevitably reveal an improvement in resource adequacy, having either increased resource availability assumptions or reduced electricity demand assumptions.

The 20 sensitivity analyses are grouped into the following six themes:

- Unavailability of Existing Thermal Resources
- Addition of Standalone Solar Resources
- Addition of Standalone Battery Energy Storage System (BESS) Resources
- Addition of BESS-Paired Solar Resources
- Addition of Other Resources
- Changes to Electricity Demand

Each of these sensitivity themes, including an overview of key assumptions and findings, is presented in the sections that follow. Detailed descriptions and results of each sensitivity analysis are presented in Appendix A.

3.3.1 Unavailability of Existing Thermal Resources

Three sensitivity analyses were undertaken to analyze the negative impact on resource adequacy if selected thermal power plants were not available for FY2025:

- **Unavailability of Emergency Generation (TM generators):** This sensitivity analyzes how the system would be affected if FEMA had not provided 340 MW of trailer-mounted (TM) generators to the island in 2023.
- **Unavailability of Costa Sur 6:** This sensitivity analyzes the effect of having not just one of the two largest thermal power plants (Aguirre 2, 350 MW) offline for the entire fiscal year as modeled in the Base Case, but also having a second similarly-sized power plant (Costa Sur 6, 350 MW) out of operation for the entire study period.
- **Unavailability of AES powerplant:** This sensitivity analyzes the impact that the unavailability of the AES powerplant (454 MW) would have on resource adequacy. It should be noted that AES is slated to retire by the end of 2027, so this sensitivity provides insight into the incremental effect on system reliability when AES retires if the Puerto Rico electricity system does not change materially from its current state.

Figure 3-12 below demonstrates how much these sensitivity analyses related to the unavailability of existing thermal power plants can negatively affect resource adequacy. The analysis indicates that any one of these three sensitivity analyses would have a much more adverse impact on resource adequacy than a major hurricane. Loss of load expectation (LOLE) would likely exceed 100 days (vs. 36.2 in the Base Case and 66.7 in the Force Majeure Scenario) and loss of load hours (LOLH) would likely exceed 500 hours (vs. 154.2 in the Base Case and 339.9 in the Force Majeure Scenario).

Figure 3-12: Impacts on LOLE and LOLH From Thermal Power Plant Unavailability Sensitivity Analyses

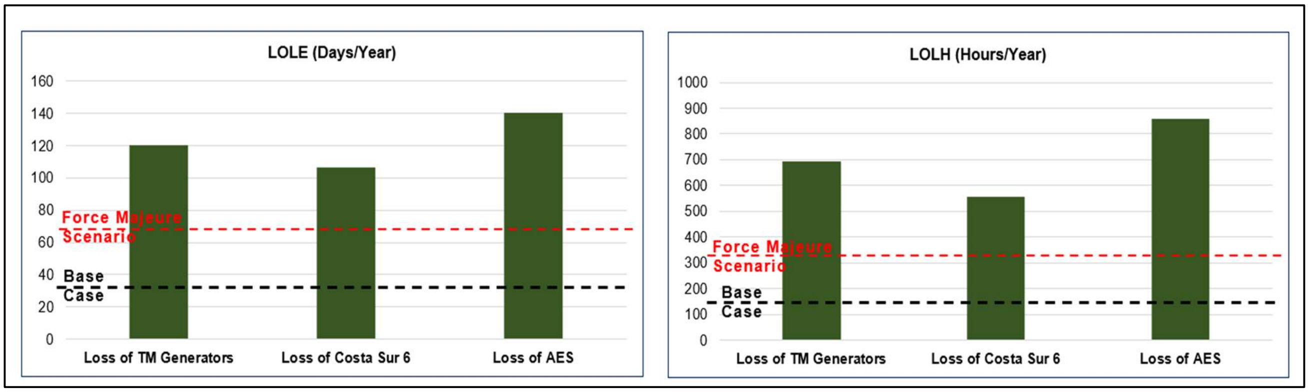


Figure 3-12 illustrates how valuable the TM generators are to the current resource adequacy of the Puerto Rico electricity system, as LOLE and LOLH would approximately triple from Base Case Levels if the TM generators were not available. Figure 3-12 also illustrates how much Puerto Rico electricity service would suffer from a year-long loss of a second major generating facility (in addition to the year-long outage assumed for Aguirre 2 in the Base Case).

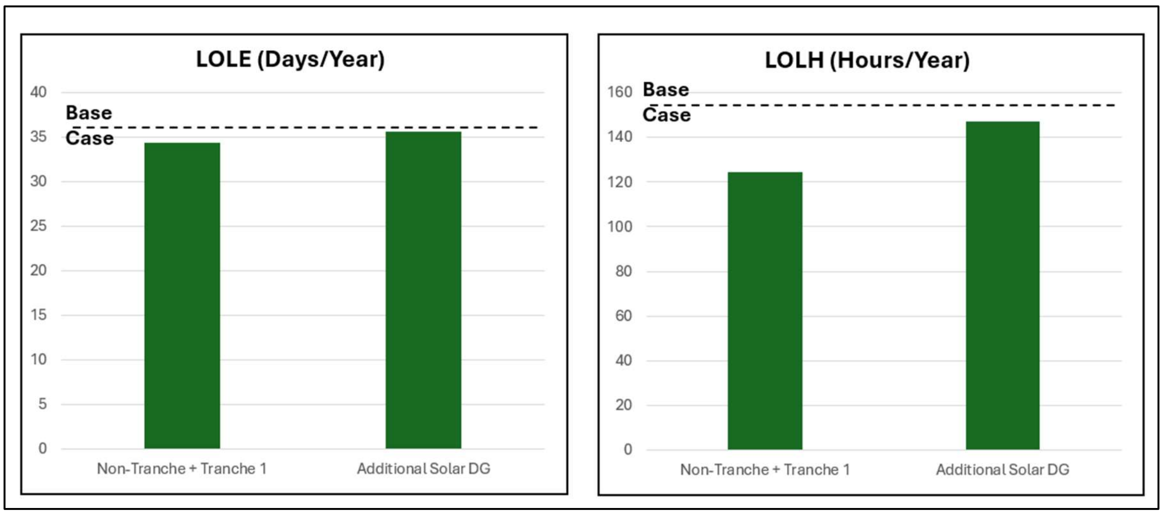
3.3.2 Addition of Standalone Solar Resources

Two sensitivity analyses were undertaken to analyze the hypothetical positive impact on resource adequacy if additional PV resources had already been installed and were available to supply electricity in Puerto Rico during FY2025:

- **Non-Tranche + Tranche 1 Solar-Only Projects:** This sensitivity illustrates the impact of adding approximately 555 MW of Tranche 1 solar projects and 200 MW of Non-Tranche solar projects to the Base Case model.
- **Additional Distributed Solar PV (DG):** This sensitivity illustrates the impact of adding approximately 115 MW of additional distributed rooftop PV to the system.

Figure 3-13 shows that the addition of even as much as 555 MW of new standalone solar generation to the Puerto Rico electricity system does not significantly improve resource adequacy.

Figure 3-13: Impacts on LOLE and LOLH From Solar Addition Sensitivity Analyses



Estimated LOLE and LOLH fall slightly to levels only marginally below those found from the Base Case, remaining far above levels associated with a highly reliable electricity system as found on the U.S. mainland. This is because standalone solar resources do not produce meaningful volumes of electricity in the early evening when Puerto Rico's peak electricity demands occur, which in turn is when Puerto Rico's electricity grid faces the greatest needs for additional resources.

3.3.3 Addition of Standalone Battery Energy Storage System (BESS) Resources

Five sensitivity analyses were undertaken to analyze the hypothetical positive impact on resource adequacy if certain projects involving standalone battery energy storage systems (BESS) planned for Puerto Rico had already been installed and were available to supply electricity during FY2025:

- **Tranche 1 BESS-Only Projects:** This sensitivity simulation evaluates the impact of adding 350 MW of 4-hr duration BESS that is anticipated to be installed in response to the Tranche 1 RFPs.
- **ASAP BESS Project:** This sensitivity simulation evaluates the impact of adding 360 MW of 4- hr duration BESS, as being planned by LUMA in its ASAP program.

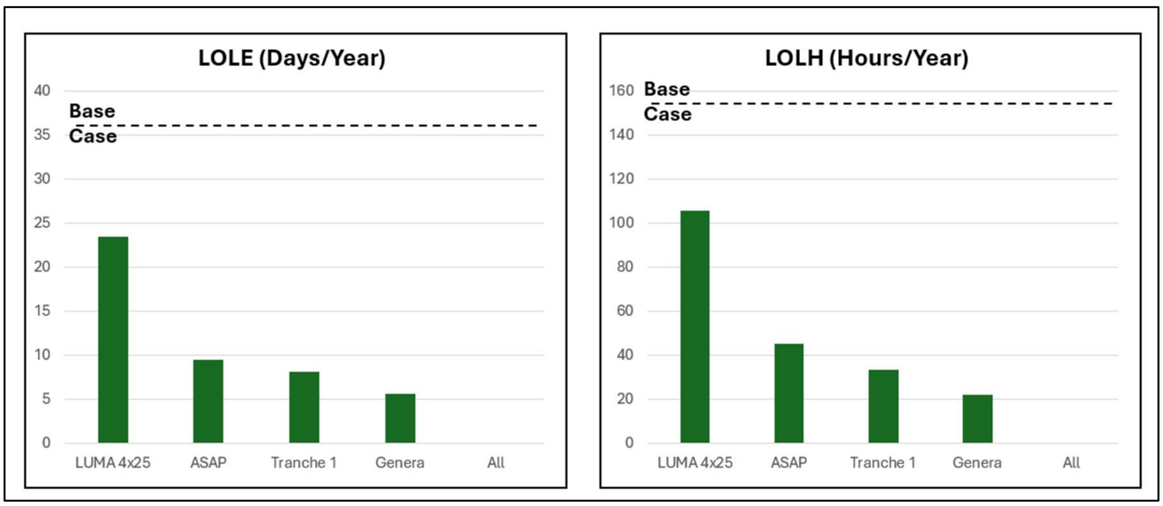
- **Genera's BESS Projects:** This sensitivity simulation evaluates the impact of adding 430 MW of 4-hr duration BESS as being planned by Genera to be installed at some of the PREPA-legacy power plants operated by Genera.

- **LUMA'S 4X25 BESS Project:** This sensitivity simulation evaluates the impact of adding 100 MW of 4-hr duration BESS as being planned by LUMA to add to selected substations to improve grid reliability.

- **Tranche 1 + ASAP + Genera + LUMA'S 4X25 BESS-Only Projects:** This sensitivity simulation evaluates the impact of adding a total of 1,240 MW of 4-hr duration BESS associated with the four sensitivity analyses discussed immediately above.

In contrast to standalone solar resources, the addition of standalone BESS resources promises to significantly improve resource adequacy on the Puerto Rico electricity grid. As shown in Figure 3-14, all sensitivity analyses based on the addition of standalone BESS meaningfully reduce expected LOLE and LOLH relative to the Base Case.

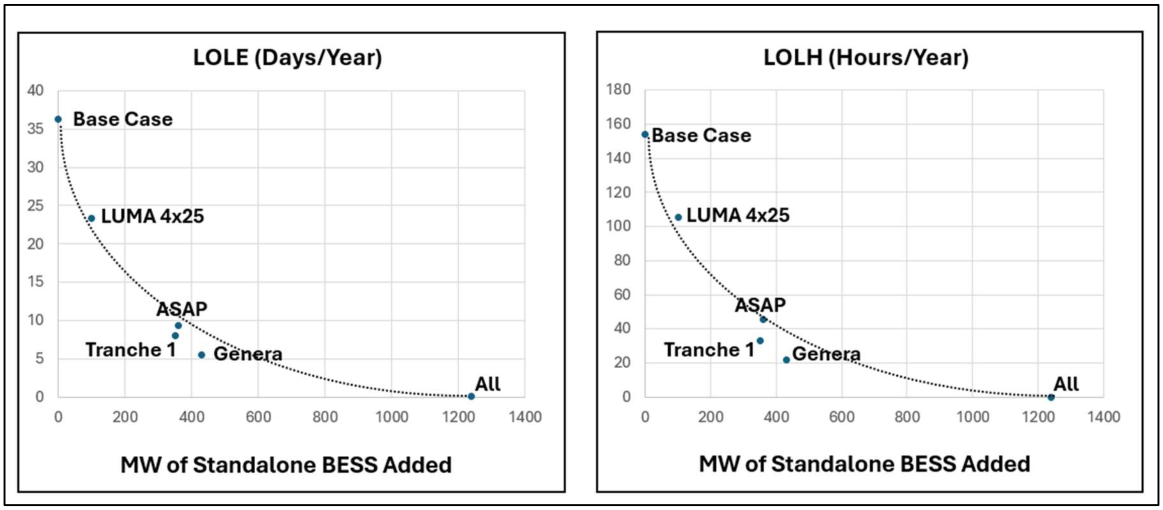
Figure 3-14: Impacts on LOLE and LOLH From BESS Addition Sensitivity Analyses



In the most expansive standalone BESS (" All") sensitivity examined, involving 1,240 MW of 4-hr duration energy storage to be added, the resulting LOLE and LOLH estimates are consistent with the resource adequacy targets employed by many utilities in North America to achieve 0.1 days per year loss of load event.

As Figure 3-15 indicates, major improvements to resource adequacy can be achieved even with much smaller increments of new BESS-based resources.

Figure 3-15: Impacts on LOLE and LOLH From Adding BESS Resources



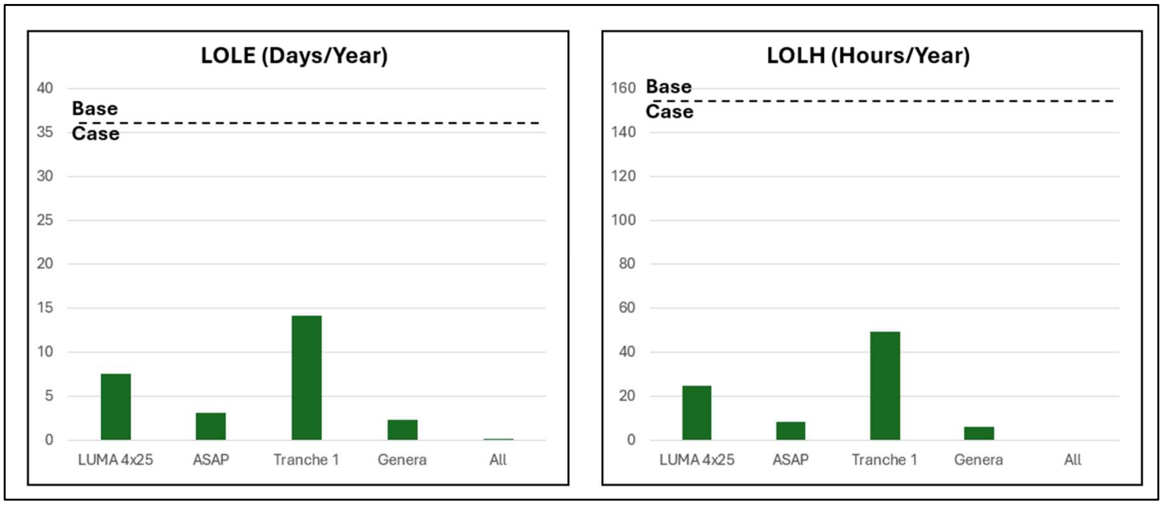
3.3.4 Addition of BESS-Paired Solar Resources

Five sensitivity analyses analyze the hypothetical positive impact on resource adequacy if approximately 555 MW of reasonably anticipated PV projects (i.e., the Non-Tranche and Tranche 1 solar projects) and varying increments of the 4-hr duration BESS projects planned for Puerto Rico had already been installed and were available to supply electricity during FY2025:

- **Tranche 1 (Solar + BESS) Projects:** This sensitivity simulation illustrates the impact of adding approximately 555 MW of new solar generation in combination with a total of 350 MW (150 MW standalone and 200 MW solar-paired) of 4-hr duration BESS. The total amount of added solar and BESS resources for this simulation is consistent with the total amount from the Non-Tranche solar projects and Tranche 1 solar/BESS projects.
- **Tranche 1 (Solar + BESS) + ASAP BESS Project:** This sensitivity simulation illustrates the impact of adding approximately 555 MW of new solar generation in combination with a total of 710 MW (510 MW standalone and 200 MW solar-paired) of 4-hr duration BESS.
- **Tranche 1 (Solar + BESS) + Genera's BESS Project:** This sensitivity simulation illustrates the impact of adding approximately 555 MW of new solar generation in combination with a total of 780 MW (580 MW standalone and 200 MW solar-paired) of 4-hr duration BESS.
- **Tranche 1 (Solar + BESS) + LUMA's 4X25 BESS Project:** This sensitivity simulation illustrates the impact of adding approximately 555 MW of new solar generation in combination with a total of 450 MW (250 MW standalone and 200 MW solar-paired) of 4-hr duration BESS.
- **Tranche 1 (Solar + BESS) + ASAP + Genera + LUMA's 4X25 Projects:** This sensitivity simulation illustrates the impact of adding approximately 555 MW of new solar generation in combination with a total of 1240 MW (1040 MW standalone and 200 MW solar-paired) of 4-hr duration BESS.

As shown in Figure 3-16, the addition of BESS-paired solar capacity to the Puerto Rico electricity system also improves resource adequacy. The addition of BESS to solar makes a big difference in impact on resource adequacy: recall from Section 3.3.2 above that standalone solar capacity additions without BESS resources do not have a significant effect on resource adequacy, as PV systems are unable to supply meaningful volumes of electricity during peak demand periods when generation resources are most needed.

Figure 3-16: Impacts on LOLE and LOLH From BESS-Paired Solar Addition Sensitivity Analyses



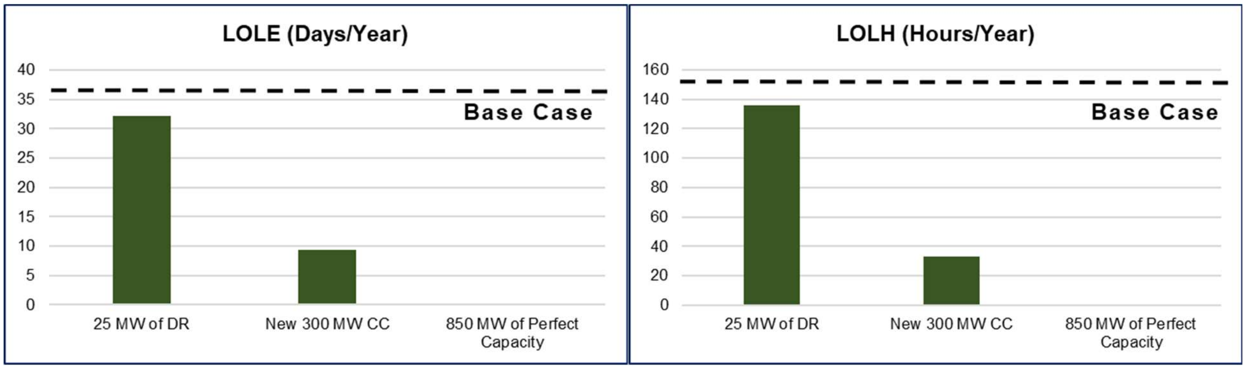
3.3.5 Addition of Other Resources

Three sensitivity analyses were undertaken to analyze the hypothetical positive impact on resource adequacy if other initiatives to add resources to the Puerto Rico electricity system had already been completed and were operationally available during FY2025:

- **Estimated Perfect Capacity Need:** This sensitivity simulation was based on a determination of how much additional "perfect" generation capacity (i.e., new generating capacity that can operate without any outages or reduction in available capacity for all 8,760 hours in a year) would need to be added to the Puerto Rico electrical system in order to meet the electric utility industry LOLE target of 0.10 days/year. (Equivalently, perfect capacity is equivalent to a constant MW reduction in load for every hour of the year.) The results of the analysis indicated that 850 MW of perfect capacity would enable Puerto Rico to achieve a 0.10 days/year LOLE target. While no generator is "perfect," identifying how much perfect capacity would be needed helps to provide a best-case estimate of incremental resources required to bring Puerto Rico's electricity system in line with the resource adequacy typically found on the U.S. mainland.
- **New Flexible Thermal Resource:** This sensitivity considers the addition of a new 300 MW Combined Cycle (CC) thermal unit offering low forced outage rates and high operational dispatch flexibility to the Puerto Rico electricity system (although no such capacity additions are presently planned).
- **Demand Response (DR) Resources:** This sensitivity analysis illustrates the resource adequacy impact of adding 25 MW of demand response (DR) resources (i.e., short-term reductions in customer electricity demand during peak hours as requested by the system operator).

Findings from the sensitivity analyses related to the addition of other resources are presented in Figure 3-17 below.

Figure 3-17: Impacts on LOLE and LOLH From Addition of Other Resources Sensitivity Analyses



As might be expected, the addition of 25 MW of demand response (DR) resources only modestly improves resource adequacy, whereas the addition of a new 300 MW combined cycle (CC) power plant has a much larger positive impact. Even so, the expected LOLE and LOLH associated with the sensitivity based on the addition of a new 300 MW CC is effectively the same as the expected LOLE and LOLH that resulted from comparable additions of standalone BESS resources. Meanwhile, the Perfect Capacity sensitivity analysis described above determined that 850 MW of "perfect" capacity would yield an estimated 0.1 days/year LOLE, consistent with the planning targets used by many utilities in the U.S.

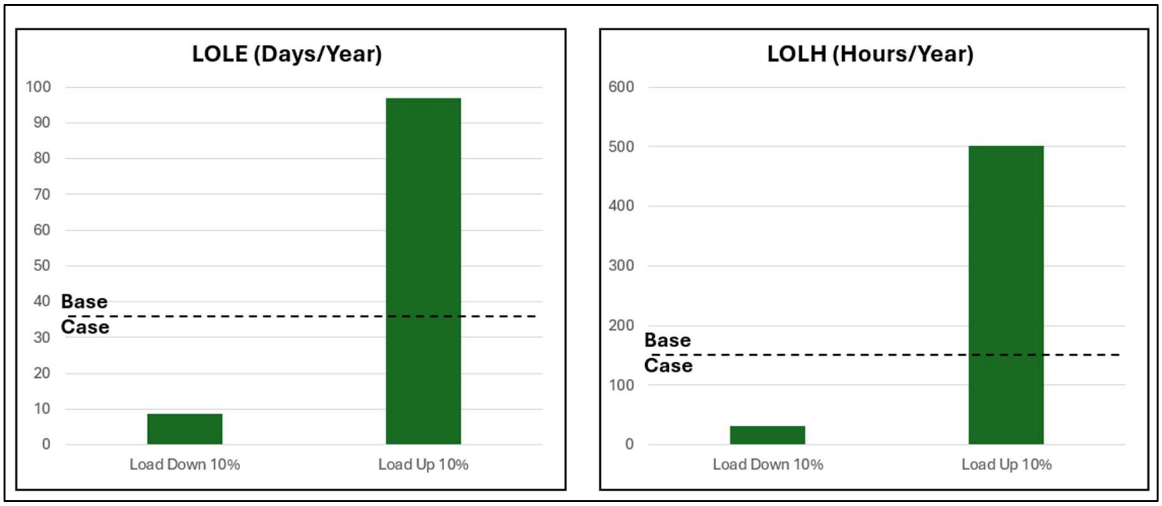
3.3.6 Changes to Electricity Demand

Three sensitivity analyses were undertaken to analyze the hypothetical impact on resource adequacy if Puerto Rico electricity demand patterns and levels during FY2025 were different from those assumed in the Base Case:

- **Load Sensitivity +10%:** This sensitivity investigates the negative impact on system resource adequacy by increasing the load by 10% from Base Case levels in each of the 8,760 hours of the year forecasted for FY2025.
- **Load Sensitivity -10%:** This sensitivity investigates the positive impact on system resource adequacy by decreasing the load by 10% from Base Case levels in each of the 8,760 hours of the year forecasted for FY2025.
- **Addition of Electric Vehicle (EV) Load:** This sensitivity evaluates the negative impact on system resource adequacy of increasing electricity demand from Base Case levels to account for the need to recharge an additional 6,000 Electric Vehicles (EVs) on the road in Puerto Rico. (While EVs have the potential to serve as an energy storage resource for the grid if/when vehicle-to-grid (V2G) capabilities become available in EVs and widely practiced by utilities. For this sensitivity, EVs are assumed to solely represent an increase in electricity demand and are not considered a V2G energy storage resource that can be dispatched by the system operator.)

Figure 3-18 presents the impacts on estimated LOLE and LOLH associated with a 10% decrease and a10% increase in hourly electricity demand in Puerto Rico. Figure 3-18 shows that a 10% swing either way in Puerto Rico's electricity demand affects resource adequacy greatly: favorably if demand falls by 10%, unfavorably if demand falls by 10%. The effects of a 10% reduction in load are comparable in magnitude to the effect of an additional 300-400 MW of supply-side resources (e.g., new 300 MW CC sensitivity, Tranche 1 BESS sensitivity), whereas the effects of a 10% increase in load are comparable in magnitude to those found in the sensitivity based on the loss of Costa Sur 6 for the year.

Figure 3-18: Impacts on LOLE and LOLH From Electricity Demand Sensitivity Analyses



The electric vehicle sensitivity analyses are not depicted in Figure 3-18 because the estimated LOLE and LOLH from those analyses are virtually identical to those found from the Base Case analysis. In other words, the addition of 6,000 EVs to the Puerto Rico automotive fleet is expected to have minimal impact on the resource adequacy of the Puerto Rico electricity grid.

Summarizing over all analyses, Table 3-4 presents estimated LOLE and LOLH model results from each of the resource adequacy analyses described in this report, including the Base Case, the Force Majeure Scenario, and each of the 20 sensitivity analyses.

Table 3-4: Calculated Resource Adequacy Risk Measures LOLE & LOLH from All Resource Adequacy Analyses

	Scenario	Loss of Load Expectation (LOLE), Days / Year	Loss of Load Hours (LOLH), Hours / Year
	Base Case	36.2	154.2
	Force Majeure Scenario	66.7	339.9
Unavailability of existing resources	Unavailability of emergency generation (TM generators)	120.4	694.9
	Unavailability of Costa Sur 6	106.4	555.3
	Unavailability of AES	140.4	860.0
Addition of standalone solar	Non-tranche + Tranche 1 solar-only projects	34.3	124.3
	Additional distributed solar PV (DG)	35.6	147.0
Addition of Standalone BESS resources	Tranche 1 BESS-onlv projects	8.1	33.3
	ASAP BESS project	9.5	45.3
	ASAP BESS project (Q4 FY 2025 only)	30.2	130.2
	Genera's BESS projects	5.6	22.0
	LUMA's 4x25 BESS project	23.4	105.4
	Tranche 1 + ASAP + Genera + LUMA's 4x25 BESS-only projects	0.1	0.2
Addition of solar paired BESS resources	Tranche 1 projects (555 MW solar + 350 MW 4-hr BESS)	14.1	49.5
	Tranche 1 (Solar + BESS) + ASAP projects	3.1	8.5
	Tranche 1 (Solar + BESS) + Genera BESS projects	2.3	6.0
	Tranche 1 (Solar + BESS) + LUMA's 4x25 BESS projects	7.6	24.8
	Tranche 1 (Solar + BESS) + ASAP + Genera + LUMA's 4x25 projects	0.2	0.5
Addition of other resources	850 MW of 'Perfect Capacity'	0.1	0.3
	New Flexible Thermal Resource	9.4	33.0
	Demand Response Resources	32.2	135.8
Load affected sensitivities	Load sensitivity (+10% load increase)	96.9	501.3
	Load sensitivity (-10% load decrease)	8.8	32.0
	Addition of Electric Vehicles Load (6,000 EV's)	36.5	155.9
	Industry Benchmark Target	0.1	—

3.3.7 Achieving U.S. Electric Utility Industry Resource Adequacy

As noted elsewhere in this report, the U.S. electric utility industry has established a planning standard in resource adequacy such that loss of load expectation (LOLE) should be no more than 0.1 days per year. This section of the report provides perspective on what set of changes to the Puerto Rico electricity system would improve resource adequacy beyond the Base Case estimated LOLE of 36.2 days/year to achieve a target LOLE of 0.1 days/year.

Two of the above-referenced sensitivity analyses produced results in which over 90% of the hourly simulations resulted in 0 days/year of load loss events, thus implying that the target 0.1 days/year LOLE would be achieved:

- **Perfect Capacity Analysis**. As described above, Monte Carlo simulations of resource adequacy discovered that 850 MW of “perfect” capacity in Puerto Rico – 850 MW of new capacity with 100% availability, or 850 MW of demand reduction in every hour of the year – would yield an estimated LOLE of 0.1 days/year.

- **Tranche 1 + ASAP + Genera + LUMA 4x25 standalone BESS**. The addition of 1240 MW of energy storage, even without the addition of any new electricity generating capacity, was found to also yield an estimated LOLE of 0.1 days/year.

In conclusion, U.S. mainland levels of resource adequacy – implying an associated 0.1 days/year LOLE – is estimated to be achievable in Puerto Rico if either (1) electricity demand were to be reduced by 850 MW in every hour of the year, (2) new thermal power plant capacity of approximately 1,000 MW (resulting in “perfect” capacity of 850 MW) were added to the grid, or (3) 1,240 MW of BESS resources were added to the grid.

Appendix A. Findings from Sensitivity Analyses

This appendix presents details on the results from sensitivity analyses conducted in this resource adequacy assessment.

A.1 Unavailability of Existing Thermal Resources

This section contains the analytic results of resource adequacy assessment from the following sensitivity analyses in which different assumptions are made about the availability of fossil generation resources in Puerto Rico:

- Unavailability of emergency generation (TM generators)
- Unavailability of Costa Sur 6
- Unavailability of AES powerplant

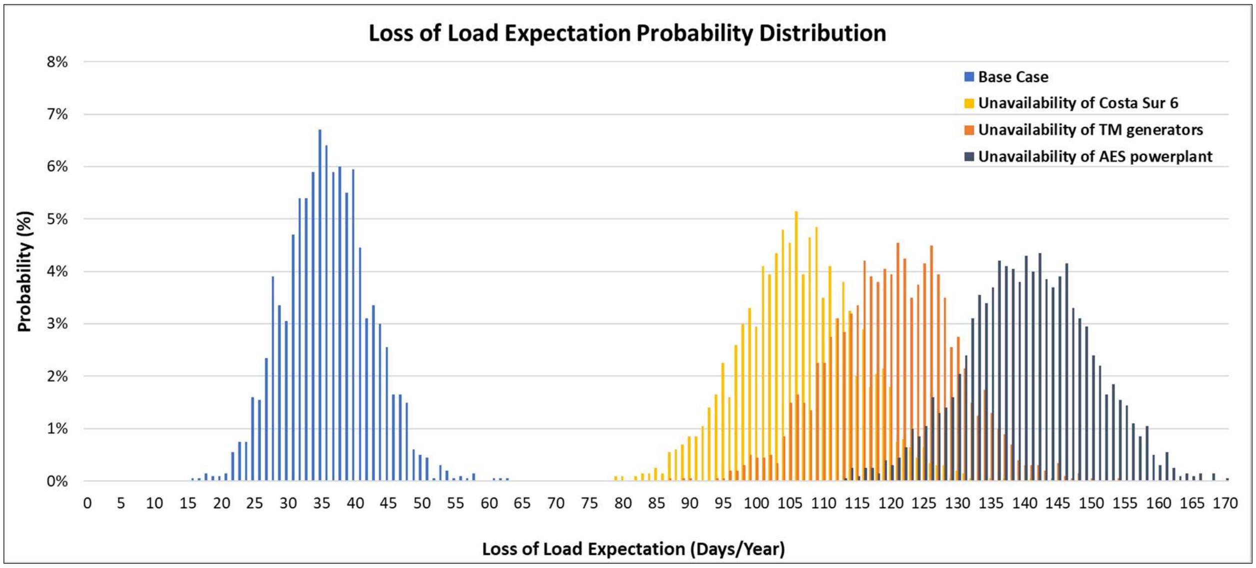
When compared with the Base Case, any one of these three sensitivities involving the prolonged unavailability of existing thermal resources significantly worsens resource adequacy. As shown in Table A-1below, unavailability of the TM generators produces an increase of 233% on the forecasted LOLE, unavailability of Costa Sur 6 increases LOLE by 194%, and the unavailability of AES powerplant increases LOLE by 288%.

Table A-1: Calculated Resource Adequacy Measures Associated with Unavailability of Existing Thermal Resources

Sensitivity Analysis	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Base Case	36.2 Days / Year	154.2 Hours / Year
Unavailability of TM generators	120.4 Days / Year	694.9 Hours / Year
Unavailability of Costa Sur 6	106.4 Days / Year	555.3 Hours / Year
Unavailability of AES powerplant	140.4 Days / Year	860.0 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

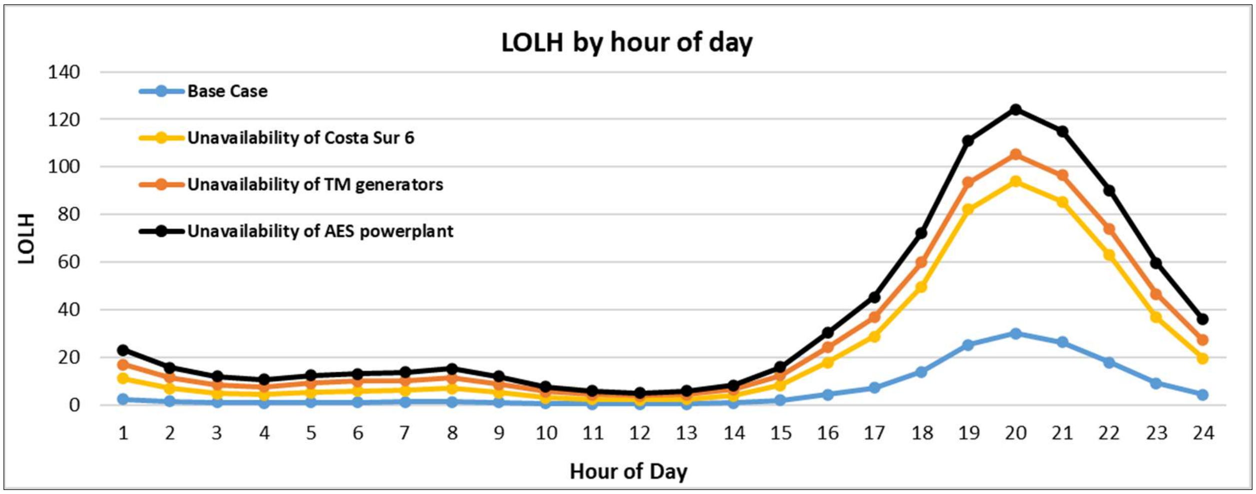
Figure A-1 shows how the probability distribution of outcomes for LOLE significantly worsens relative to the Base Case under each of these three sensitivity analyses.

Figure A-1: Comparison of Loss of Load Expectation Probability Distributions Associated with Unavailability of Existing Thermal Resources



Meanwhile, Figure A-2 indicates how much LOLH increases relative to the Base Case for each of these three sensitivity analyses.

Figure A-2: Comparison of Loss of Load Hourly Associated With Unavailability of Existing Thermal Resources



Of the three sensitivity analyses undertaken to assess the incremental impact of prolonged unavailability of existing thermal generation capacity, the loss of the AES powerplant would have the biggest negative impact. This is because the AES powerplant is one of the biggest contributors to electricity generation supply in Puerto Rico – being both one of the largest power plant units on the island and with among the lowest forced outage rates – so its extended unavailability would be among the worst possible single failures that could possibly harm Puerto Rico electricity system reliability.

A.2 Addition of Standalone Solar Resources

This section presents resource adequacy modeling results from the following sensitivity analyses that involve the addition of stand-alone solar resources (i.e., without energy storage):

- Non-tranche + Tranche 1 Projects
- Additional Distributed Solar PV (DG)

Additions of solar generating resources are likely to occur in two ways: (1) large-scale projects developed by Independent Power Producers and connected to Puerto Rico's transmission grid for delivery to retail customers by LUMA, and (2) small-scale distributed solar PV installations principally located on residential rooftops.

As seen in Table A-2 below, relative to the Base Case, the addition of standalone solar resources improves LOLH somewhat, but has relatively little impact on LOLE.

Table A-2: Calculated Resource Adequacy Risk Measures Associated With Standalone Solar PV Addition Sensitivities

Sensitivity Analysis	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
Base Case	36.2 Days / Year	154.2 Hours / Year
Non-Tranche + Tranche 1 Solar only projects	34.3 Days / Year	124.3 Hours / Year
Additional distributed solar PV (DG)	35.6 Days / Year	147.0 Hours / Year
Industry Benchmark Target	0.1 Days / Year	—

Because solar resources can only generate electricity during daytime hours, standalone solar resources (i.e., without energy storage) do help reduce LOLH during daytime hours but contribute virtually nothing during evening hours from 6pm to 10pm when system load peaks, which is when load-shed events are most likely (i.e., when LOLE is highest).

In short, standalone additions of solar energy produce only small improvements in Puerto Rico's resource adequacy. This is well-illustrated by calculating the Effective Load Carrying Capacity (ELCC) of standalone PV in Puerto Rico, which as shown in Table A-3 to be less than 2%.

Table A-3: Calculated ELCC Metrics Standalone Solar PV Addition Sensitivities

Sensitivity Analysis	Perfect Capacity Equivalent MW	ELCC (%)
755 MW Solar PV	12	1.52%
1,755 MW Solar PV	20	1.14%
2,755 MW Solar PV	24	0.85%

An ELCC of less than 2% means that each 100 MW of PV addition (without energy storage) produces the equivalent improvement in resource adequacy of less than 2 MW of "perfect capacity". Moreover, note from Table A-3 that the ELCC of standalone PV declines as more PV is added to the system, indicating that the marginal benefit of adding another MW of solar to the Puerto Rico electricity grid declines as the installed base of PV increases.

The limited improvement in resource adequacy associated with adding standalone solar PV to the system is a function of when solar PV power plants generate electricity and when the Puerto Rico electricity system is at greatest risk for loss of load. During the middle of the day, solar PV can contribute substantially towards meeting system load, thus mitigating the risk of load-loss if a large thermal generator were to fail during daylight hours. However, during the evening (after the sun has set) when electricity demands are highest, solar PV is not able to contribute much towards meeting system load.

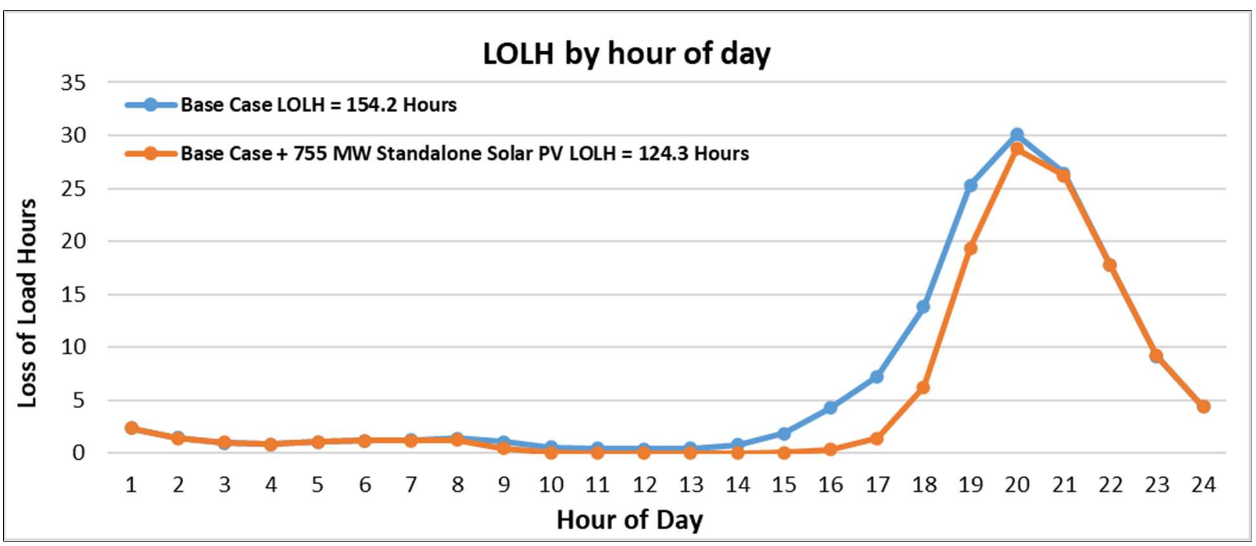
Each of the two standalone solar sensitivity analyses is presented in greater detail below.

A.2.1 Non-Tranche + Tranche 1 Projects

This sensitivity considers the addition of approximately 755 MW of solar energy to the Base Case. Of the 755 MW of additions, 555 MW are associated with Tranche 1 solar projects, while 200 MW are attributed to non-tranche solar projects (140 MW from Ciro One and 60 MW from Xzerta). In comparison to the Resource Adequacy analysis previously produced by LUMA for FY2024, the amount of solar capacity assumed to be included Tranche 1 decreased by approximately 290 MW (from 845 MW to 555 MW) due to project withdrawals. The 755 MW of solar PV added to the Base Case decreases LOLE from 36.2 days/year to 34.3 days/year (a 5% improvement) and decreases LOLH from 154.2 hours/year to 124.3 hours/year (a 19% improvement).

Figure A-3 illustrates the impact on LOLH for each hour of the day, showing how additional solar PV resources reduce LOLH in late afternoon hours (before peak demand) but not in the evening (during peak demand).

Figure A-3: Comparison of Loss of Load Hours by Hour of Day - Utility-Scale PV Addition Sensitivity



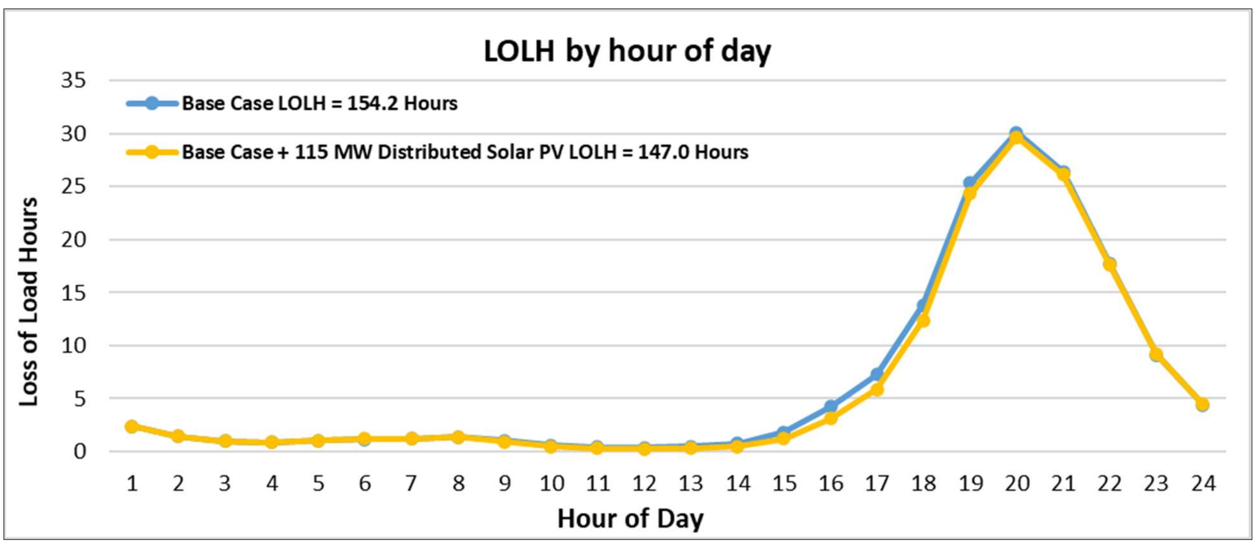
A.2.2 Adding 115 MW of Distributed Solar PV

This sensitivity analysis was conducted to assess the potential resource adequacy implications of adding approximately 115 MW of distributed solar PV generation in Puerto Rico.

Distributed solar PV is mainly composed of rooftop solar PV installations on residential and commercial rooftops. Compared to utility-scale solar PV, in which site location and PV module array orientation can be nearly perfectly optimized for maximum electricity production, it is difficult to perfectly optimize the location and module orientation of distributed solar PV because the orientation of the building and any nearby shading from trees or other buildings may result in less-than-optimal electricity generation. As a result, distributed solar PV systems will on average exhibit lower capacity factors than utility-scale PV installations. To develop appropriate assumptions for distributed solar PV hourly output levels, the utility-scale solar PV generation hourly generation profile (obtained from the existing fleet of IPP solar projects already installed in Puerto Rico) was reduced by 15% in each hour.

Relative to the Base Case, the addition of 115 MW of distributed solar PV decreases LOLE marginally, from 36.2 days/year to 35.6 days/year (a 2% improvement) and decreases LOLH from 154.2 hours/year to 147.0 hours/year (a 5% improvement). The impact of this sensitivity analysis on LOLE is too small to appear visually in an illustration. Figure A-4 below illustrates the small impact of this sensitivity analysis on LOLH for each hour of the day.

Figure A-4: Comparison of Loss of Load Hours by Hour
Distributed Solar PV Sensitivity



A.3 Addition of Standalone BESS Resources

This section presents resource adequacy modeling results from the following sensitivity analyses that involve the addition of battery energy storage systems (BESS) relative to the Base Case:

- Addition of Tranche-1 BESS only projects (350 MW 4-hr)
- Addition of ASAP BESS project (360 MW 4-hr)

  - Available for Full FY 2025
  - Available only for Q4 of FY 2025
- Addition of Genera's BESS projects (430 MW 4-hr)
- Addition of LUMA 4X25 BESS projects (100 MW 4-hr)
- Addition of Tranche-1 BESS only + ASAP + Genera's + LUMA's 4X25 BESS projects (1240 MW 4-hr) Standalone BESS

Note that BESS resources do not generate electricity, and hence are not supply resources. Rather, BESS resources store electricity produced by some other generation resource, to be later dispatched into the grid as directed by the system operator. For these sensitivity analyses, it is assumed that the standalone BESS resources will be charged from the Puerto Rico grid based on the availability of capacity reserves. As a result, BESS resources improve LOLE and LOLH by charging from the grid at hours when system load is lower and available capacity is higher, and then discharging during peak load hours when system load is higher and available capacity is lower.

For the standalone BESS sensitivities, the round-trip efficiency of the BESS projects is assumed to be 85%, meaning that 15% of all electricity purchased from the grid during battery charging is lost. Given that all BESS resources are assumed to have a 4-hour duration, dispatch of the BESS is modeled such that discharge occurs between 18:00 and 22:00 hours to help meet peak load, since most load-shed events occur at peak demand hours. Meanwhile, the charging time for all BESS projects is set to take place over the 7 hours between 2:00 am and 9:00 am, when system load is the lowest.

Except for the ASAP sensitivity, the effective capacity range of the BESS is limited between 20% and 80%, as battery performance has generally shown to degrade more quickly when they are cycled between fully charged and fully depleted states. The ASAP sensitivity analysis does not assume such limitations, since the ASAP program currently under development allows for the full capacity range of batteries to be utilized.

Figures A-5 and A-6 below show assumptions about the average state of charge by hour of the day for standalone BESS resources in all BESS-related sensitivity analyses. As shown, BESS resources are assumed to primarily charge overnight between 2 am and 9 am, and then start discharging at 6 p.m. to help the system during the evening peak.

Figure A-5: Standalone BESS Average State of Charge by Hour for Tranche-1 BESS, Genera's BESS, and LUMA's 4X25 BESS Projects

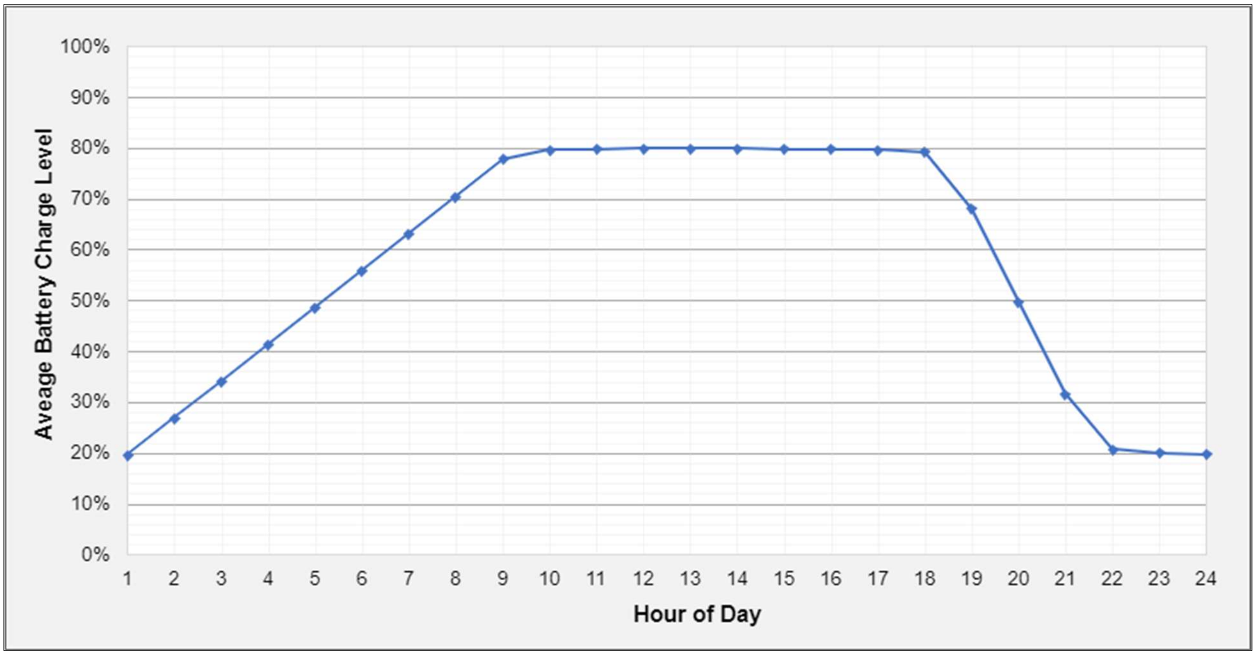
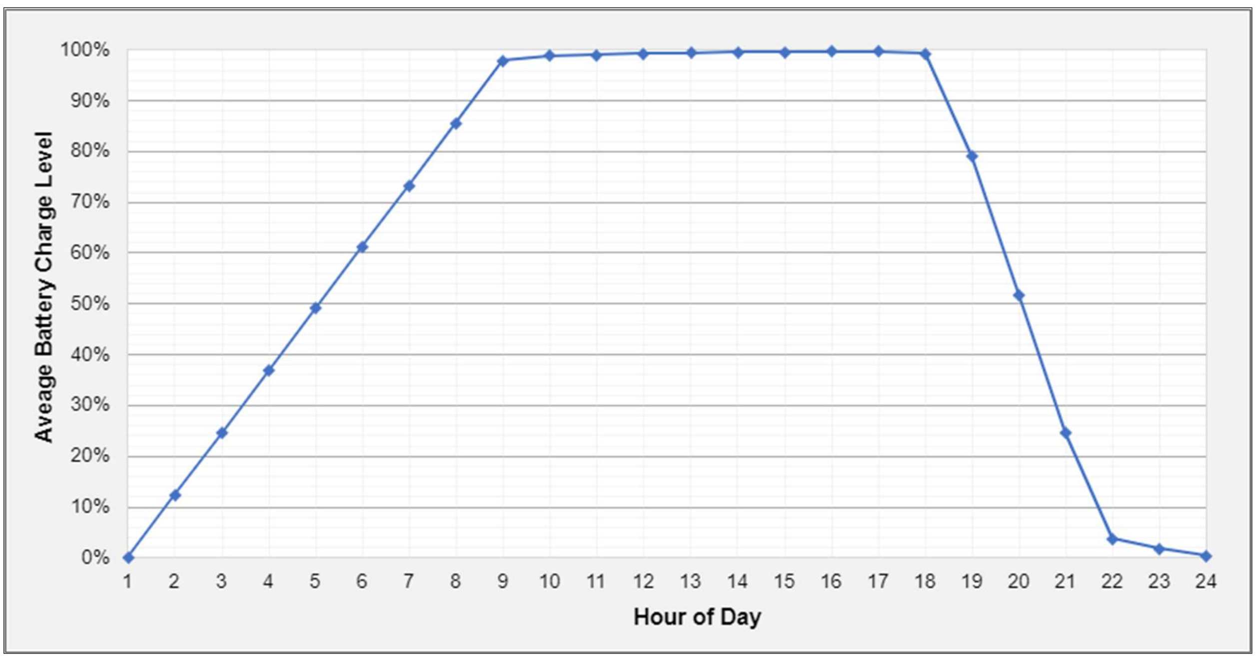


Figure A-6: Standalone BESS Average State of Charge by Hour for ASAP BESS Project



Whenever modeled system load is greater than total system available capacity, the model forces the BESS resources to inject available energy to help meet demand. If the shortfall in available system capacity is greater than what the BESS can inject at that hour, the BESS resources inject what they are able to minimize the MW shortfall.

In contrast to solar-paired BESS projects (whose sensitivity analyses are discussed in the next section), standalone BESS projects are assumed to charge from the grid, capturing surplus energy during times when available capacity is high and energy demand is low (i.e., nighttime). Since standalone BESS can be fully charged earlier in the day than solar-paired BESS, standalone BESS can be dispatched to help mitigate emergency shortfall situations that occur earlier in the day, when a solar-paired BESS might otherwise not yet be fully charged. In contrast, because standalone BESS charges from energy from generating resources that are operating at that time, if standalone BESS is charging during the early morning, it is primarily charging from thermal generators, not renewable generators.

Additionally, if standalone BESS resources are mostly charged before the sun rises, then these resources will not be able to exploit otherwise excess solar electricity generation, and thus will not be able to be used as a tool to help mitigate the potential curtailment of solar power plant output. Because of these considerations, LUMA recommends both standalone and solar-paired BESS be considered as potential candidate resources for further analysis in the future resource planning activities, especially as more and more PV is installed in Puerto Rico.

Table A-4 below summarizes resource adequacy modeling results from the standalone BESS sensitivity analyses, along with the Base Case results for comparison.

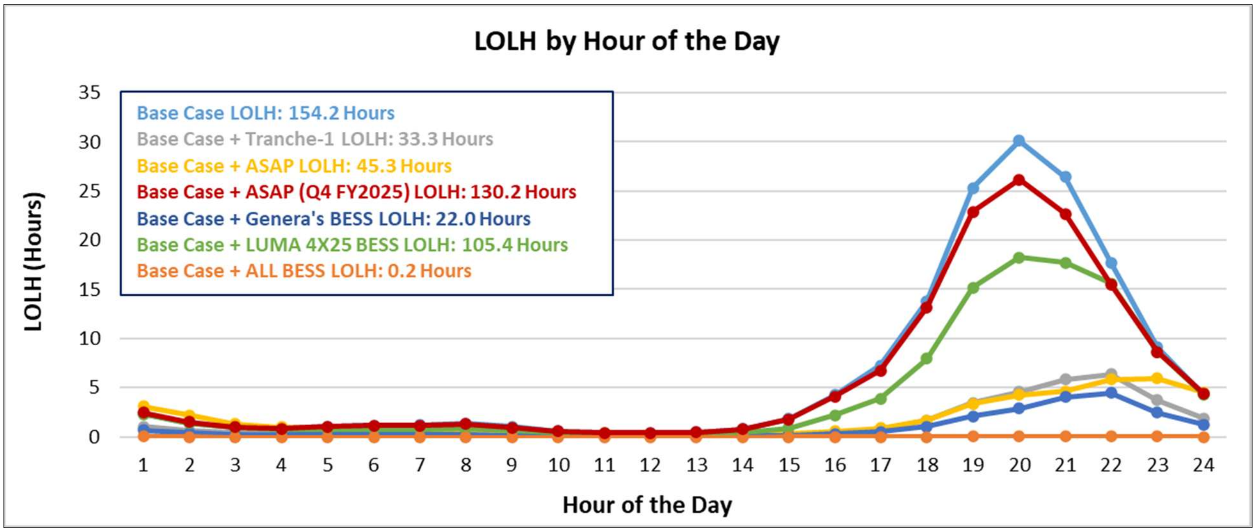
Table A-4: Calculated Resource Adequacy Risk Measures Associated With Standalone BESS Addition Sensitivities

	Sensitivity Analysis	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
	Base Case	36.2 Days / Year	154.2 Hours / Year
Base Case +	Tranche-1 BESS only (350 MW 4-hr)	8.1 Days / Year	33.3 Hours / Year
Base Case +	ASAP BESS project (360MW 4-hr)	9.5 Days / Year	45.3 Hours / Year
Base Case +	ASAP BESS project (360 MW 4-hr) (Q4 FY 2025 only)	30.2 Days / Year	130.2 Hours / Year
Base Case +	Genera’s BESS projects (430 MW 4-hr)	5.6 Days / Year	22.0 Hours / Year
Base Case +	LUMA 4X25 BESS projects (100 MW 4-hr)	23.4 Days / Year	105.4 Hours / Year
Base Case +	Tranche-1 + ASAP + Genera + LUMA 4X25 BESS only projects (1240 MW 4-hr)	0.1 Days / Year	0.2 Hours / Year
	Industry Benchmark Target	0.1 Days / Year	—

Table A-4 shows that the addition of standalone BESS resources results in meaningful improvements to both LOLE and LOLH in each sensitivity analysis. This is because standalone BESS resources can contribute to system capacity nearly all times of the day, with the only limitation being the state of charge of a BESS project. Given that the majority of the observed LOLH in the expected case scenario occurred between 6 p.m. and 11 p.m., the addition of standalone BESS resources has a strong positive impact on system resource adequacy due to the ability of BESS resources to support the system at night.

Figure A-7 below shows the average LOLH for all the simulations for the Base Case and all standalone BESS sensitivity analyses. As shown, standalone BESS resources reduce the incidence of LOLH in all hours.

Figure A-7: Comparison of Loss of Load Hours by Hour of Day Associated With Standalone BESS Addition Sensitivities



The positive impact of BESS resources on resource adequacy is reflected by the high ELCC factors associated with BESS resources. Unlike standalone PV resources, BESS resources can (if charged) supply electricity during all hours of the day, including during the evening when system load is highest and when the risk of load-shed is also highest. Whereas standalone PV has an ELCC of less than 2% as shown in Table A-3, Table A-5 shows that the ELCC of small amounts of incremental standalone BESS is nearly 100%. The ELCC declines only slowly as more standalone BESS resources are added, such that 1200 MW of new BESS resources still has an ELCC of roughly 70%.

Table A-5: Calculated ELCC Metrics Standalone BESS Sensitivities

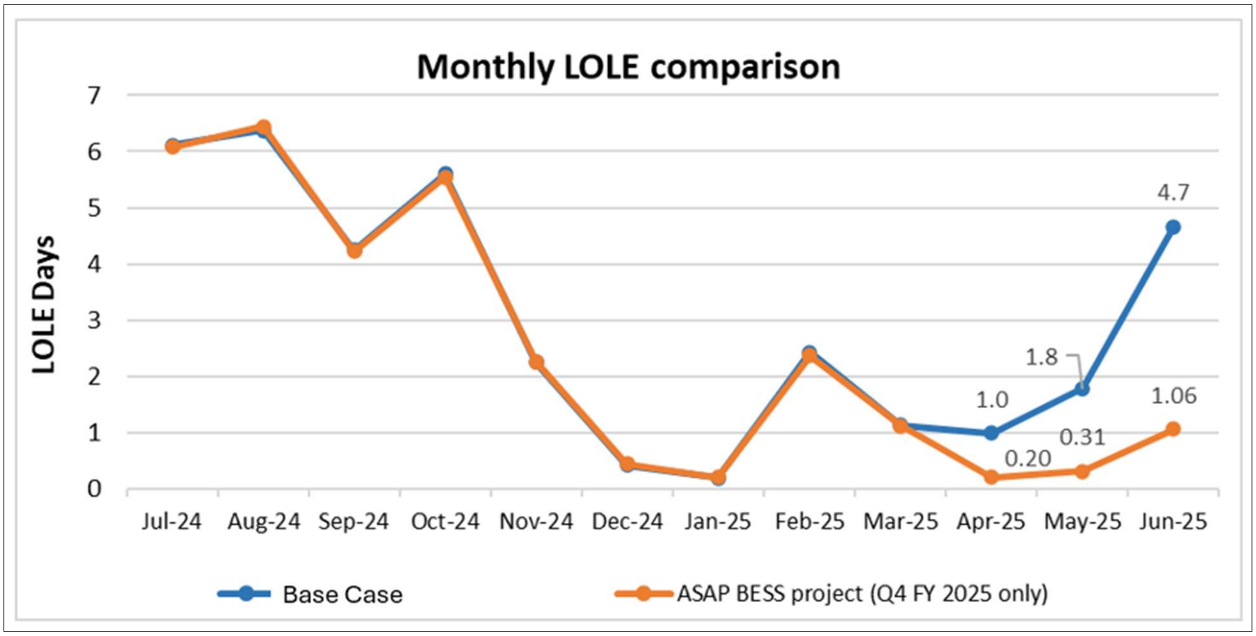
Sensitivity Analysis	Perfect Capacity Equivalent MW	ELCC (%)
100 MW BESS	90	90%
350 MW BESS	281	80%
430 MW BESS	340	79%
1240 MW of BESS	850	69%

The results from the sensitivity analyses related to the ASAP project merit additional discussion.

Even though the ASAP sensitivity involves the addition of 10 MW more BESS resources (360 MW) than the Tranche 1 sensitivity (350 MW), the ASAP sensitivity yields higher LOLE and LOLH values. This is because the BESS resources in the ASAP sensitivity are assumed to be discharged fully every evening so that they have zero capacity available to assist with emergency events that occur between 11 pm and 2 am, whereas the BESS resources in the Tranche 1 sensitivity are constrained by assumption to retain 20% of rated capacity remaining in reserve to use in emergencies during the time window between 11 pm to 2 am.

Additionally, because the ASAP program is scheduled to come on-line in CY 2025, a separate sensitivity analysis was undertaken to assess the implications on resource adequacy if the ASAP BESS resources were available to the Puerto Rico grid only during the fourth quarter of FY 2025 (rather than all of FY 2025). As Figure A-8 indicates, the addition of ASAP BESS resources in the spring of 2025 reduces expected LOLE in June 2025 by over 75% (from 4.7 to 1.06).

Figure A-8: Reduction in LOLE if ASAP BESS Resources Online By April 2025



A.4 Addition of Solar-Paired BESS Resources

This section presents resource adequacy modeling results from the following sensitivity analyses that involve the addition of battery energy storage systems (BESS) along with new solar generation capacity:

- Addition of Tranche 1 Solar + BESS projects
- Addition of Tranche 1 (Solar + BESS) + ASAP BESS projects
- Addition of Tranche 1 (Solar + BESS) + Genera's BESS projects
- Addition of Tranche 1 (Solar + BESS) + LUMA's 4x25 BESS projects
- Addition of Tranche 1 (Solar + BESS) + ASAP + Genera + LUMA 4X25 projects

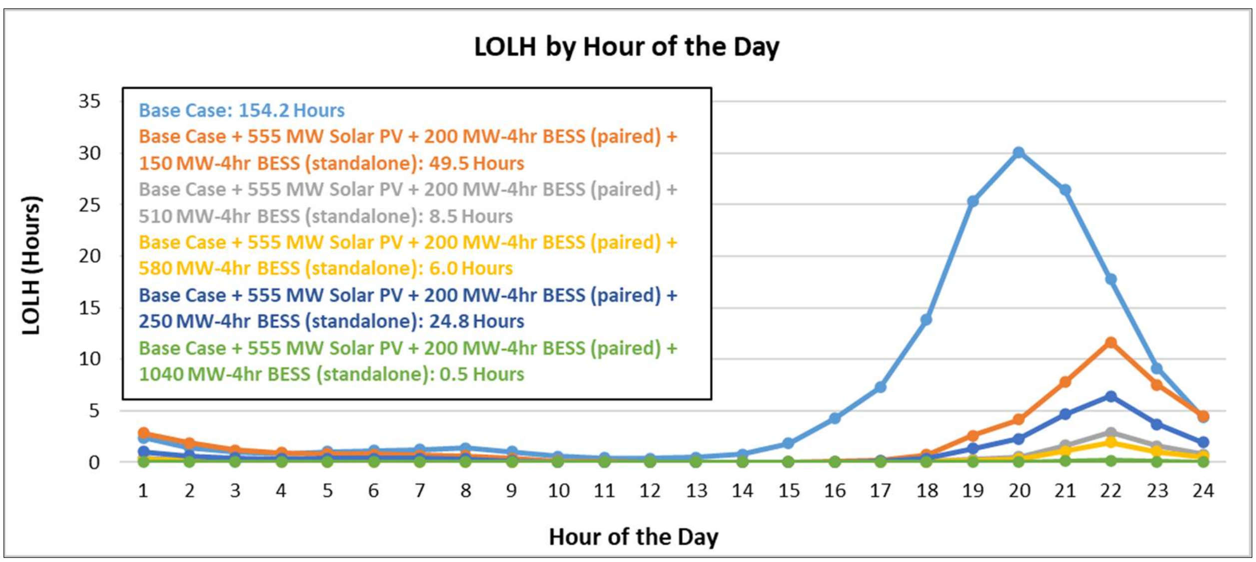
Table A-6 presents estimated LOLE and LOLH for these sensitivity analyses, indicating improved resource adequacy in all instances when compared to the Base Case.

Table A-6: Calculated Resource Adequacy Risk Measures Associated With Solar-Paired BESS Addition Sensitivities

	Sensitivity Analysis	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
	Base Case	36.2 Days / Year	154.2 Hours / Year
Base Case +	Tranche 1 (555 MW Solar + 350 MW BESS)	14.1 Days / Year	49.5 Hours / Year
	Tranche 1 (555 MW Solar + 350 MW BESS) + 360 MW BESS	3.1 Days / Year	8.5 Hours / Year
	Tranche 1 (555 MW Solar + 350 MW BESS) + 430 MW BESS	2.3 Days / Year	6.0 Hours / Year
	Tranche 1 (555 MW Solar + 350 MW BESS) + 100 MW BESS	7.6 Days / Year	24.8 Hours / Year
	Tranche 1 (555 MW Solar + 350 MW BESS) + 890 MW BESS	0.2 Days / Year	0.5 Hours / Year
	Industry Benchmark Target	0.1 Days / Year	—

Figure A-9 below shows the average LOLH for the Base Case and for all solar-paired BESS sensitivity analyses. As shown, standalone BESS resources reduce the incidence of LOLH in all hours.

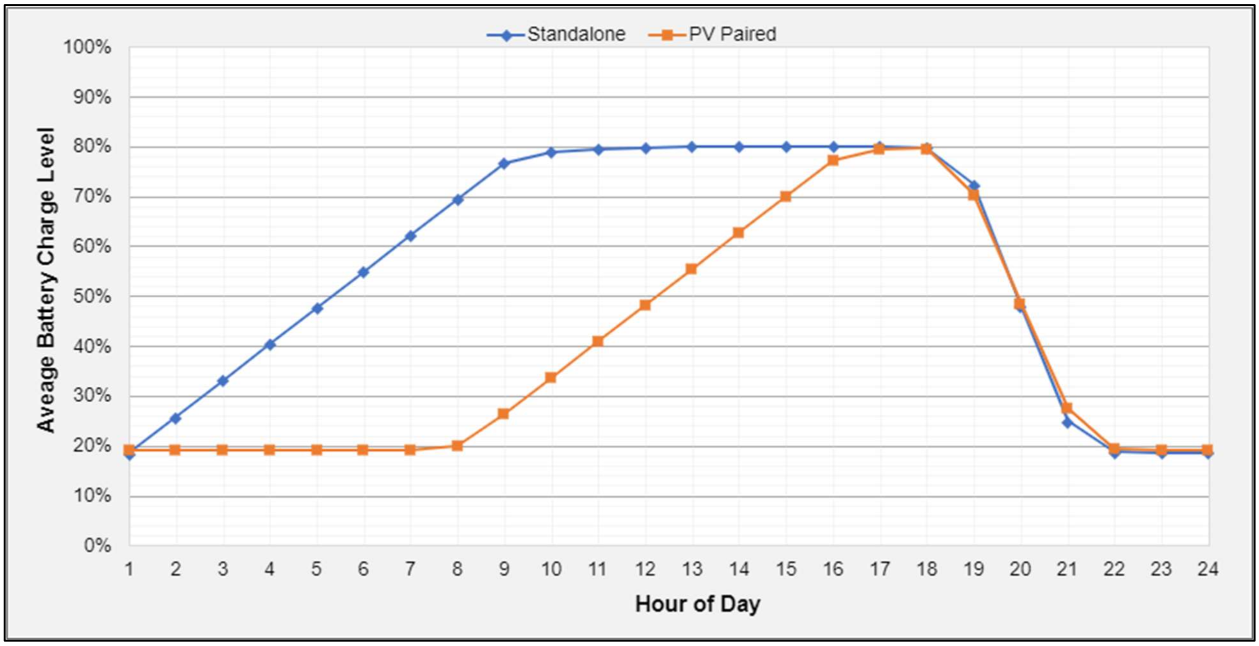
Figure A-9: Comparison of Loss of Load Hours by Hour of Day Associated With Solar-Paired BESS Addition Sensitivities



By assumption, solar-paired BESS resources are expected to recharge from the solar energy generation sources with which the BESS resources are paired. An implication of this assumption is that solar-paired BESS resources do <u>not</u> start recharging to prepare for the daily dispatch cycle until after the sun rises.

Figure A-10 shows the comparison of average state of charge by hour of the day for the solar-paired BESS and the standalone BESS. As shown, the solar-paired BESS begins to charge as the sun rises and is assumed to be fully charged by the time of evening load peak. Both standalone BESS resources and solar-paired BESS resources start discharging at 6 p.m. as the sun sets to support the electricity system during the evening peak.

Figure A-10: Solar-Paired BESS & Standalone BESS Average State of Charge by Hour



The interaction between the solar PV component and the BESS component of a solar-paired BESS resource – specifically, the implication of solar generation availability on the timing and magnitude of BESS charging – reveals itself in the calculated Effective Load Carrying Capacity (ELCC) of solar-paired BESS resources.

Table A-7 shows that the ELCC of solar-paired BESS is higher than standalone PV, but not as high as standalone BESS. This is because standalone BESS resources have the flexibility to charge at any hour that they are not discharging energy, whereas solar-paired BESS is assumed to only charge during daytime hours, thus leaving solar-paired BESS with less availability to supply energy to the grid than standalone BESS.

Table A-7: Calculated Equivalent Perfect Capacity – Solar-Paired BESS

Sensitivity Analysis	Perfect Capacity Equivalent MW	ELCC (%)
555 MW Solar PV + 350 MW BESS	255	29%
1,555 MW Solar PV + 350 MW BESS	295	15%
555 MW Solar PV + 700 MW BESS	375	30%
1,555 MW Solar PV + 700 MW BESS	450	20%

To confirm the validity of the results of the solar-paired BESS sensitivity analyses, LUMA utilized the PLEXOS production cost model to simulate the daily dispatch of Puerto Rico's generators both with and without the Tranche 1 solar PV and BESS projects.

Figure A-11 shows average daily dispatch under Base Case conditions, while Figure A-12 shows average daily dispatch assuming the Tranche 1 renewable and storage projects operating (totaling 555 MW of solar PV and 350 MW of 4-hour energy storage).

Figure A-11: Average Generator Dispatch in Base Case

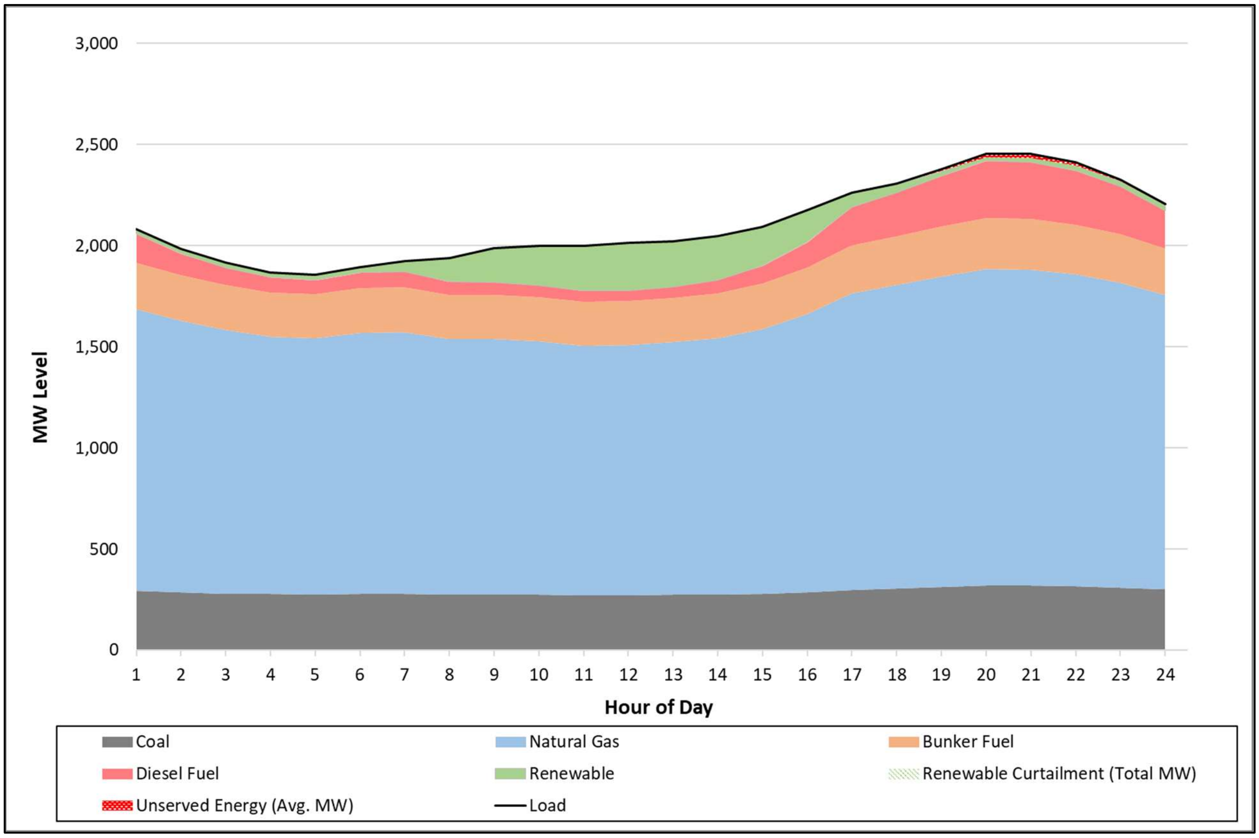
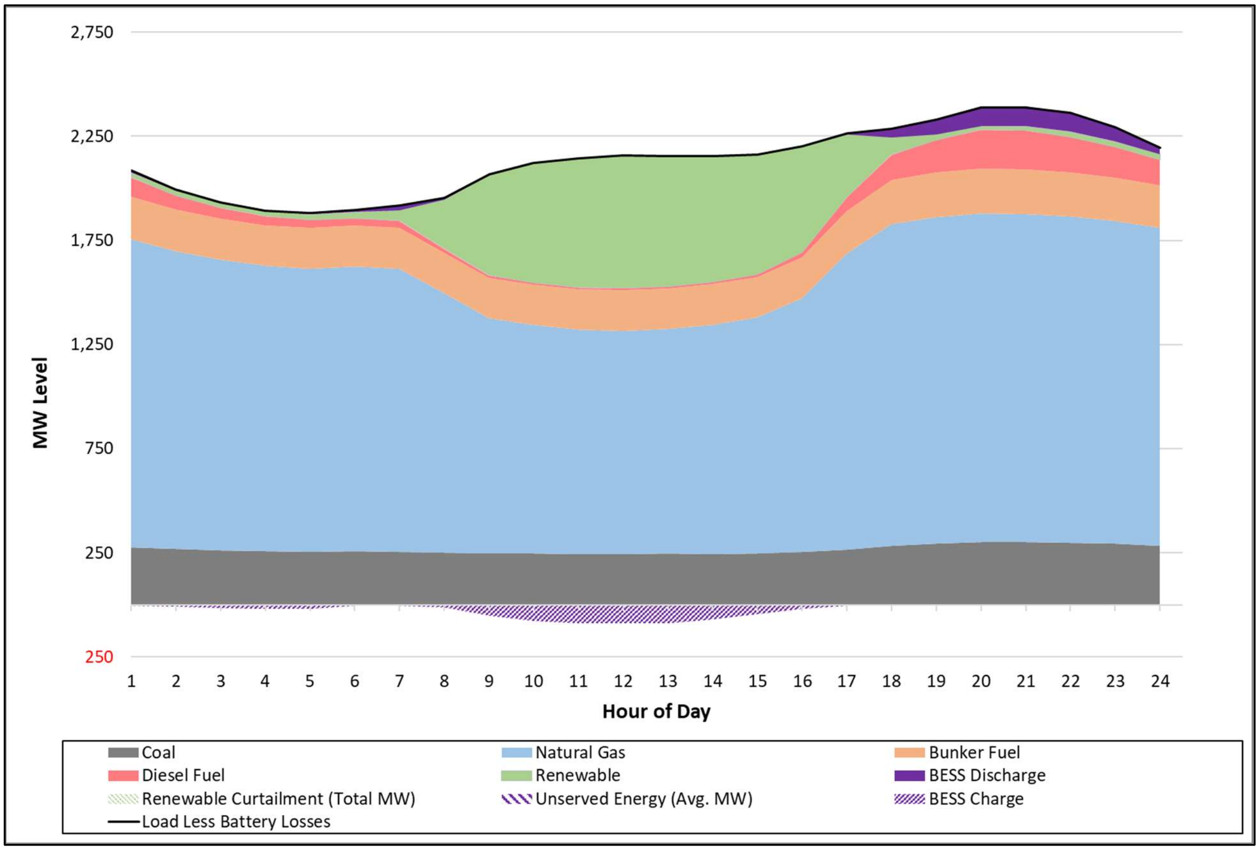


Figure A-12: Average Generator Dispatch for Tranche 1 Solar and Energy Storage Sensitivity Analysis



As can be observed by comparing Figures A-11 and A-12, the addition of Tranche 1 Solar and Energy Storage to the Base Case results in a significant increase in the amount of renewable generation during the middle of the day. For the electric system to make room for this additional generation, the thermal power plants are required to turn down during the middle of the day. Importantly, the generators that are primarily able to do so are those that consume natural gas: generators that consume bunker fuel cannot be turned down much further since they are already near or at their minimum stable operating levels, while the one power plant in Puerto Rico that consumes coal (AES) is the lowest cost generator on the island and thus is rarely turned down for economic reasons. Since most if not all thermal generators are needed to meet load during the evening (when solar generation falls to zero), they cannot be completely turned off during the middle of the day because most would not be able to start back up in time to meet the evening peak load.

The addition of Tranche 1 PV results in a need for the existing thermal generators in Puerto Rico to significantly reduce generation during the middle of the day, then quickly increase generation for the evening – a phenomenon known as generator cycling. One consequence of increased cycling is additional wear on power plant equipment, which results in more frequent planned outages and potentially a higher risk of forced outages. From a resource adequacy perspective, while modelling the addition of solar-paired energy storage was found to significantly improve system resource adequacy, the negative impact of thermal generator cycling on planned outage frequency and forced outage rate was not considered in the resource adequacy analysis. Any increases in thermal generator planned outage frequency or forced outage rates due to increased cycling will negatively affect system resource adequacy, although this negative impact is unlikely to outweigh the positive impacts on resource adequacy produced by the addition of solar-paired BESS resources.

A.5 Addition of Other Resources

This section presents resource adequacy modeling results from the following sensitivity analyses that involve the addition of resources other than new solar generation or new BESS projects to help meet system load:

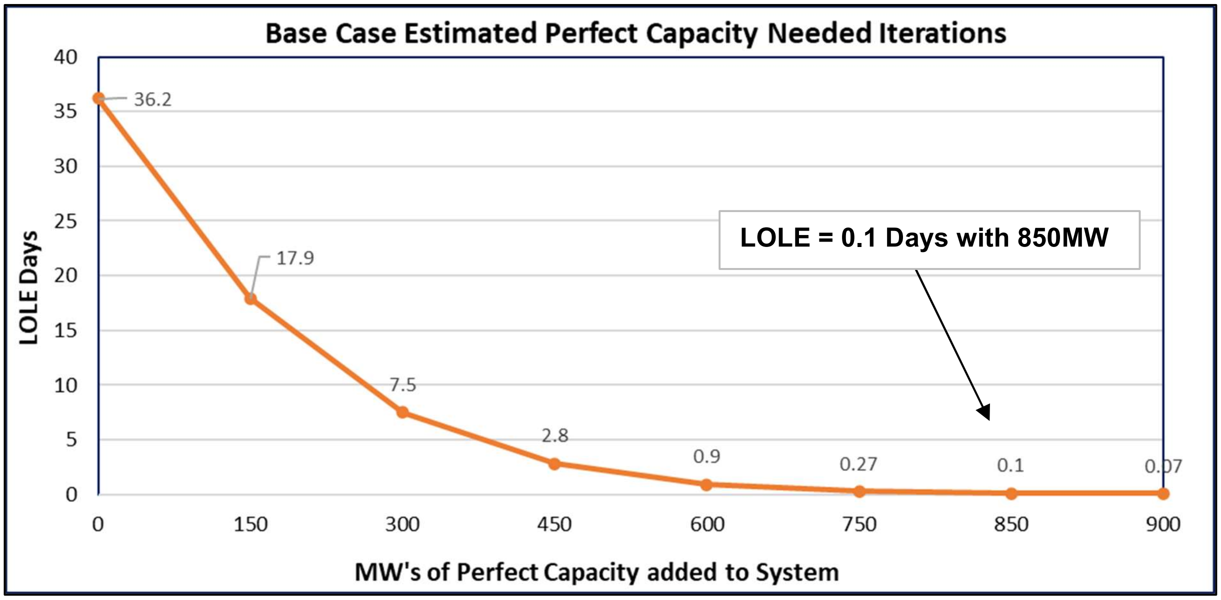
- Estimated Perfect Capacity Need
- Addition of New 300 MW Combined Cycle (CC) Thermal Resource
- Addition of 25 MW of Demand Response (DR) Resources

A.5.1 Estimated Perfect Capacity Need

A sensitivity analysis was performed to determine how much additional “perfect capacity” would need to be added to the Puerto Rico electricity system under Base Case assumptions to achieve the US industry benchmark LOLE target of 0.10 days/year. This was accomplished by adding various amounts of perfect capacity in the resource modeling analyses so that the resulting LOLE would equal 0.10 days/year. Through iterative analysis, it was found that the amount of perfect capacity that resulted in 0.10 days/year LOLE was 850 MW.

Figure A-13 shows the iterative process for the calculation of the amount of perfect capacity needed to reach 0.10 LOLE days/year. Perfect capacity additions were increased in 150 MW increments between iterations. Because the iteration with 900MW resulted an estimate of LOLE days below 0.1 days/year, an iteration with 850MW was subsequently performed and found to produce the desired result of 0.1 LOLE days/year.

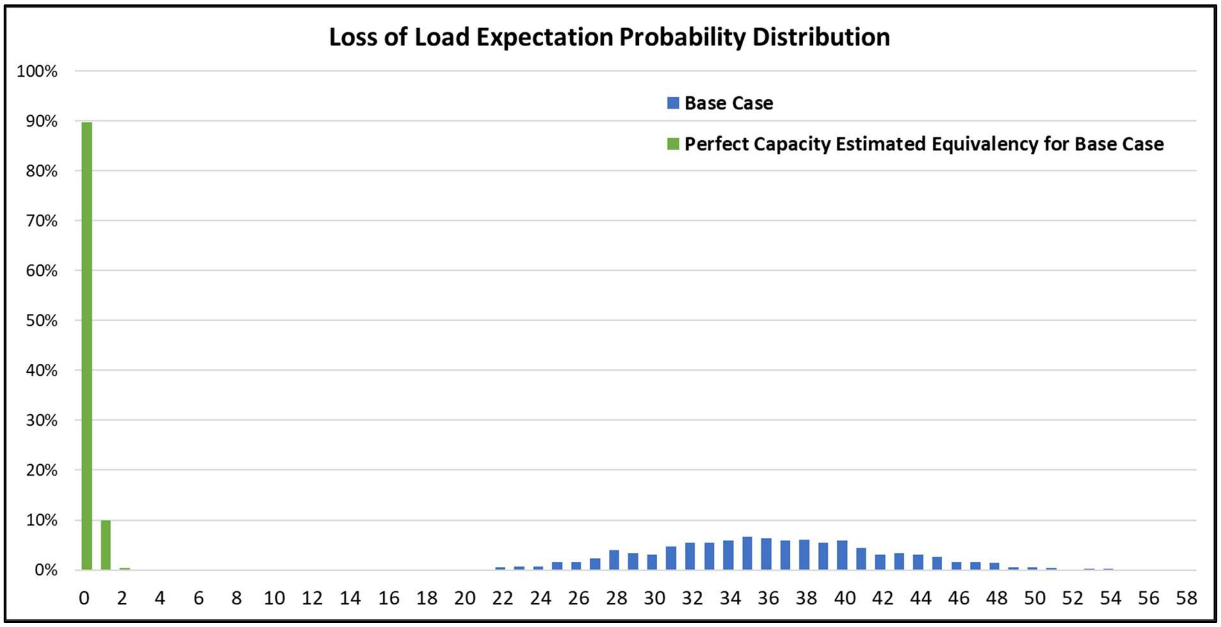
Figure A-13: Loss of Load Expectation with Incremental Amounts of Perfect Capacity



Given that no generation technology can operate as a perfect generator, the actual amount of new capacity additions required for the Puerto Rico electricity system to meet a 0.10 days/year LOLE target would be somewhat higher than the 850 MW identified above.

Figure A-14 compares the distribution of LOLE (for the 2,000 simulations performed) between the Base Case scenario and the sensitivity analysis in which 850 MW of perfect capacity is added. Figure A-12 shows that 90% of the simulations resulted in 0 days LOLE, with the remaining 10% of the simulations resulting in 1 day LOLE, thus leading to an average of 0.1 days/year LOLE.

Figure A-14: Comparison of Loss of Load Expectation
Perfect Capacity Sensitivity vs Base Case



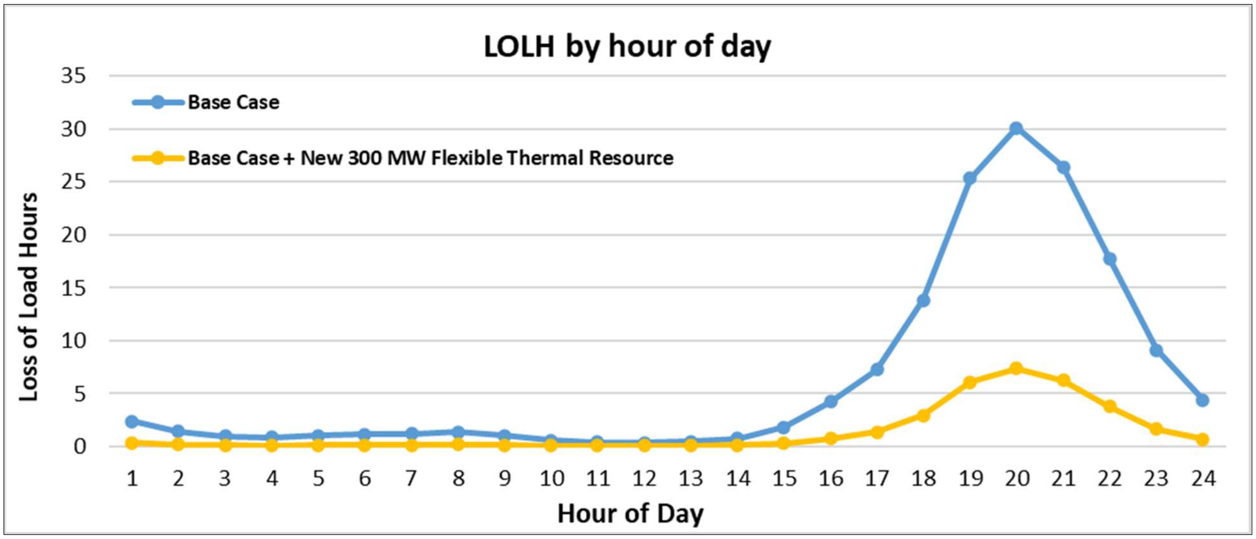
A.5.2. Addition of a New 300 MW Combined Cycle Thermal Resource

This sensitivity analysis investigates the addition of a new thermal resource that is widely available in today's power generation marketplace: a new Combined Cycle (CC) unit with 300 MW of capacity and an assumed forced outage rate of 5%.

Combined cycle power plants offer not only high fuel efficiencies and low outage rates but a high degree of operational flexibility. For Puerto Rico, which is in the process of significantly increasing the amount of variable renewable generation installed on the island, such operational flexibility is very valuable, as it enables the system operator to start and increase/decrease output rapidly to complement and compensate for the intermittency of the growing share of renewable generation. As such, if new thermal resources are to be deployed in Puerto Rico, combined cycle power plants would be a strong candidate for selection.

Comparing to the Base Case, the addition of a 300 MW combined cycle plant is expected to reduce LOLE by 74% (from 36.2 days to 9.4 days) and reduce LOLH by 79% (from 154.2 hours to 33.0 hours). Figure A-15 provides the average annual LOLH for each hour of the day for both the Base Case as well as the sensitivity analysis pertaining to the addition of the new 300 MW combined cycle. Note that the addition of a flexible thermal resource helps to improve system resource adequacy across all hours, including the evening hours when the improvements are needed most.

Figure A-15: Loss of Load Hours by Hour of Day Associated With Addition of 300 MW Combined Cycle



A.5.3. Addition of 25 MW Demand Response (DR) Resources

Demand response (DR) programs involve a region's electric utility being able to call upon retail electricity customers to reduce demand during specified windows of time. The effect of DR appears to the system operator as “negative demand”, which in turn appears equivalent to the addition of supply.

In this sensitivity analysis, a total of 25 MW of new DR resources are modeled, representing slightly less than 1% of Puerto Rico system peak load of approximately 3,000 MW. This is well within the range of reasonableness of the magnitude of resources that can be achieved by DR from retail customers in a regional electricity system. However, it must be emphasized that DR resources are not continuously available, but rather only for brief periods when retail customers are asked to help the system operator by reducing electricity demands from levels that customers would otherwise prefer to consume.

Given that a DR resource would not be continuously available for every hour of the year, DR is assumed for this analysis as being available for up to a maximum of 8 hours in any rolling 24-hour period. Note that this assumption is considered as an approximation of DR availability. Actual operation of DR resources in Puerto Rico might occur differently than assumed in the model, depending upon the capabilities of the DR resource to reduce electrical consumption, the cost of the DR resource, and the specifics of the agreement with the customer, among other items.

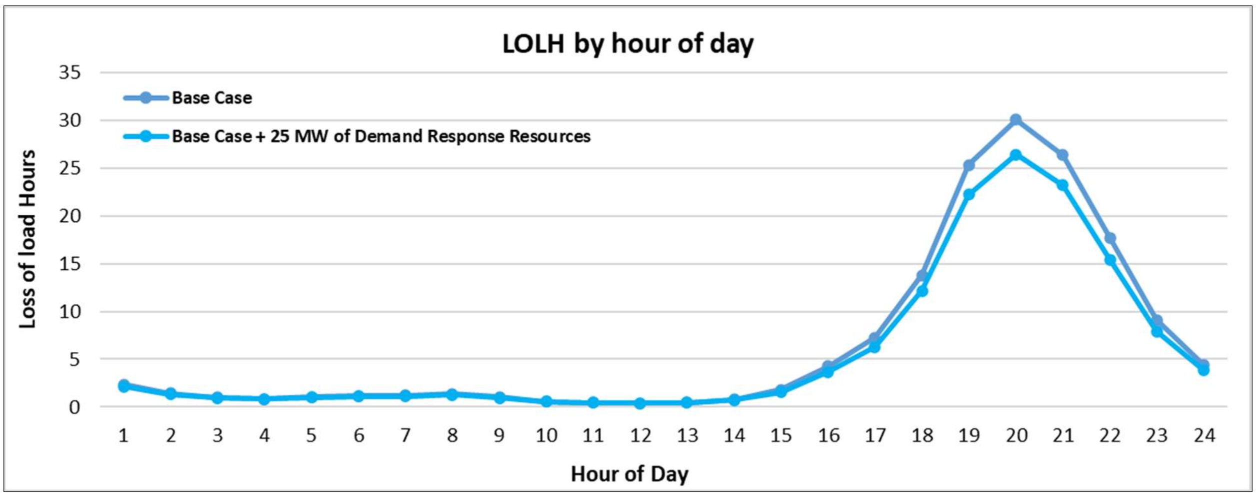
DR resources are only considered as being available after first considering the available capacity of all other generators in the system. In other words, the model considers DR as the last resort option in circumstances where there would otherwise be a generation capacity shortfall. Modeling DR in this manner allows the model to calculate how frequently DR is utilized so that DR is not used more than allowed (i.e., more than 8 hours in any rolling 24-hour time period).

While there is not enough DR available on the island to achieve the 0.1 days per year industry benchmark LOLE target with DR alone – recall that the addition of 850 MW of “perfect capacity” was found to be necessary to achieve the industry LOLE standard – the LOLE and LOLH reductions revealed from the 25

MW DR sensitivity analysis are significant. Results from this sensitivity analysis suggest that just 25 MW of DR has the potential to reduce LOLE by 4 days per year (or 11%), while also reducing LOLH by 18.4 hours per year (or 12%). These improvements are noteworthy especially considering the relatively small size (25 MW) of the assumed DR resource. It is likely that considerably more than 25 MW of DR resources are realistically attainable in Puerto Rico, in which case resource adequacy improvements would be even greater than indicated herein. Further analysis of the true potential of DR in Puerto Rico should be conducted in future resource planning efforts.

Figure A-16 provides the average annual loss of load hours for each hour of the day and for the 25 MW DR sensitivity analysis relative to the Base Case. As is evident, most of the DR utilization (and most of the corresponding improvement in LOLH) takes place between 4 p.m. through midnight, with 67% of DR utilization taking place from 6 p.m. to 10 p.m.

Figure A-16: Loss of Load Hours by Hour of Day Associated With Addition of 25 MW Demand Response Resources



A.6 Changes in Electricity Demand

This section presents resource adequacy modeling results from the following sensitivity analyses that involve changing electricity demand assumptions from Base Case levels:

- 10% load increase in each hour
- 10% load decrease in each hour
- Addition of Electric Vehicles (EVs)
    - 1,500 EVs
    - 3,000 EVs
    - 6,000 EVs

Table A-8 summarizes the LOLE and LOLH results from the sensitivities involving changes in electricity demand assumptions.

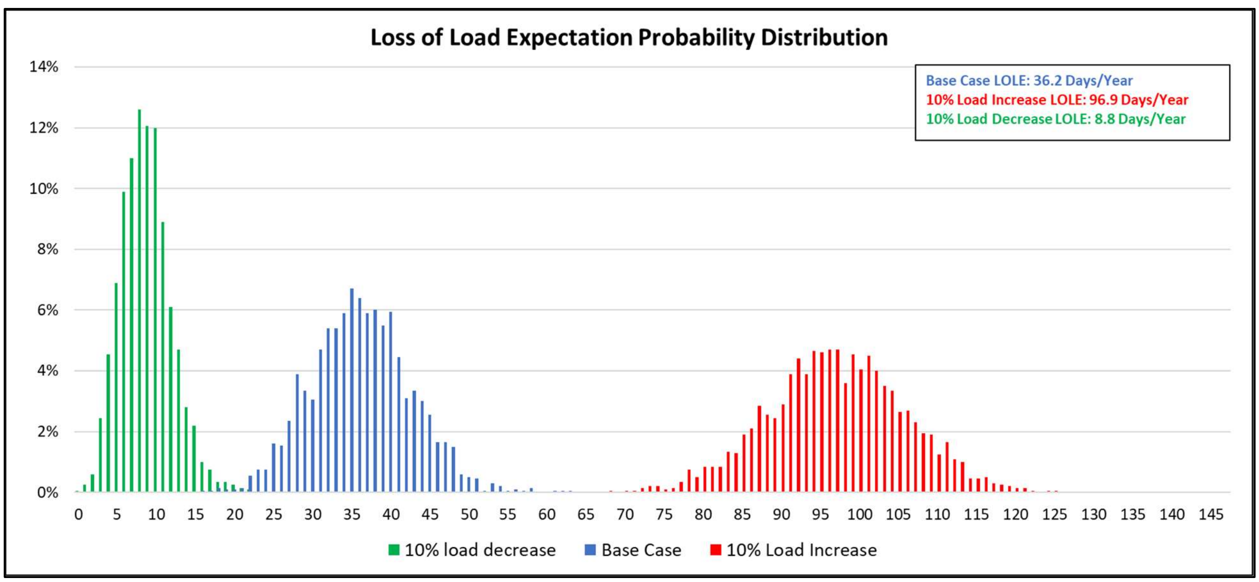
Table A-8: Calculated Resource Adequacy Risk Measures Associated with Load Affected Sensitivities

	Sensitivity Analysis	Loss of Load Expectation (LOLE)	Loss of Load Hours (LOLH)
	Base Case	36.2 Days / Year	154.2 Hours / Year
Base Case +	10% load increase	96.9 Days / Year	501.3 Hours / Year
	10% load decrease	8.8 Days / Year	32.0 Hours / Year
	1,500 Additional EV's	36.0 Days / Year	153.7 Hours / Year
	3,000 Additional EV's	36.2 Days / Year	154.3 Hours / Year
	6,000 Additional EV's	36.5 Days / Year	155.9 Hours / Year
	Industry Benchmark Target	0.1 Days / Year	—

A.6.1 10% Load Increase and 10% Load Decrease Sensitivities

Figure A-17 shows how the probability distribution for LOLE shifts as electricity demand increases by 10% from Base Case levels and decreases by 10% from Base Case levels. On average, a 10% increase in hour-by-hour load increases LOLE by 168% (from 36.2 days/year to 96.9 days/year), whereas a 10% decrease in hour-by-hour load reduces LOLE by 76% (from 36.2 days/year to 8.8 days/year).

Figure A-17: Loss of Load Expectation by Probability Distribution 10% Load Increase & 10% Load Decrease Sensitivities



A 10% change either way in hourly electricity demand is a very large change, especially in Puerto Rico where historical electricity demand has not varied much in the past two decades, as shown in Table A-9 from PREPA's 2019 IRP. To illustrate, before Hurricane Maria in 2017, it took over a decade of general economic decline (from 2005 to 2016) for Puerto Rico electricity demand to fall by 17%.

Table A-9: PREPA Annual Electricity Sales (GWh) by Customer Class 2000-2018

Calendar Year	Residential	Commercial	Industrial	Public Lighting	Agriculture	Others	Total
2000	6,482	7,498	4,101	281	41	165	18,569
2001	6,742	7,632	3,934	253	42	163	18,766
2002	7,120	8,017	3,931	265	43	189	19,565
2003	7,359	8,343	4,005	259	40	159	20,163
2004	7,298	8,371	4,104	256	33	115	20,177
2005	7,460	8,693	4,258	263	34	99	20,806
2006	7,215	8,808	4,213	266	33	85	20,618
2007	7,058	8,866	3,938	270	32	66	20,230
2008	6,473	8,660	3,544	273	30	60	19,040
2009	6,673	8,568	3,094	281	31	57	18,704
2010	6,975	8,677	2,968	280	29	55	18,984
2011	6,587	8,473	2,832	282	28	50	18,251
2012	6,771	8,390	2,683	387	28	61	18,319
2013	6,320	8,621	2,504	285	27	35	17,793
2014	6,218	8,395	2,376	298	26	35	17,348
2015	6,306	8,199	2,355	312	26	37	17,235
2016	6,504	8,176	2,250	319	26	35	17,311
2017	5,012	6,505	1,741	247	20	33	13,558
2018	6,051	7,758	2,128	378	21	38	16,375

While a 10% change in electricity demand is far larger than could reasonably be expected in any one year (or even over the space of a few years), these sensitivity analyses provide directional indication of the relative impacts of increases vs. decreases of electricity demand on resource adequacy in Puerto Rico. In other words, given current resources on the Puerto Rico electricity system, an across-the-board increase in load of whatever magnitude should have a bigger negative impact on resource adequacy than a comparable decrease of load will have in improving resource adequacy.

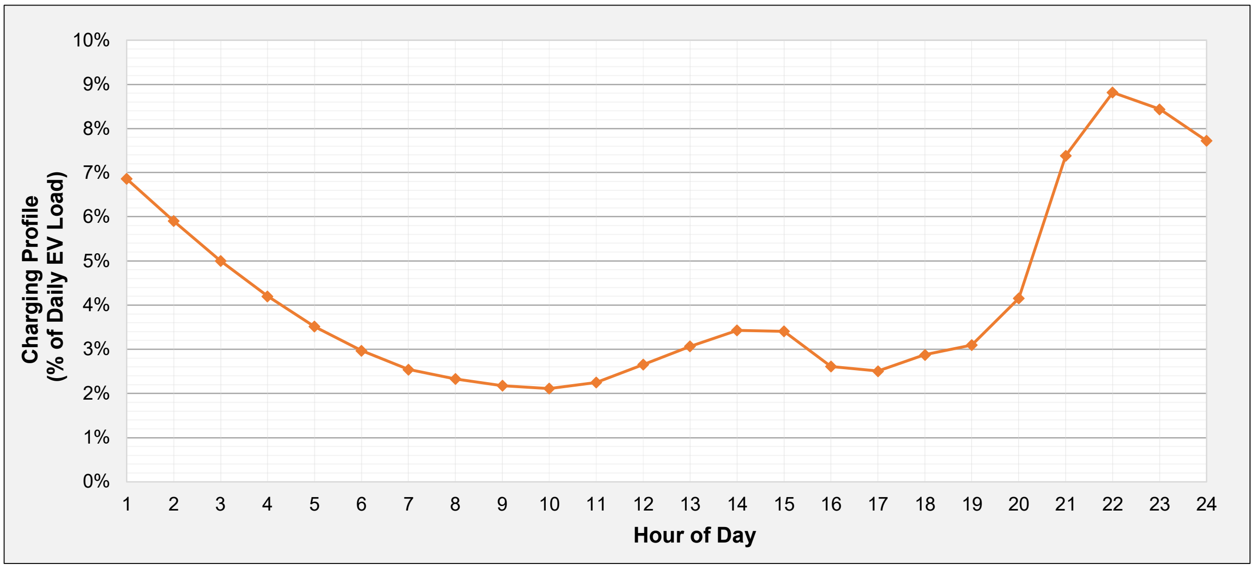
A.6.2 Addition of Electric Vehicles (EVs)

One of the most important phenomena facing regional electricity grids worldwide is the growing adoption of electric vehicles (EVs) and the corresponding implications of EV charging requirements on electricity demand growth, resource adequacy and grid infrastructure expansion needs. To assess this issue for Puerto Rico, resource adequacy sensitivity analysis was undertaken by increasing assumed electricity demands by amounts corresponding to estimated electricity consumption needs to support the addition of electric vehicles to the Puerto Rico automotive fleet. Three variations were considered: the addition of 1,500 EVs, the addition of 3,000 EVs and the addition of 6,000 EVs.

For these sensitivity analyses, each individual EV was assumed to be driven 10,000 miles per year, have an average efficiency of 0.33 kWh per mile[6], and have an average charging efficiency of 90%. The daily charging profile assumed for this analysis is shown in Figure A-17 below, which was developed based on information in the *Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite* tool by the U.S. Department of Energy[7].

Given the above assumptions, the integration of 1,500 EVs to the Puerto Rico electricity grid would add 5,555 MWh annually to system load (+0.03%). Increasing the number of EVs to 3,000 would double the annual load increase to 11,111 MWh per year (+0.06%). With a total of 6,000 EVs, the increase in annual load would double again, to 22,222 MWh (+0.12%).

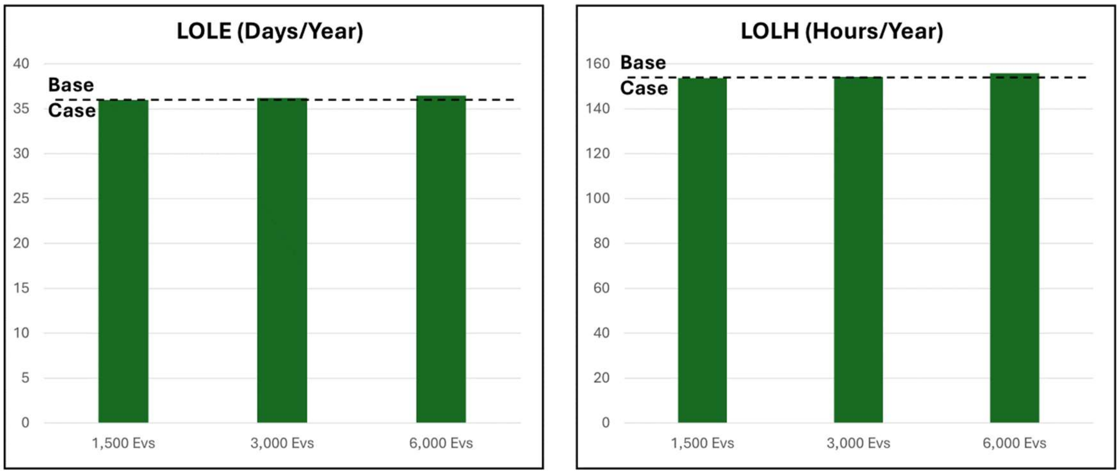
Figure A-18: Assumed Electric Vehicle Charging Daily Load Profile



Thus, even the integration of up to 6,000 EVs in Puerto Rico will have negligible impact on the total system load. Consequently, as shown in Figure A-19, the LOLE and LOLH for these EV sensitivity analyses do not deviate much from values obtained in the Base Case.

[6] https://www.forbes.com/wheels/advice/ev-charging-kilowatts/
[7] https://afdc.energy.gov/evi-pro-lite 2018-2030 IEPR Houly EV Shape

Figure A-19: Resource Adequacy Comparison Among Sensitivity Analyses Evaluating Addition of EV's



Appendix B. Supply Resource Modeling Assumptions

In this Appendix, key assumptions used in resource adequacy modeling are documented for thermal power plants, renewable power plants, and battery energy storage systems.

B.1. Thermal Generation Inputs

Given the high degree of reliance on thermal generation in the Puerto Rico electricity system and the low availability of the thermal power plant fleet, assumptions about thermal generation are vital to this resource adequacy analysis. The following sets of assumptions are especially critical.

B.1.1 Available Capacity

The available capacity of a thermal generator (nameplate capacity minus any derates) defines the maximum reliable capacity contribution of the thermal generator when it is available to serve load (i.e., when the generator is not in either a planned or forced outage). To develop assumptions for the available capacity for each power plant unit, LUMA reviewed the last four years of generation data for each unit, and then calculated the 95th percentile of hourly generation production that each unit achieved for each of the past four years. The rationale for this is that the system operator would typically request all baseload units to produce the highest production capacity they can safely and reliably maintain each day – since the baseload units are also the most efficient units. If the units occasionally produced more than that capacity for less than 5% of the hours, that was judged to not be reliably effective capacity for planning purposes. Figures B-1 through B-12 below present, for each thermal power plant unit, hourly historical generation data between 2020 and 2023 as well as the calculation of available capacity subsequently incorporated in the resource adequacy analysis.

Figure B-1: San Juan CC 5, Hourly Generation – 2020–2023

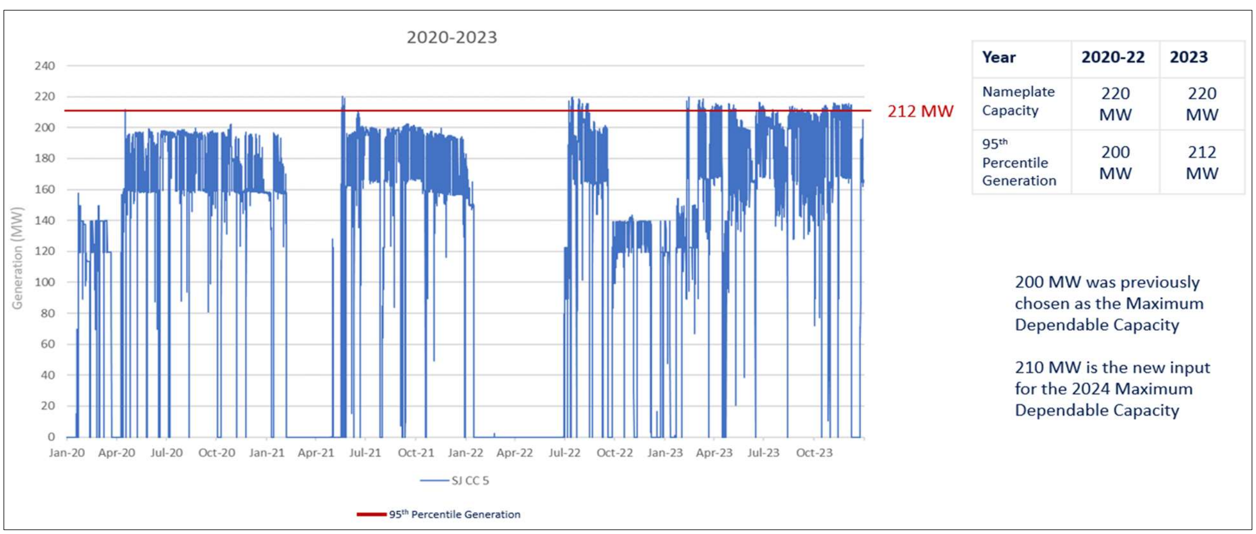
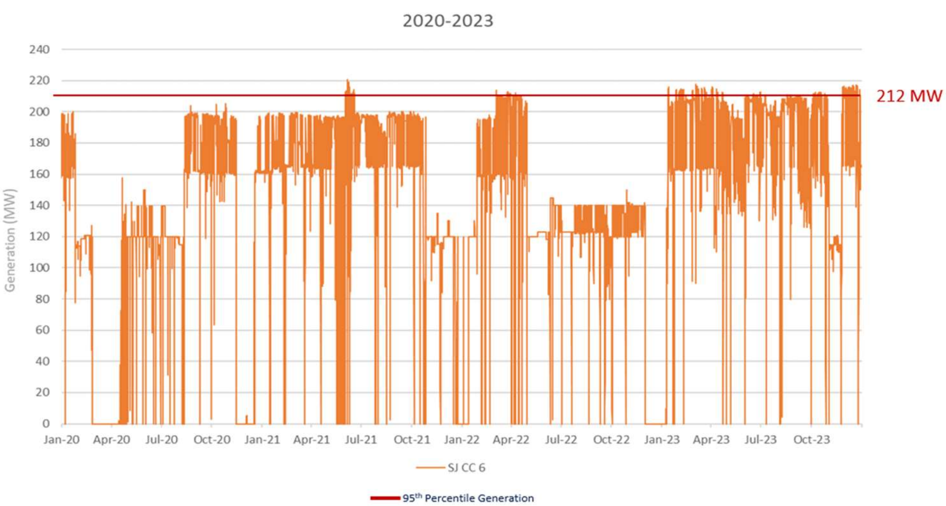


Figure B-2: San Juan CC 6, Hourly Generation – 2020–2023

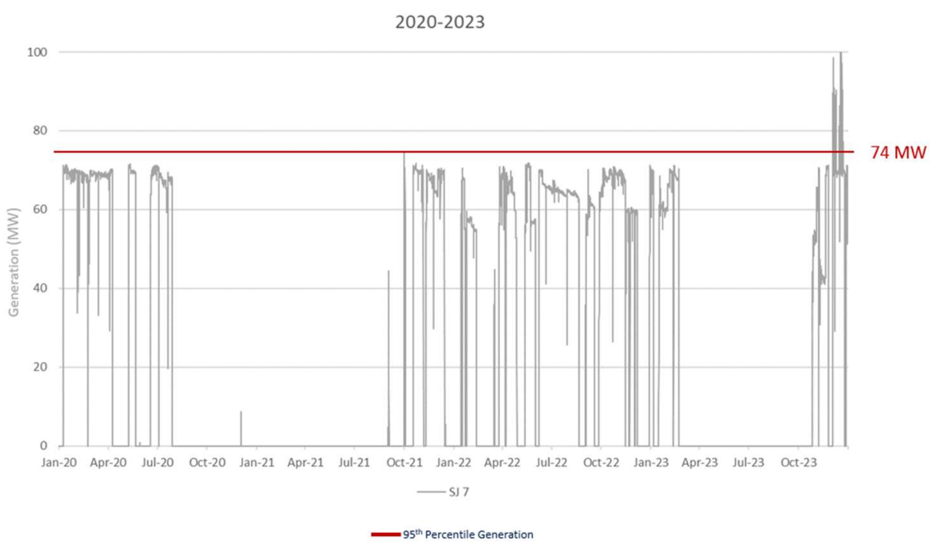


Year	2020-22	2023
Nameplate Capacity	220 MW	220 MW
95th Percentile Generation	199 MW	212 MW

200 MW was previously chosen as the Maximum Dependable Capacity

210 MW is the new input for the 2024 Maximum Dependable Capacity

Figure B-3: San Juan 7, Hourly Generation – 2020–2023

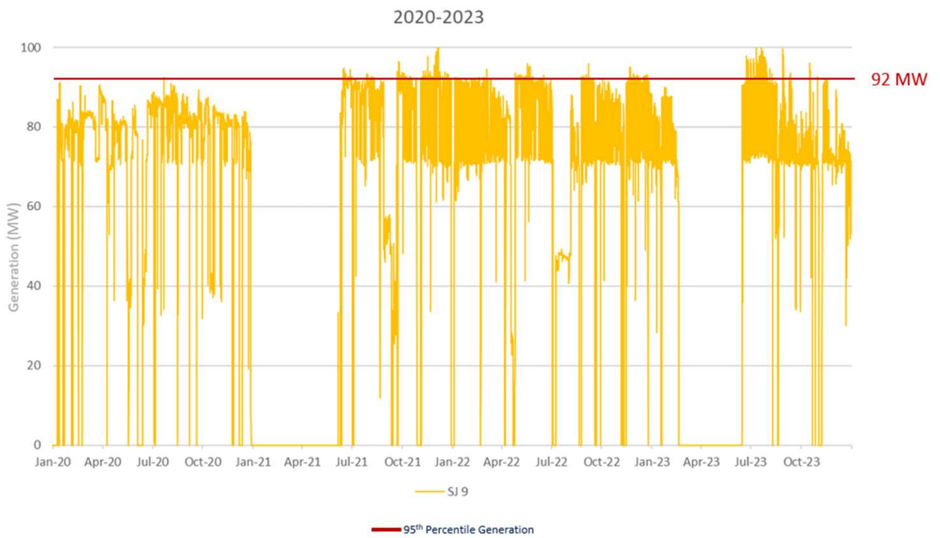


Year	2020-22	2023
Nameplate Capacity	100 MW	100 MW
95th Percentile Generation	71 MW	74 MW

70 MW was previously chosen as the Maximum Dependable Capacity

70 MW is the new input for the 2024 Maximum Dependable Capacity

Figure B-4: San Juan 9, Hourly Generation – 2020–2023

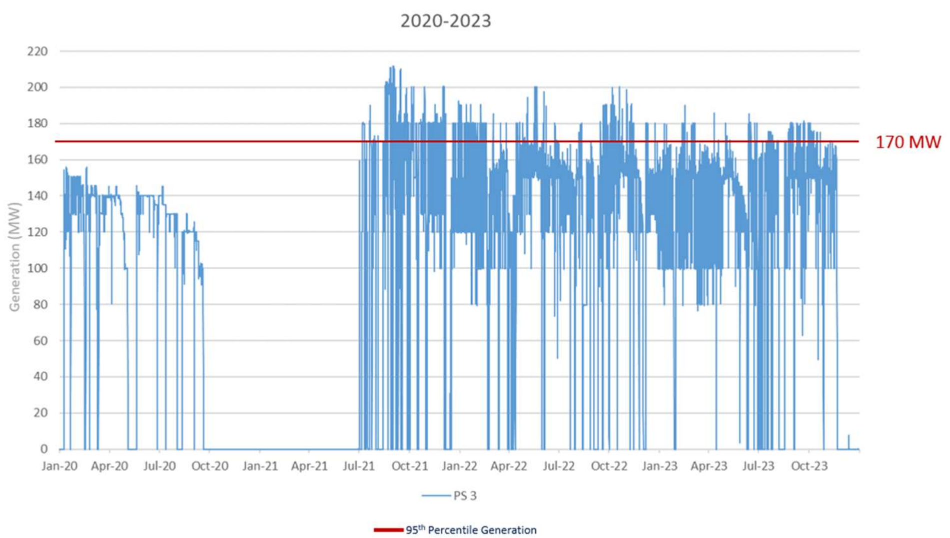


Year	2020-22	2023
Nameplate Capacity	100 MW	100 MW
95th Percentile Generation	92 MW	92 MW

90 MW was previously chosen as the Maximum Dependable Capacity

90 MW is the new input for the 2024 Maximum Dependable Capacity

Figure B-5: Palo Seco 3, Hourly Generation – 2020–2023

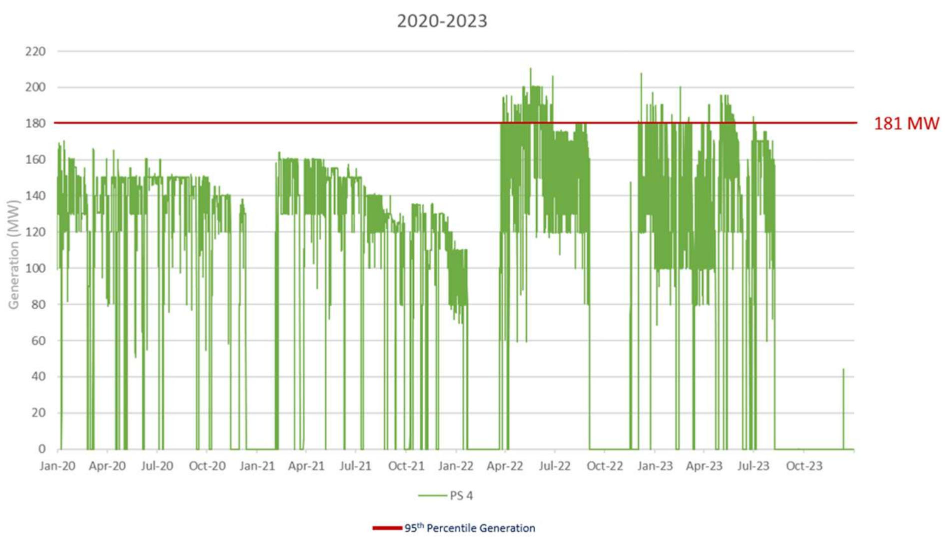


Year	2020-22	2023
Nameplate Capacity	216 MW	216 MW
95th Percentile Generation	181 MW	170 MW

190 MW was previously chosen as the Maximum Dependable Capacity

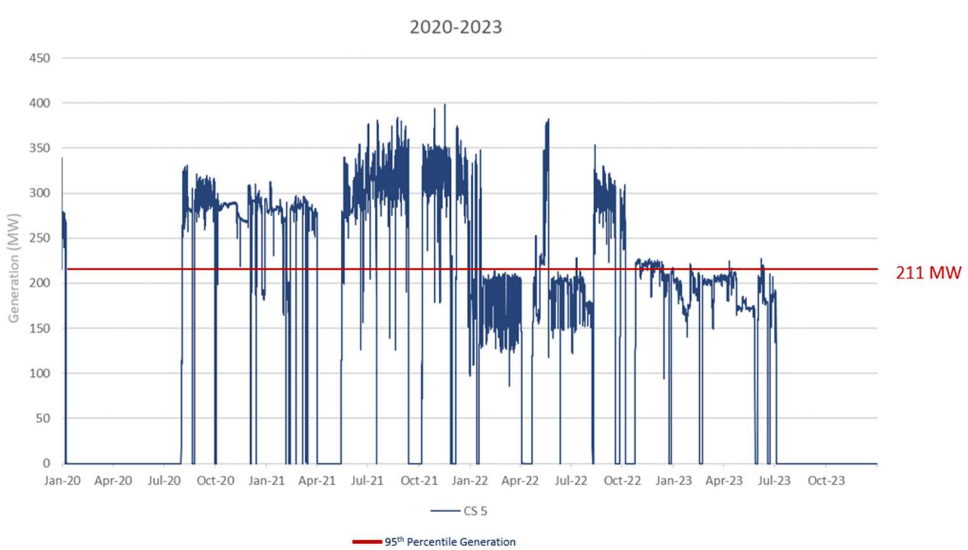
160 MW is the new input for the 2024 Maximum Dependable Capacity

Figure B-6: Palo Seco 4, Hourly Generation – 2020–2023



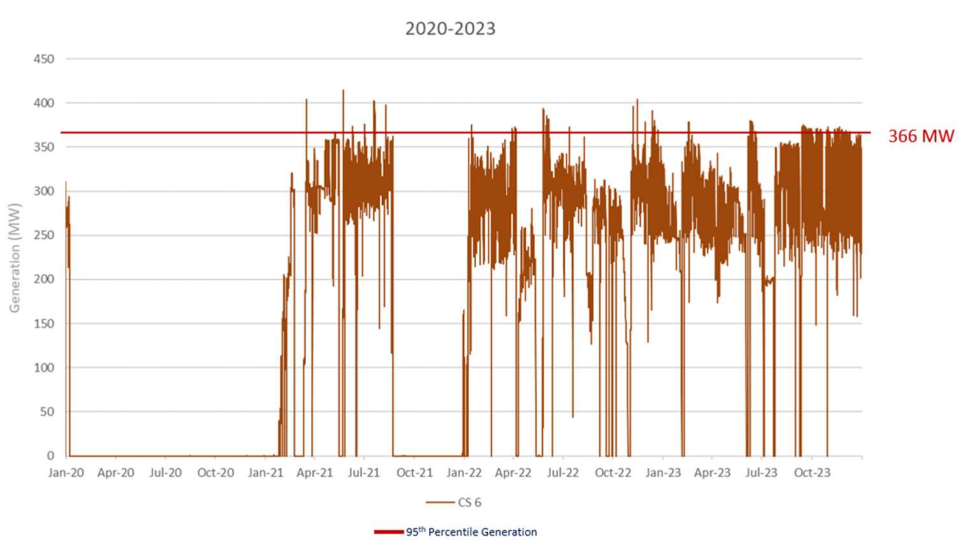
Year	2020-22	2023
Nameplate Capacity	216 MW	216 MW
95th Percentile Generation	180 MW	181 MW

Figure B-7: Costa Sur 5, Hourly Generation – 2020–2023



Year	2020-22	2023
Nameplate Capacity	410 MW	410 MW
95th Percentile Generation	337 MW	211 MW

Figure B-8: Costa Sur 6, Hourly Generation – 2020–2023

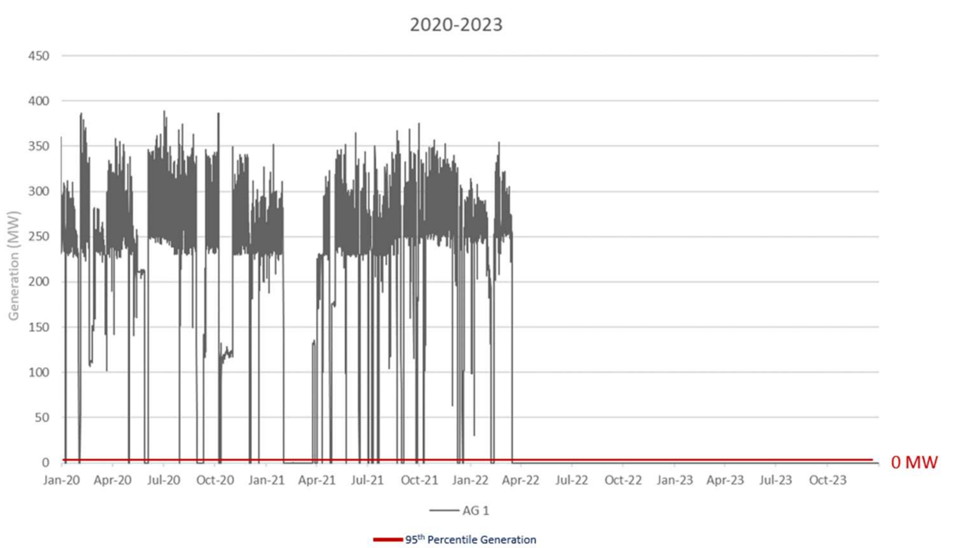


Year	2020-22	2023
Nameplate Capacity	410 MW	410 MW
95th Percentile Generation	351 MW	366 MW

350 MW was previously chosen as the Maximum Dependable Capacity

350 MW is the new input for the 2024 Maximum Dependable Capacity

Figure B-9: Aguirre 1, Hourly Generation – 2020–2023

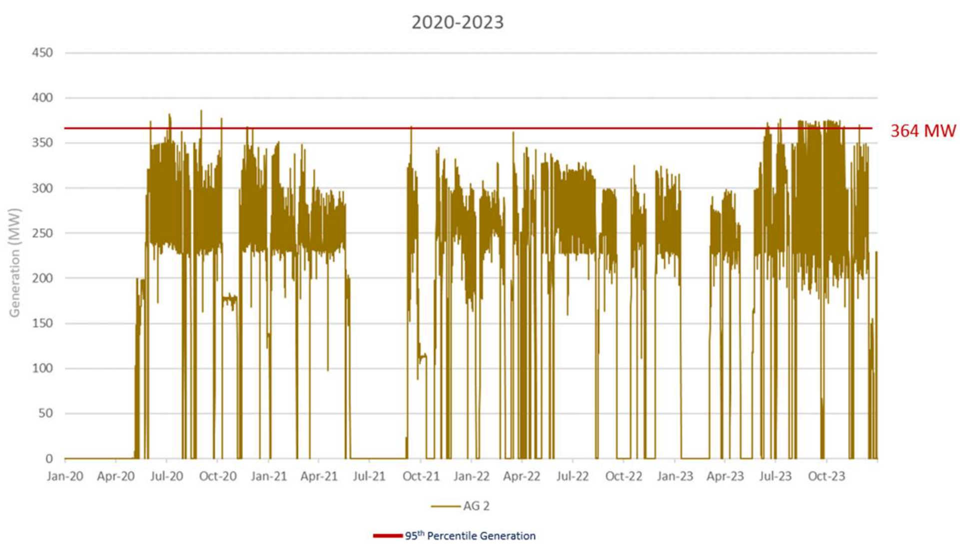


Year	2020-22	2023
Nameplate Capacity	450 MW	450 MW
95th Percentile Generation	328 MW	0 MW

350 MW was previously chosen as the Maximum Dependable Capacity

300 MW is the new input for the 2024 Maximum Dependable Capacity

Figure B-10: Aguirre 2, Hourly Generation – 2020–2023

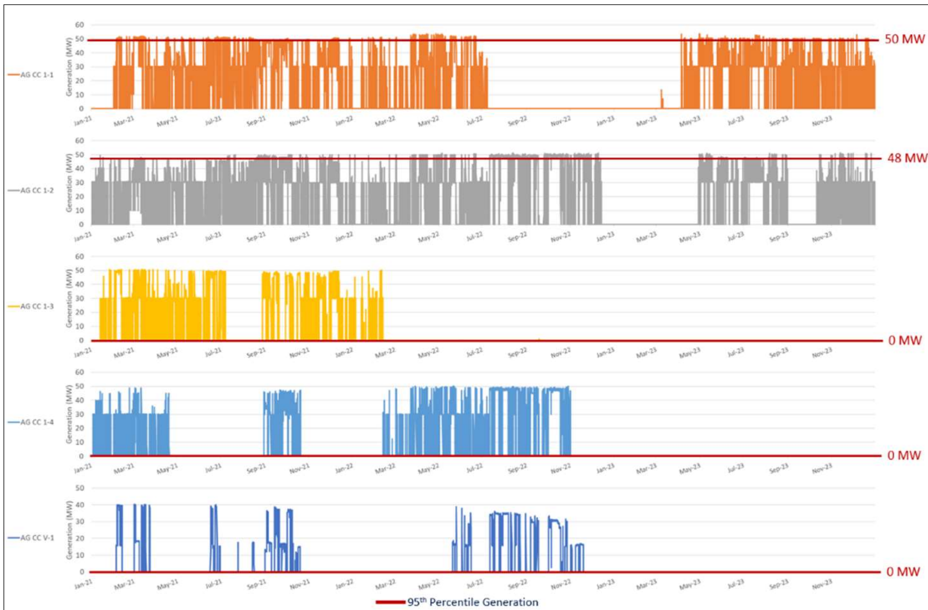


Year	2020-22	2023
Nameplate Capacity	450 MW	450 MW
95th Percentile Generation	328 MW	364 MW

350 MW was previously chosen as the Maximum Dependable Capacity

350 MW is the new input for the 2024 Maximum Dependable Capacity

Figure B-11: Aguirre 1 CC, Hourly Generation –2020–2023

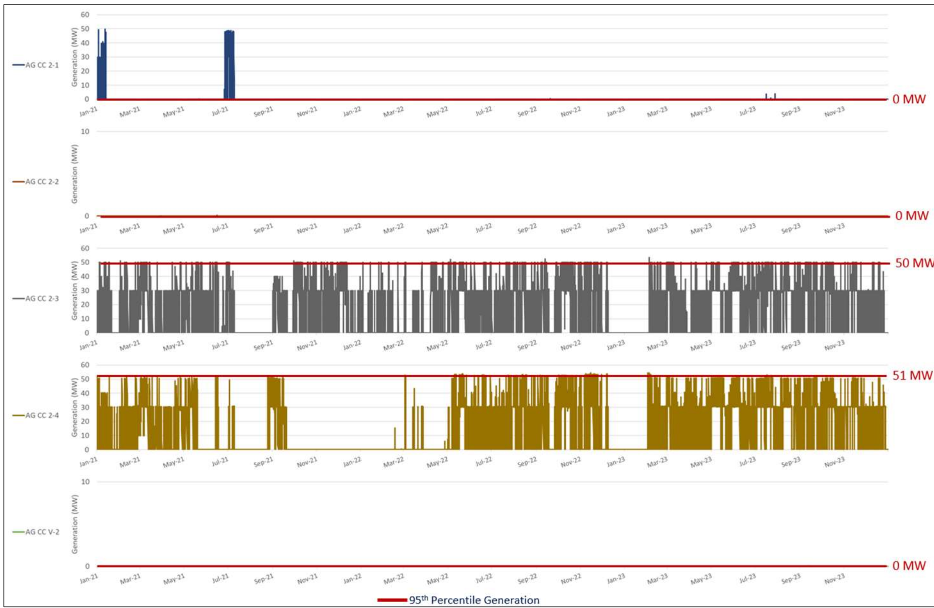


	2021-22 95th Percentile Generation	2023 95th Percentile Generation
AGCC 1-1	51 MW	50 MW
AG CC 1-2	50 MW	48 MW
AG CC 1-3	50 MW	0 MW
AG CC 1-4	49 MW	0 MW
AG CC V-1	39 MW	0 MW

Aguirre CC 1 was previously modeled as 2 units, each with 110 MW Maximum Dependable Capacity

Aguirre CC 1 will now be modeled as 2 units, each with 50 MW Maximum Dependable Capacity

Figure B-12: Aguirre 2 CC, Hourly Generation – 2020–2023



	2021-22 95th Percentile Generation	2023 95th Percentile Generation
AGCC 2-1	49 MW	0 MW
AG CC 2-2	0 MW	0 MW
AG CC 2-3	50 MW	50 MW
AG CC 2-4	52 MW	51 MW
AG CC V-2	0 MW	0 MW

Aguirre CC 2 was previously modeled as 2 units, each with 50 MW Maximum Dependable Capacity

Aguirre CC 1 will still be modeled as 2 units, each with 50 MW Maximum Dependable Capacity

B.1.2. Outage Schedule

This input defines when thermal generators are expected to be out on a planned maintenance outage. Figure B-13 below shows when the thermal units are assumed to be out of operation during FY 2025, either due to planned regular maintenance or because of extended repairs. Any other capacity limitations due to forced outages would be in addition to these planned outages.

Figure B-13: Outage Schedule for Thermal Units in Base Case

Offline = 1 Online = 0	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25
AES 1	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	1 1 1 1	1 1 1 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0
AES 2	0 0 0 0	0 0 0 0	0 0 0 0 0	1 1 1 1	1 1 1 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 1
Ag C.CYCLE 1	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0
Ag C.CYCLE 2	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0
AGUIRRE 1	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 1 1	1 1 1 1 1	1 1 1 1
AGUIRRE 2	1 1 1 1	1 1 1 1	1 1 1 1 1	1 1 1 1	1 1 1 1	1 1 1 1 1	1 1 1 1	1 1 1 1	1 1 1 1 1	1 1 1 1	1 1 1 1 1	1 1 1 1
COSTA SUR 5	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	1 1 1 1 1	1 1 1 1	1 0 0 0 0	0 0 0 0
COSTA SUR 6	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0
ECOELECTRICA CT1	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0
ECOELECTRICA CT2	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0
ECOELECTRICA STM	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0
PALO SECO 3	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0
PALO SECO 4	1 1 1 1	1 1 1 1	1 1 1 1 1	1 1 1 1	1 1 1 1	1 1 1 1 1	1 1 1 1	1 1 1 1	1 1 1 1 1	1 1 1 1	1 1 1 1 1	1 1 1 1
SAN JUAN 7	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	1 1 1 1	1 1 1 1 1	1 1 1 1	1 1 1 1	1 1 1 1 1	1 1 1 0	0 0 0 0 0	0 0 0 0
SAN JUAN 9	1 1 1 1	1 1 1 1	1 1 1 1 1	1 1 1 1	1 1 1 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0
SAN JUAN C. Cycle 5	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	1 1 1 1	1 0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0
SAN JUAN C. Cycle 6	1 1 1 1	1 1 1 1	1 1 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0	0 0 0 0 0	0 0 0 0

Note that Palo Seco 4 is in the middle of a prolonged outage that began in 2023 and is expected by Genera to end in February 2025. By extending this outage by 40%, it is therefore assumed that Palo Seco 4 will be offline through all of FY2025.

Note further that Aguirre 2 is assumed to be offline for the duration of FY2025. This assumption was made to capture the generation capacity deficiency that arises from the increase in the number of forced outage events that occur in the entire generation fleet when baseload units like Aguirre 2 are out of service. (For comparative purposes, note that there were periods during 2023 when 3 or more baseload units were offline at the same time.)

LUMA developed the above planned outage schedule based on a maintenance schedule for the fossil generation fleet provided by Genera on February 28, 2024. This maintenance schedule did not account for any planned outages during FY2025 for some of the big baseload units and assumed only short-duration maintenance outages for other units. However, review of historical data shows that the legacy PREPA plants have historically exceeded planned outage durations by a significant amount. As shown below in Table B-1 during the period from January 2021 to December 2023, the duration of maintenance outages exceeded schedule by approximately 42% when averaged across the thermal generation fleet.

Table B-1: Forecasted Versus Actual Planned Outage Durations 2021-2023

Generator Name	Forecasted Planned Outage Hours	Actual Planned Outage Hours	Variance
Aguirre Steam 1	3,840	5,423	41%
Aguirre Steam 2	2,832	4,004	41%
Costa Sur 5	1,680	1,139	-32%
Costa Sur 6	360	12	-97%
Palo Seco 3	2,472	4,472	81%
Palo Seco 4	3,336	2,265	-32%
San Juan 7	1,296	5,853	352%
San Juan 9	2,184	6,119	180%
San Juan Combined Cycle 5	8,232	12,474	52%
San Juan Combined Cycle 6	528	399	-24%
AES 1	2,376	1,500	-37%
AES 2	2,784	2,163	-22%
EcoEléctrica CT 1	144	78	-46%
EcoEléctrica CT 2	744	928	25%
EcoEléctrica Steam	144	93	-35%
Total Units	**32,952**	**46,922**	**42%**

Reflecting this finding, the planned outages in the maintenance schedule originally provided by Genera were extended by 40% to arrive at the assumed outage schedule presented in Figure B-13.

B.1.3 Forced Outage Rates

The forced outage rate defines the fraction of hours during a year in which a power plant is unavailable because it is inoperative. While the AES and EcoEléctrica power plants exhibit low forced outage rates (approximately 9% and 2%, respectively), the legacy PREPA generation plants now operated by Genera have historical forced outage rates that are significantly higher than industry averages: approximately 29% for baseload and 34% for peaker plants.[8] (For reference, the average equivalent forced outage rate for North American power plants over the past five years was 7.25%.) Accordingly, forced outage rate assumptions for the legacy Puerto Rico generation fleet critically affect resource adequacy modeling.

Forced outage rate assumptions for this resource adequacy assessment are based on historical forced outage rates. Table B-2 provides historical annual forced outage rates for the legacy thermal generators in Puerto Rico since 2013. Note that San Juan 8, San Juan 10, Palo Seco 1 and Palo Seco 2 are out of service indefinitely.

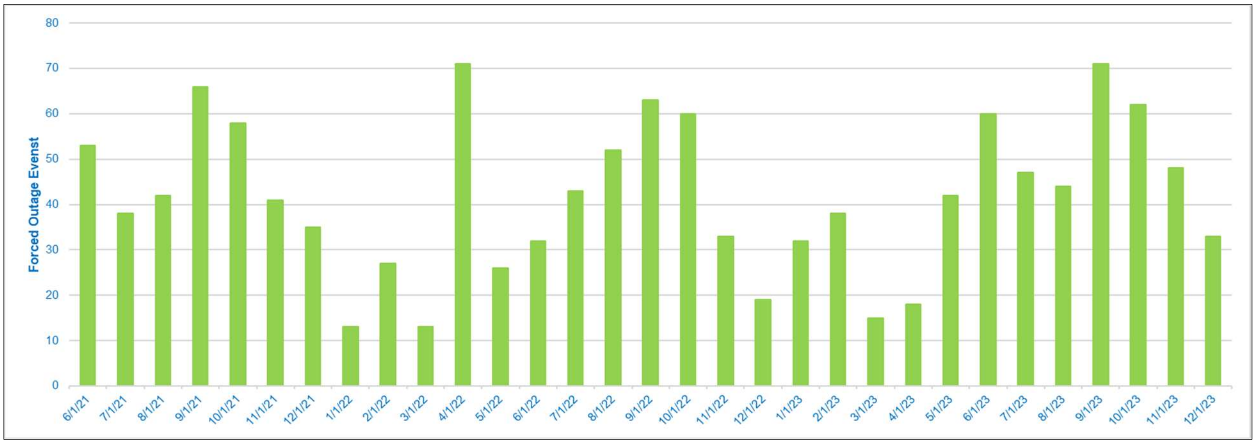
Table B-2: Historic Forced Outage Rates for Thermal Generators

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
SJ CT 5	15%	2%	2%	16%	98%	7%	10%	4%	6%	5%	5%
SJ STG 5	13%	2%	3%	6%	8%	8%	44%	8%	4%	30%	20%
SJ CT 6	1%	51%	30%	5%	5%	2%	7%	6%	2%	2%	3%
SJ STG 6	5%	17%	28%	7%	6%	3%	8%	60%	20%	76%	13%
SJ 7	7%	7%	5%	11%	7%	12%	49%	52%	12%	13%	71%
SJ 8	3%	5%	3%	13%	12%	28%	0%	73%	59%	99%	100%
SJ 9	3%	6%	2%	9%	19%	48%	8%	9%	4%	7%	6%
SJ 10	8%	49%	97%	100%	100%	100%	100%	100%	100%	100%	100%
PS 1	8%	15%	7%	3%	4%	14%	18%	47%	76%	100%	100%
PS 2	2%	1%	6%	13%	100%	100%	100%	100%	100%	100%	100%
PS 3	15%	0%	6%	10%	61%	15%	10%	6%	14%	6%	10%
PS 4	3%	2%	93%	100%	100%	100%	68%	9%	15%	25%	46%
CS 5	0%	2%	1%	0%	0%	5%	10%	59%	7%	13%	54%
CS 6	4%	0%	2%	12%	12%	1%	2%	98%	45%	4%	3%
AG 1	2%	6%	27%	7%	7%	6%	1%	5%	4%	42%	100%
AG 2	3%	2%	11%	100%	15%	3%	77%	27%	17%	20%	16%
AG CC 1	20%	9%	6%	14%	47%	54%	17%	35%	42%	51%	60%
AG CC 2	3%	10%	37%	63%	39%	50%	5%	3%	79%	78%	51%

Notably, as illustrated in Figure B-14, forced outage rates for the legacy thermal power plants are higher during summer months, when reserve capacity is low and available generating units are under duress because they are operating at high levels of utilization.

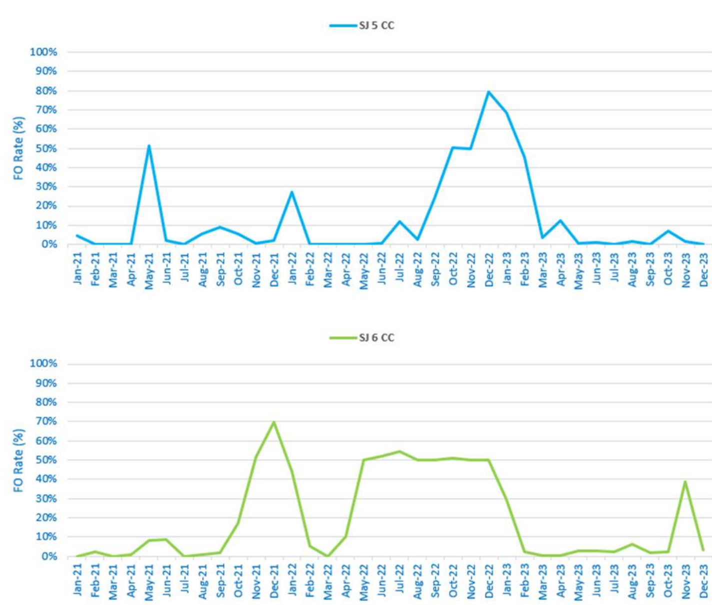
[8] Weighted average by capacity

Figure B-14: Total Forced Outage Events, All Genera Units June 2021 – December 2023



To develop appropriate assumptions about forced outage rates for this resource adequacy analysis, LUMA reviewed forced outage rates for each power plant unit over the most recent six months, year, and past four years. These investigations and the resulting forced outage rate assumptions used for the legacy thermal power plant fleet are presented in Figures B-15 through B-21 below.

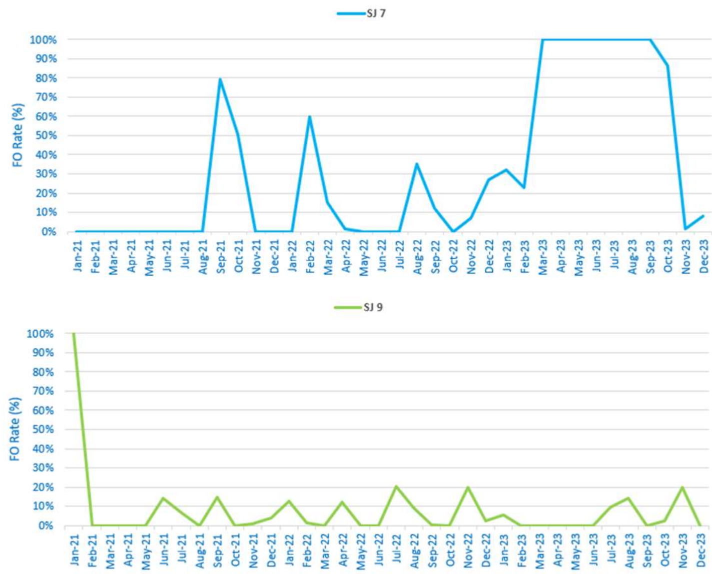
Figure B-15: San Juan CC 5 and 6 Forced Outage Data



- Post Fiona AVG is calculated using data from 10/1/22 - 12/31/23

	36 Month AVG (2021-2023)	Post Fiona AVG	2023 Input	New 2024 input
SJ CC 5	26.02%	35.49%	10%	15%
SJ CC 6	40.15%	27%	10%	15%

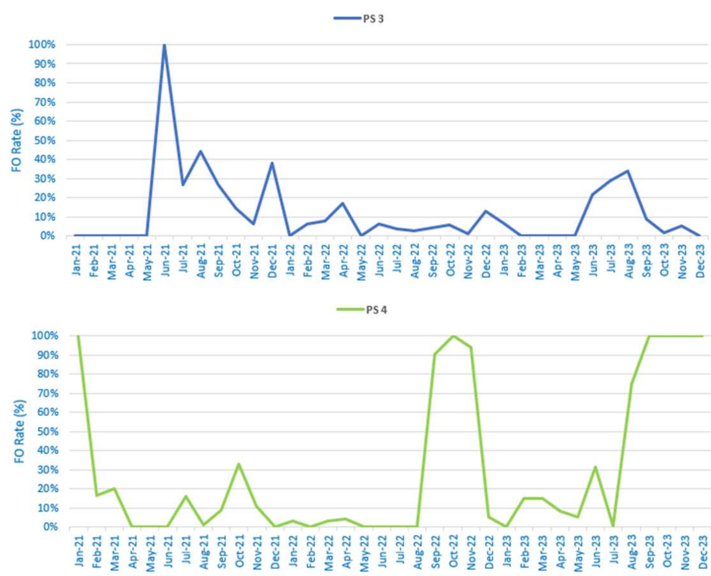
Figure B-16: San Juan 7 & 9 Forced Outage Data



- Post Fiona AVG is calculated using data from 10/1/22 - 12/31/23
- SJ 8 & SJ 10 are out of service without time of return.

	36 Month AVG (2021-2023)	Post Fiona AVG	2023 Input	2024 input
SJ 7	30.44%	57.86%	30%	40%
SJ 9	6.66%	5.10%	8%	8%

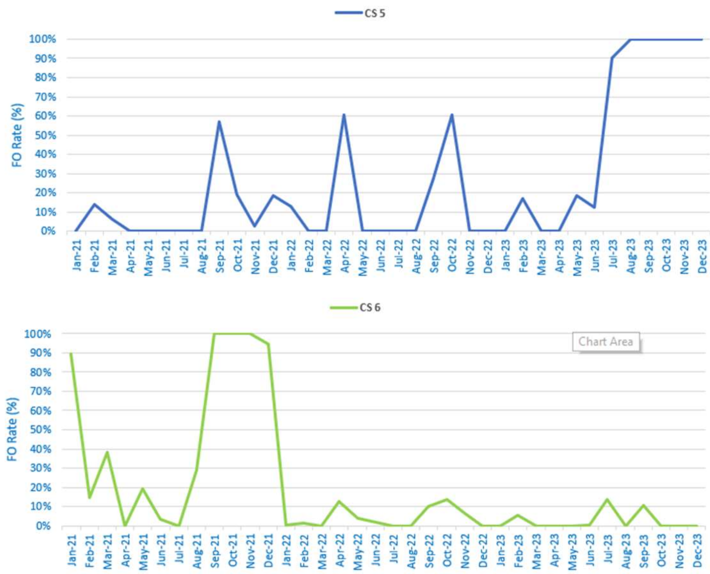
Figure B-17: Palo Seco 3 & 4 Forced Outage Data



- Post Fiona AVG is calculated using data from 10/1/22 - 12/31/23
- PS 1 & PS 2 are out of service without time of return.
- PS 4 estimated time of return is February 28, 2025

	36 Month AVG (2021-2023)	Post Fiona AVG	2023 Input	2024 input
PS 3	9.25%	17.08%	12%	15%
PS 4	26.76%	49.93%	18%	60%

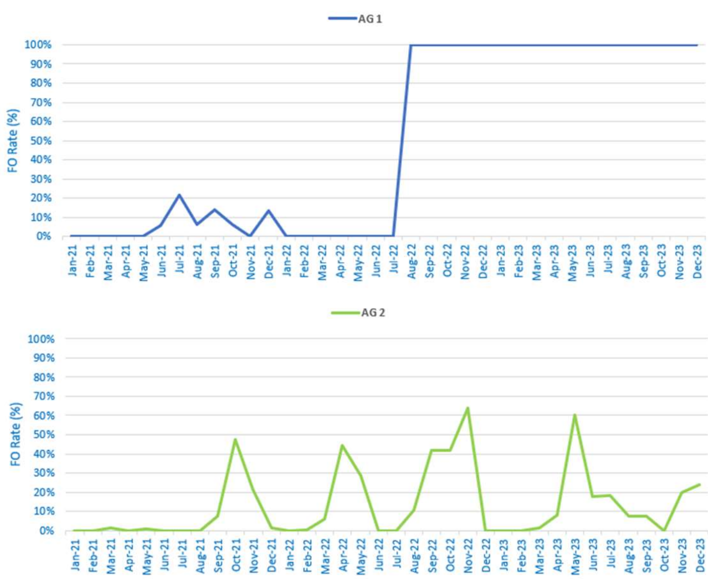
Figure B-18: Costa Sur 5 & 6 Forced Outage Data



- Post Fiona AVG is calculated using data from 10/1/22 - 12/31/23

	36 Month AVG (2021-2023)	Post Fiona AVG	2023 Input	2024 input
CS 5	25.35%	46.84%	10%	20%
CS 6	18.60%	3.33%	15%	15%

Figure B-19: Aguirre 1 and 2 Forced Outage Data



- Post Fiona AVG is calculated using data from 10/1/22 - 12/31/23

	36 Month AVG (2021-2023)	Post Fiona AVG	2023 Input	2024 input
AG 1	46.56%	100%	20%	25%
AG 2	13.32%	18.06%	15%	15%

Figure B-20: Aguirre CC1 Forced Outage Data

- Post Fiona AVG is calculated using data from 10/1/22 - 12/31/23

	36 Month AVG (2021-2023)	Post Fiona AVG	2023 Input	New 2024 Input
AG CC 1-1	58.46%	63.14%	40%	50%
AG CC 1-2	53.06%	62.01%	40%	50%
AG CC 1-3	84.72%	100.00%	-	-
AG CC 1-4	79.47%	94.26%	-	-
AG CC V-1	72.21%	86.17%	-	-

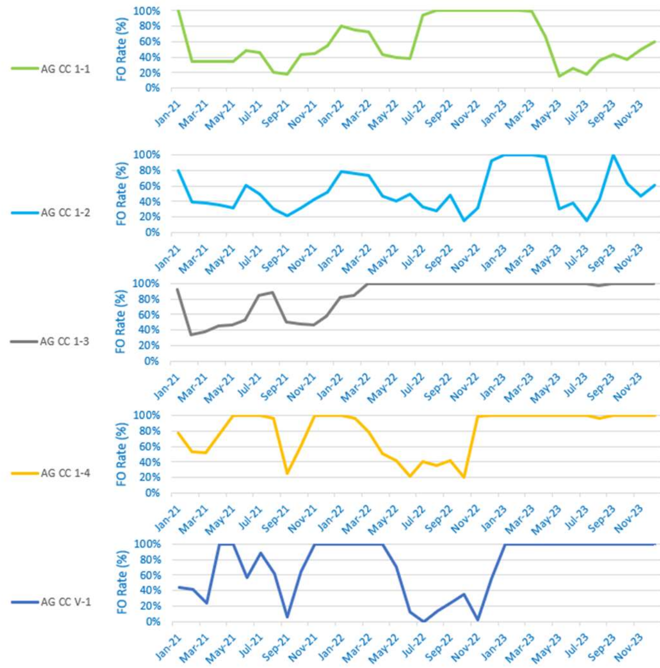
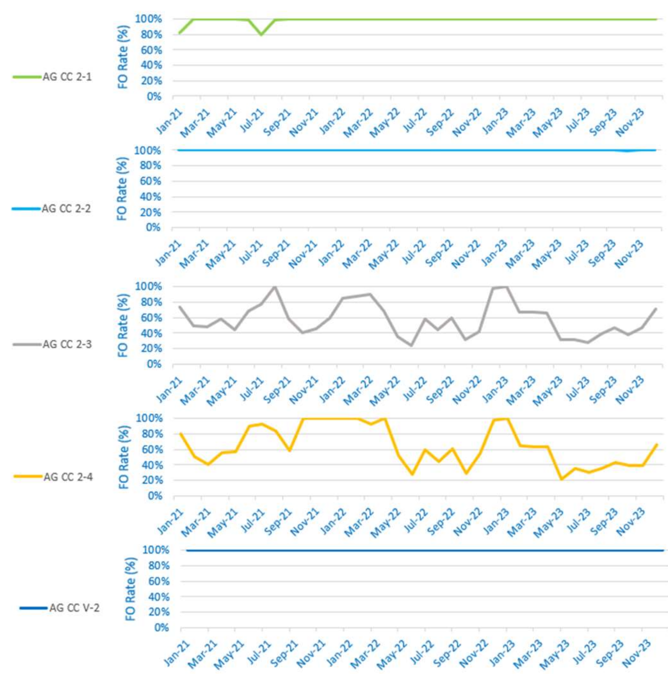


Figure B-21: Aguirre CC2 Forced Outage Data

- Post Fiona AVG is calculated using data from 10/1/22 - 12/31/23

	36 Month AVG (2021-2023)	Post Fiona AVG	2023 Input	New 2024 Input
AG CC 2-1	98.76%	100%	-	-
AG CC 2-2	100%	100%	-	-
AG CC 2-3	57.67%	53.53%	30%	40%
AG CC 2-4	64.72%	52.20%	30%	40%
AG CC V-2	100%	100%	-	-



B.1.4. Forced Outage Duration

This input defines how long it takes a thermal power plant to come back online after a forced outage is simulated to occur. For this analysis, the forced outage duration for all thermal generation is set (by assumption) to 40 hours.

To test this assumption, a sensitivity analysis was performed by LUMA in Appendix 9 of its *FY2023 Puerto Rico Electrical System Resource Adequacy Analysis* report to determine the impact of modeled generator forced outage duration on LOLE and LOLH model output. Five different forced outage durations were considered (keeping individual generator forced outage rates constant across all scenarios): 20 hours, 40 hours, 60 hours, 80 hours, and 100 hours. For each of these five modeling runs, the modeled outage duration was applied for all generators. The results of this sensitivity analysis showed that, as forced outage durations increase, there was a slight decrease in LOLE but no discernable difference in LOLH – illustrating that when modeling forced outages, forced outage rates (which are based on historical generator performance and are a good indication of expected generator availability) are more critical than forced outage durations in resource adequacy evaluations.

B.2 Renewable Generation Inputs and Methodology

It is critical for resource adequacy analysis to properly capture the hourly capacity contributions from renewable power plants based on solar and wind energy, since the hourly contributions of variable generators are, by definition, uncertain. Overestimating the capacity contribution of variable generators will lead to overestimates of resource adequacy, which could cause decision-makers to think the electricity grid has more capability than it really does, thus leaving the system exposed to greater risk of capacity shortfalls in the event the variable generators are unable to generate as expected. Meanwhile, underestimating the capacity contribution of variable generators can make the electrical system appear less reliable than it really is, thus leading to overestimation of (and potentially overinvestment in) new resource requirements.

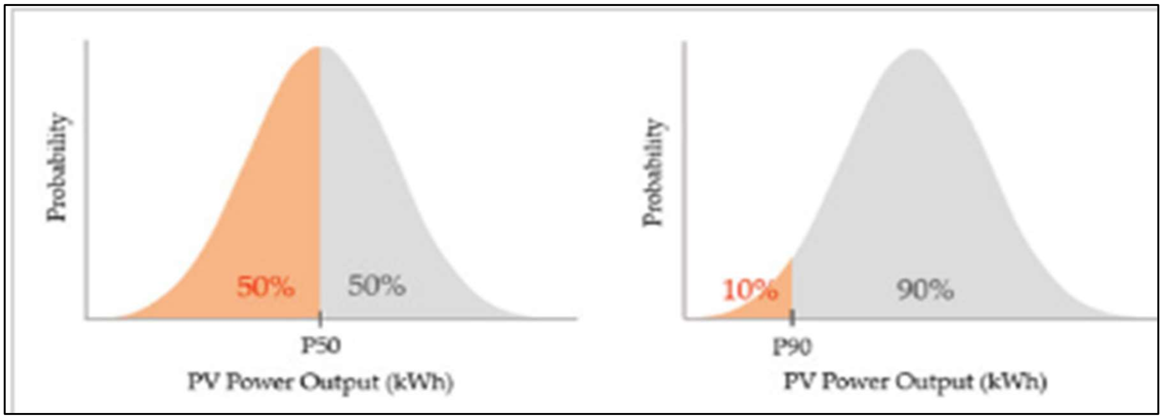
For this resource adequacy assessment, the following assumptions were made regarding electricity generation from wind and solar energy power plants in Puerto Rico.

B.2.1. Existing Renewable Generation

Simulated generation from existing renewable power plants is based on historical operating data from 2019 through 2023 from each power plant. For this resource adequacy analysis, each power plant's historical 50th percentile production level (i.e., P50 production level) for each hour of the day was identified and used.

It is important to note that a P50 generation level is much less conservative than a P90 level, which is the minimum output that can be expected at least 90% of the time during the hour of the day in question. Figure B-22 illustrates how P90 generation levels will always be somewhat lower than P50 generation levels.

Figure B-22: P50 and P90 PV Output Levels by Hour



To gauge the importance of the P50/P90 assumption on resource adequacy results, a sensitivity analysis using the more conservative P90 assumption was compared to the Base Case that incorporates a P50 assumption. As shown in Table B-3, the results illustrate that the use of more conservative P90 hourly capacity contribution from the variable generators only modestly increases system LOLE.

Table B-3: Calculated Base Case LOLE Under P50 vs. P90 Renewable Generation

Scenario	Loss of Load Expectation (LOLE)
Base Case – **P50** Renewable Generation	36.2
Sensitivity Analysis – **P90** Renewable Generation	39.9
Industry Benchmark Target	0.1 Days / Year

B.2.2. Planned Renewable Generation

Several sensitivity analyses presented herein explored the impacts on resource adequacy of adding new renewable energy power projects. For planned renewable energy projects in sensitivity analyses, historical data is not available for developing P50 assumptions on electricity generation that can be anticipated in each hour. Instead, for such future renewable generation sources, forecasted hourly generation is computed based on the historical output of existing renewable resources in Puerto Rico. All forecasted hourly profiles are adjusted to a P50 probabilistic level for each hour of generation prior to performing the simulations. Then, the historical P50 production levels of the combined currently operating renewable generators were used to develop normalized profiles to forecast the expected generation of the planned renewable generators.

B.3 Energy Storage Inputs

Because there is very little energy storage currently installed in Puerto Rico, limited only to a small-amount of behind-the-meter (BTM) customer-sited energy storage, no energy storage resources are assumed in the Base Case resource adequacy assessment. However, since energy storage represents an important opportunity to improve resource adequacy in Puerto Rico, several sensitivity analyses were undertaken that include the assumption of energy storage resources being added, in order to investigate impacts of energy storage on Puerto Rico's resource adequacy.

In sensitivity analyses that include energy storage resources, all energy storage resources are assumed to be based on batteries – hence the term battery energy storage systems (BESS) used throughout this report. All BESS resources are modeled as having an 85% round-trip efficiency (i.e., 15% losses between energy consumed from the grid during charging and energy injected into the grid during discharging), by assumption.

Energy storage resources are modeled such that the normal (non-emergency) discharge time is set to start in the evening, coinciding with peak load. All BESS systems were assumed to be configured with 4-hour duration. The 4 hours of discharge were assumed to occur during peak hours when system load is consistently observed to be highest (between 6 p.m. to 10 p.m.). When discharging begins, energy storage is modeled to inject over the succeeding four hours a total of 60% of the total rated capacity (making the operating range from 20% to 80% of their capacity level). The usage of energy storage is assumed to be limited between 20% and 80% because cycling of BESS resources outside of this range (i.e., discharging all the way to zero, and then charging all the way to 100% capacity) has been found to significantly worsen battery health and shorten lifespan.

If an emergency event occurs (i.e., a time when load exceeds available capacity), energy storage resources are modeled such that they inject stored energy up to the amount needed to meet the system generation shortfall -- or if the generation shortfall is greater that stored energy volumes, to minimize the magnitude of the shortfall. During emergency events, energy storage resources are modeled to inject stored energy as described above, regardless of the time of day or how much energy is stored at that time. Once the amount of stored energy is depleted (i.e., state-of-charge falls to 20% of rated capacity), energy storage resources are unable to inject additional energy, and must wait until non-emergency hours for charging to resume.

Energy storage is modeled in two forms: standalone energy storage and solar-paired energy storage. These two types of storage are modelled differently in the following ways:

- **Standalone Energy Storage.** Standalone energy storage resources are modeled as being able to charge via the grid, with the freedom to charge from any type of available generation resource. These resources are modeled such that charging is allowed to start after midnight, so long as there is excess generation capacity available during that time. The assumed recharge time to replenish the BESS to full capacity is 7 hours. Because of these assumptions, the modeling will generally have standalone energy storage resources reaching sunrise each day fully charged.

- **Solar-Paired Energy Storage.** These storage resources are modeled similarly to standalone energy storage, with the caveat that solar-paired storage can only charge from available solar PV generation. As such, storage paired to solar PV is assumed to begin charging between 8 a.m. - 9 a.m. and then able to continue to charge through the day until sunset. The full expected average hourly solar PV production is assumed to be available to charge the batteries. Because of these assumptions, the modeling will generally have solar-paired energy storage resources reaching sunrise each day at minimum state-of-charge (as noted above, assumed to be 20% of rated capacity).

Appendix C. Resource Adequacy Methodologies

Resource adequacy is the discipline in electric utility planning that assesses the extent to which generation capacity on an electricity system will not be sufficient to serve aggregate electricity demands from all customers on the system under all conceivable conditions over the planning horizon. Resource adequacy informs utility planners and regulators on whether additions to system generating capacity are necessary – and if so, how much new generation should be added.

Historically, this judgment has often been made by considering the region's generation planning reserve margin (PRM). The PRM is defined as the amount (in percent) by which the total system generation capacity exceeds peak electricity demand. A region's PRM thus provides a simple measure of the amount of operational capacity relative to peak demand. However, there is no standard for what an appropriate PRM should be for any given electricity system. While higher PRMs typically equate to a lower risk that load will not be served during a given timeframe, higher PRMs also imply higher costs to society, as it necessarily requires more generation capacity to be in place and operational. In general, PRMs have historically been set by utility planners based on decades of experience in managing a region's electricity system, taking into account the unique characteristics of the system including its fleet of power plants, robustness of transmission network and interconnections to neighboring utilities, electricity demand patterns, and adverse weather conditions the region will face. As a result, PRMs vary from utility to utility, though they have tended to be in the range of 10-25%.

Because the electricity industry worldwide is relying much more heavily on renewable energy sources (solar and wind) that are intermittently available, historical "rules-of-thumb" about resource adequacy based on achieving a fixed level of PRM do not reflect the likelihood that most installed capacity – although operationally functional – will be able to deliver electricity when requested because of lack of sun or wind.

To improve upon resource planning approaches that were based on PRM, modern resource adequacy assessments are rooted in a probabilistic approach to quantify the risk that electricity supply will be unable to fully serve system load every hour of the year. Fundamentally, resource adequacy assessments involve the development of quantitative estimates of the probability that generation supply will be insufficient to serve system load. Note that an indicated resource deficiency does not mean the entire electricity system will go down, blacking out service to all customers. Instead, it signifies that there is not enough generation to serve system load, and that some customers will experience electricity outages.

The results of resource adequacy analyses are typically described by using one or more metrics that aim to capture key concepts associated with the possible loss of electricity service. Three resource adequacy metrics are commonly used, each of which captures different aspects of an electricity system's resource adequacy.

- **Loss of load probability (LOLP):** the estimated probability (between 0 and 100%) that generation supplies will be inadequate to meet demand at least once over a defined period

- **Loss of load hours (LOLH):** the estimated number of hours over a defined period that generation supplies will be inadequate to meet demand

- **Loss of load expectation (LOLE):** the estimated number of days over a defined period that generation supplies will be inadequate to meet demand at least once during that day

These metrics represent different aspects of a system's reliability, encompassing the frequency, duration, and magnitude of generation shortfalls. A higher value for any of these metrics indicates an electricity system that will experience more instances in which generation supplies are inadequate. Accordingly, "target" levels of resource adequacy for an electric utility are usually defined by a maximum acceptable value for one or more of these metrics, such that the electricity system will be assessed to have resource adequacy only if the metric reported from the analysis is below its target level. To illustrate, common practice in the U.S. electricity industry is for utility resource adequacy to be sufficient such that LOLE is no higher than 1 day per decade or 0.1 days per year.

Support for probability-based resource adequacy assessments has increased due to changing electricity load profiles (e.g., the addition of customer-sited rooftop solar, the adoption of electric vehicles), the growth of intermittent renewable resources (e.g., solar and wind), and other factors that affect resource adequacy. Recent NERC surveys[1] indicate that most regional electricity systems in North America are using probabilistic approaches to examine resource adequacy questions, and if they are not, they are considering incorporating probabilistic approaches.

In today's electricity industry, best-practice resource adequacy assessment often begins by establishing a goal or target level for the maximum acceptable number or duration of instances when supply is insufficient to meet system load. Frequently, target levels for loss of load expectation (LOLE) and loss of load hours (LOLH) are set to establish a goal for the region's resource adequacy. For example, in the U.S. electricity industry, common practice is that expected LOLE should be no higher than 0.1 days per year. Then, a probabilistic approach for modeling supply and demand on the electricity system is undertaken to estimate the expected LOLE or the expected LOLH for the electricity system in its current configuration. This type of resource adequacy assessment better incorporates the greater degree of statistical variance in the performance of an electricity system based on an increasing share of intermittent renewables.

Utilizing the results from a resource adequacy study, it is ultimately the responsibility of the regulator to approve any plan subsequently developed to improve resource adequacy, often through an integrated resource planning (IRP) process.

In addition to supporting the development of plans to add new resources to serve system load, resource adequacy analyses can also help utilities set more appropriate planning or operating criteria, such as a requirement to maintain in operating reserves enough generation to cover the loss of the largest generator in the system or a requirement to schedule power plant maintenance during specific months or seasons.

[1] North American Electric Reliability Corporation, Probabilistic Adequacy and Measures, July 2018.

C.1. Effective Load Carrying Capacity

A relatively new metric in electricity resource planning is called the Effective Load Carrying Capacity (ELCC). In simple terms, the ELCC of a generator measures the fraction of the generator's nameplate capacity that can reliably contribute towards system resource adequacy. The use of ELCC as a measure to quantify a generator's contributions towards resource adequacy has become commonplace in the energy industry with the growth in renewable generation sources such as solar PV, wind, and other similar generation technologies, since the variable generation profiles of these types of resources implies the need to make a statistical quantification of the contributions of these generators towards serving system load.

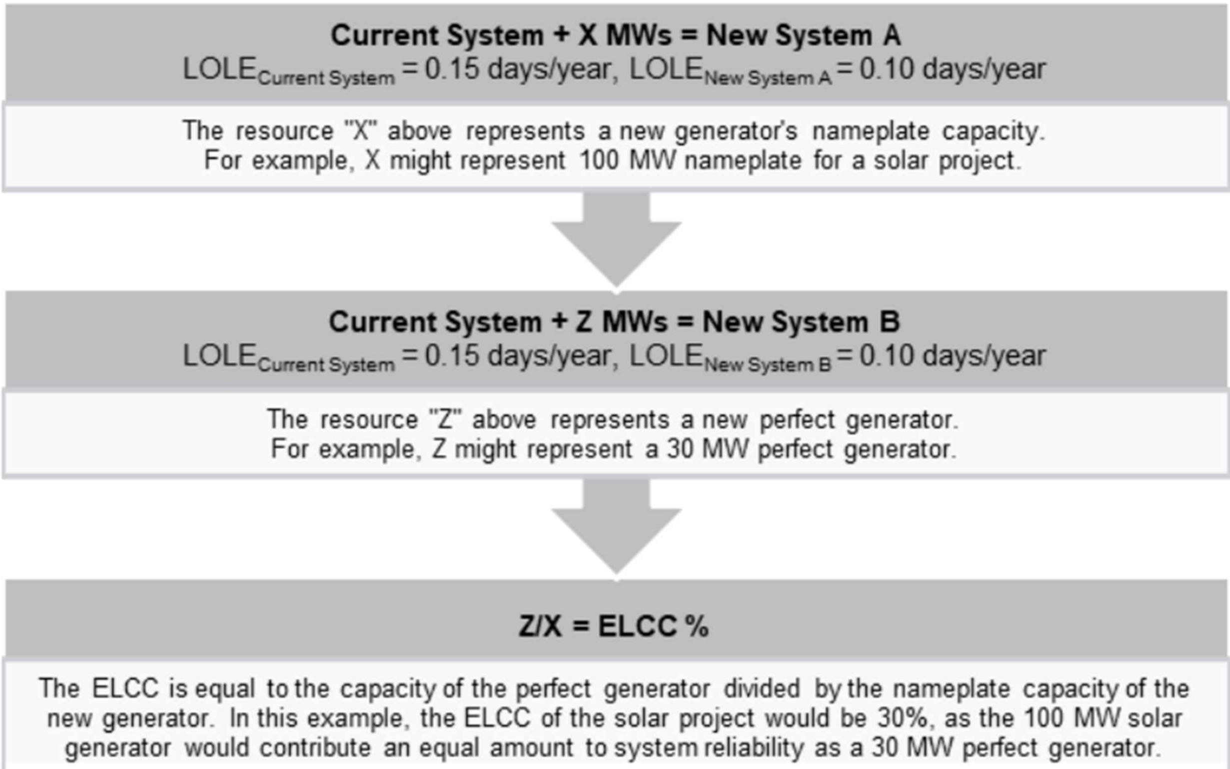
A generator's ELCC depends upon multiple variables relating to its dispatchability characteristics. For example, if generation were needed to meet load in the evening, a standalone solar power plant would have a lower overall ELCC than a solar power plant paired with an energy storage system. This is due simply to the fact that the standalone solar power plant would not be capable of generating much electricity in the evening (since the sun would have nearly set at this time), while the storage system paired to the solar power plant likely could supply electricity to the grid in the evening (provided the storage is sufficiently charged).

ELCC is typically expressed as a percentage of what could be provided by a "perfect generator", or a generator that would be available to dispatch every hour of the day over the course of a year. For example, for resource adequacy purposes a 100 MW solar generator with an ELCC of 25% can equivalently be considered as a 25 MW perfect generator.

It is important to note that the ELCC is a measure of marginal system impact of a new generation addition, or the incremental contribution of a new generator towards resource adequacy. This means that the composition of the existing generation fleet of an electricity system affects the ELCC of a new generator. For example, assume that a 100 MW solar power plant with an ELCC equal to 25% is added to the grid. If a second 100 MW is added to the system, the ELCC of the second 100 MW would be less than 25%, because there are diminishing returns in the cumulative contributions of multiple similar generators towards improving system resource adequacy. Given that there are costs associated with adding new generators, it is important for system planners to assess the appropriate balance between the desired system LOLE target and system cost, especially since the resource adequacy benefits associated with additional generation diminishes with each incremental MW added.

Figure C-1 below describes how ELCC of a generating resource is calculated. First, a new generator is assumed to be added to system, and the improvement to system resource adequacy is noted. Next, a "perfect generator", (i.e., a generator with capacity that is available 100% of the year) is added to the original study system, sized such that the same resource adequacy improvement is achieved. The ELCC is derived by dividing the perfect generator size by the new generator size. The following figure provides a step-by-step example of the calculation.

Figure C-1: ELCC Example Calculation



C.2 Resource Adequacy Practices Elsewhere

A comparison of resource adequacy approaches for selected other utilities and planning entities is provided below. Utilities and planning entities considered in this review were selected based on having similar characteristics to Puerto Rico, including other islands and other parts of the U.S. mainland with similar climate and renewable integration goals.

C.2.1. Resource Adequacy for Other Islands

Maintaining high levels of system resource adequacy is especially challenging for electricity systems that serve islands far removed from a continental landmass. The main reason for this is that islands are not able to import electricity from neighboring utility systems during times of peak demand and/or deficient generation capacity. In contrast, a utility on the U.S. mainland would generally be able to import electricity from neighbors when needed. In addition, many islands, including Puerto Rico, have a relatively small number of total generators available to be dispatched at any point in time. As a result, islands are often at a high risk of not being able to serve load in the event of a loss of a large generator, due to the simple fact that there is a limited number of other generators remaining online that could be dispatched to cover for the large generator's outage. In contrast, planning regions and large utilities in the U.S. mainland can have hundreds, and sometimes thousands, of other generators that could be dispatched to cover for power plant outages.

To compare with Puerto Rico, resource adequacy methodologies were reviewed for three U.S.-based Island electricity systems: the U.S. Virgin Islands, Hawaii and Guam. A summary of the resource adequacy targets used for these three island electricity systems is provided in Table C-1 below.

Table C-1: Resource Adequacy Standards Used in Other Islands Similar to Puerto Rico

Utility / Planning Entity	Target Risk Measure (LOLE, LOLP, LOLH, or Similar Values)
Virgin Islands Water and Power Authority	1 day per year in 2020, reducing 1 day per 10 years in 2044[1]
Hawaiian Electric Company	Energy Reserve Margin, based on 1 day per 4.5 years[2]
Guam Power Authority	1 day per 4.5 years[3]

U.S. Virgin Islands

As one of Puerto Rico's Island neighbors, the U.S. Virgin Islands (USVI) has several similarities to Puerto Rico from a generation resource adequacy perspective. Neither the USVI nor Puerto Rico can import electricity from neighbors (as would be the case on the U.S. mainland), both have similar climates, and both have similar renewable energy goals.

The utility that operates the electrical system for the USVI, the Virgin Islands Water and Power Authority (VIWAPA), released an updated IRP in 2020 where they discussed several items related to resource adequacy considerations.[9] The IRP planning horizon spanned 2020–2044 and notes the requirement that 50 percent of electricity generation in the USVI (as a percentage of peak demand) must come from renewable resources by 2044. VIWAPA's resource adequacy planning criteria sets a loss of load target of 1 day per year in 2024, which gradually reduces to 0.10 days per year by 2044.

In addition, VIWAPA has an "N-1-1" planning criterion, which requires sufficient installed generation capacity to be available during the loss of the two largest generators or two most important transmission lines.

Hawaii

From a resource adequacy perspective, Hawaii also shares several similarities with Puerto Rico. Both Hawaii and Puerto Rico cannot import electricity from neighbors, have similar climates, and both are undergoing the integration of an increasing quantity of renewable resources towards a target of 100% renewables.

The Hawaiian Electric Company (HECO) operates the electrical system in Hawaii. HECO updated its resource adequacy considerations which are summarized in a filing with the state regulatory authority (the Hawaiian Public Utility Commission, or HPUC) titled the 2021 Adequacy of Supply.[10] In its HPUC filing, HECO notes some recent modifications to their resource adequacy planning criteria, namely the implementation of an Energy Reserve Margin (ERM) concept for the purposes of examining resource adequacy in all hours of the year. The ERM is defined as the percentage of excess system capacity over

[9] VIWAPA Final IRP Report, 21 July 2020.
[10] Hawaiian Electric Company Inc., Adequacy of Supply, 29 January 2021.

system load in each hour and accounts for Hawaii's inability to import emergency power from a neighboring utility. The ERM is rooted in HECO's guideline of requiring the system LOLE to be less than one day per 4.5 years.

The ERM concept being used by HECO includes contributions from variable renewable generators, energy storage, demand reduction programs, and other similar resources. HECO defines the dependable contributions from renewable generators to resource adequacy probabilistically, based on the following equation:

$$Dependable\ Capacity_{Hourly} = Average\ Generation_{Hourly} - N \cdot (Standard\ Deviation)$$

In the above equation, the hourly dependable capacity of each renewable generator is equal to that generator's historical production for that hour, reduced by the standard deviation of the historical production. The value of *N* is set by HECO to be 1 for wind generators and 2 for solar generators. For example, if a solar power plant on average generates 100 MW at noon, but with a standard deviation of 20 MW, then only 60 MW would be considered as dependable capacity (100 MW – 2 x 20 MW = 60 MW) at noon.

Guam

Guam's electrical system is operated by the Guam Power Authority (GPA). As an island with a similar climate to Puerto Rico, Guam shares many similar resource adequacy challenges as Puerto Rico. GPA is currently developing an updated IRP; however, previous IRP filings note the island targets a one day per 4.5 years LOLE resource adequacy risk measure [11] GPA indicates that at least a 60% PRM is required to meet this level of resource adequacy. Like VIWAPA in the U.S. Virgin Islands, GPA also utilizes an "N-2" planning criteria, requiring sufficient generation to cover the simultaneous loss of the island's two largest generating sources.

C.3.2. Resource Adequacy for Selected Other U.S. Locations

Across the mainland United States, the critical power system priorities are to achieve and maintain reliable, resilient, and secure capacity and energy that is clean and affordable. Many utilities are subject to Renewable Portfolio Standards (RPS) and carbon emission reduction goals while maintaining Loss of Load Expectations (LOLE) within the industry LOLE standard of 1 day in 10 years.

For instance, in PJM (the grid operator in the vast region from Chicago to Washington DC to Newark NJ, with over 100,000 MW of generating capacity), the recommendation is to maintain an Installed Reserve Margin (IRM) of 17.7% based on the forecast annual peak demand. In an operational assessment, over the most severe months, PJM conducted a Winter Weekly Reserve Target (WWRT) analysis that recommended a reserve target of 28% for December 2023, 30% for January and 25% for February 2024.[12] The WWRT reserve values are substantially higher than the target IRM of 17.7% due to the winter LOLE requirement being set practically to zero (in other words, PJM will not tolerate load-shed events during the winter to prevent households from being without heat).

[11] Guam Power Authority 2022 Integrated Resource Plan.
[12] 2023 PJM Reserve Requirement Study, PJM Resource Adequacy Planning, December 29, 2023

Detailed comparisons of resource adequacy practices on non-island, U.S. utilities and planning regions more closely similar to Puerto Rico are discussed below. [13][14][15][16]

Florida

As the closest state to Puerto Rico, Florida shares similarities to Puerto Rico in terms of climate and solar energy potential and growth. The resource adequacy methodologies used by two utility planning entities within Florida were assessed: the Florida Reliability Coordinating Council and Florida Power & Light.

Florida Reliability Coordinating Council

The Florida Reliability Coordinating Council (FRCC) is a regional entity responsible for assessing and ensuring reliable operation of the bulk power system in Florida, as is required by the state regulatory authority (the Florida Public Services Commission, or FPSC). FRCC is comprised of several different member organizations, including local utilities, electricity cooperatives, and other similar organizations. FRCC receives data annually from its members to develop a regional load and resource plan to produce an electricity reliability assessment report [17] This plan projects electrical system performance for the FRCC region by analyzing reserve margins, LOLP, forced outage rates, and other related items.

Although Florida is not an island, electricity transfer limitations and modeling scenarios assuming the lack of ability to import power are considered within FRCC studies. One item that is directly applicable to Puerto Rico is FRCC's adequacy calculation, which removes the availability of firm electricity imports from Georgia (Florida's main intertie to the rest of the U.S.), so that FRCC treats the region as an island for resource adequacy calculation purposes. The most recent FRCC report notes that the system is able to meet a 0.10 days per year planning criteria even if imports are restricted to zero, with reserve margins meeting or exceeding 20% in each year of the ten-year study. However, the sheer number of generators and size of the electricity system in Florida does inherently reduce resource adequacy vulnerabilities when compared to smaller systems such as Puerto Rico's.

Florida Power & Light

Within the FRCC region, Florida Power & Light (the largest utility in the state) conducts its own jurisdictional resource planning analysis in accordance with state policies [18] While Florida Power & Light also plans for a target LOLE of 0.10 days/year, the utility also enforces two other resource adequacy criteria:

- A 20% total reserve margin should exist for the summer and winter
- At least 10% of the total reserve margin must come from centralized generators

The planning criteria above are unique in that they address the desire for diversification in how resource adequacy needs are met within Florida, showing how utilities can set unique planning criteria based on the characteristics of their specific location.

---

[13] California Independent System Operator, Resource Adequacy Working Group Discussion Paper, September 2023
[14] Florida Power and Light (FPL), Ensuring Reliable Service, https:/www.fpl/reliability.html
[15] California Independent System Operator, Resource Adequacy Working Group Discussion Paper, September 2023
[16] 2023 PJM Reserve Requirement Study, PJM Resource Adequacy Planning, December 29, 2023
[17] FRCC 2021 Load & Resource Reliability Assessment Report V1, 29 July 2021.
[18] Florida Power & Light Company, Ten Year Power Plant Site Plan 2023-2032.

California

Among regional electricity systems around the world, California is a leader in many aspects of transitioning to electricity supply based heavily on distributed renewable energy.

In California, the prevailing renewable portfolio standard requires 60% of the state's electricity come from carbon-free resources by 2030, with the requirement increasing to 100% by 2045. (By comparison, Puerto Rico is also currently pursuing significant growth in solar generation to meet the island's own renewable portfolio standard of 40% by 2025, 60% by 2040, and 100% by 2050.) The state regulatory authority (California Public Utilities Commission, or CPUC) establishes resource adequacy obligations for all load serving entities (LSE) supplying to retail electricity customers, including the three investor-owned utilities (e.g., Southern California Edison, Pacific Gas & Electric, San Diego Gas & Electric), within state jurisdiction.[19] The state resource adequacy program for each LSE contains three distinct requirements:

- Load serving entities are required to meet a 15% PRM on top of their approved load forecast.
- Each local area must have sufficient capacity to meet energy needs for a 1-in-10 worst weather scenario and an N-1-1 contingency event (e.g., the loss of the two largest generators).
- Load serving entities are required to procure "flexible capacity", or capacity that can quickly be dispatched and ramped to full power. Specifically, enough flexible capacity must be procured to meet the largest three-hour ramp in system load (defined on a monthly basis). The reason for this resource adequacy requirement stems from the fact that there is a significant amount of intermittent generation (i.e., solar energy) installed in the California. As a result, the California electrical system can sometimes see sharp swings in supplied generation if clouds quickly appear, during sunsets, etc. Examples of flexible capacity include dispatchable resources such as energy storage, fast ramping thermal units (such as engines, combustion turbines, combined cycles), etc.

At the wholesale level, taking resource adequacy to a higher level and setting goals monthly instead of annually, the California ISO has implemented the "Slice-of-Day" program,[20] which requires each capacity and generation entity to demonstrate enough capacity to satisfy its forecast load in all 24 hours of the "Worst Day" (the day with the highest peak load) of each month.

The CPUC performs detailed analyses to determine the generator's effective load carrying capacity (ELCC), which is the fraction of rated capacity that a generator can contribute toward resource adequacy requirements. The ELCC of a generator is defined by how much system loads can increase when the generator is added into the electrical system, with equivalent performance in terms of system resource adequacy. In California, the ELCC calculation is based on an enforcement of a 0.10 days/year LOLE target[21].

The ELCC of a generator varies by technology type and the capability of the generator to contribute towards serving load when generation is needed most. For example, if generation were needed to meet a load peak occurring in the evening, a stand-alone solar power plant is likely to have a lower ELCC than a solar power plant paired with an energy storage system, due simply to the fact that the stand-alone solar

[19] California Public Utilities Commission, 2021 Resource Adequacy Report.
[20] California Independent System Operator, Resource Adequacy Working Group Discussion Paper, September 2023
[21] Incremental ELCC Study for Mid-Term Reliability Procurement. January 2023 Update.

power plant would not be capable of generating much electricity in the evening (since the sun would have nearly set at this time), while the storage system tied to the other solar power plant likely could generate some electricity in the evening. ELCC will also vary from one planning region to another because the timing and duration of peak demand levels differ from region to region.

In summary, Table C-2 presents the key resource adequacy considerations for the above geographies (along with selected other geographies). The column labelled "Target Adequacy Risk Measures" indicates the target levels of loss of load that each region's planning entity strives to meet. For example, a value of "0.1 days per year" means that the electricity system should assign a 10% probability that, in any given year, there will be an occasion in which load cannot be fully served by available resources.

Table C-2: Comparison of Resource Adequacy Methodologies

Utility / Planning Entity	Target Risk Measure (LOLE, LOLP, LOLH, or other)	Notes
Virgin Islands Water and Power Authority	LOLE 1 day/year in 2020, declining to 0.1 days/year in 2044	U.S. territory islands neighboring Puerto Rico, similar climate and lack of electricity import ability. Additional N-1-1 planning criterion requires sufficient installed capacity to cover loss of two largest resources. Target LOLE for 2044 is a recent goal set forth in the 2019 IRP.[1]
Hawaiian Electric Company	Energy Reserve Margin (ERM), based on LOLE 1 day/4.5 years	U.S island with similar load profile, generation, climate, and inability to import electricity as exists in Puerto Rico. HECO bases their resource adequacy criteria on a one day per 10 years guideline for assessing resource adequacy. This LOLE target helps to inform the ERM planning criteria, which is the percentage by which the system capacity must exceed the system load in each hour, considering all generation and load reduction sources, including renewable and storage resources (Hawaii's previous planning criteria did not account for the contributions made by renewable generators).[2]
Guam Power Authority	LOLE 1 day/4.5 years	U.S. territory island with similarities to Puerto Rico in terms of climate, and lack of electricity import ability. The Guam Power Authority requires a minimum reserve margin of 60%[3].
Florida Reliability Coordinating Council	LOLE 0.1 days/year	Florida has a similar climate to Puerto Rico, and similar probability of hurricane events. Florida's LOLE performance is measured under various system conditions, including zero import availability, and varying solar generation levels. Aggressive solar integration targets 30 million solar panels installed by 2030.[4]
Florida Power & Light	LOLE 0.1 days/year	Florida Power & Light is a vertically integrated utility located in Florida. In addition to the 0.1 day/year LOLE planning criterion, Florida Power & Light maintains 10% generation-only PRM criterion and a 20% total PRM criterion (including other resources, i.e., demand side-reduction, etc.) for summer and winter seasons.[5]
Southern California Edison	LOLE 0.1 days/year 0.02-0.03 days per month	Southern California Edison's Integrated Resource Plan studied a 0.1 days per year LOLE standard and considers the latest renewable and environmental/emissions targets. Results showed a need to increase the PRM to 16% in 2026, 17% in 2030 and 18% in 2035 to maintain the traditional 0.1 days per year LOLE standard.[6]

Arizona Public Service Company	LOLH 24 hours over 10 years	Arizona Public Service Company has a 100% clean energy goal for 2050 that includes carbon-free resources like solar, wind, demand-side management, and nuclear. As part of the 2030 interim clean energy goal, a 45% requirement for renewable generation is required. Results from Arizona Public Services' 2020 IRP Reserve Margin Study indicate a 15% reserve margin is sufficient to meet the company's resource adequacy requirements.[7]
Tucson Electric Power (Arizona)	15% Planning Reserve Margin	Tucson Electric Power is a utility in the desert southwest region of the U.S. with high solar potential. The utility follows a 15% planning reserve margin guideline, supported by various probabilistic analyses. The referenced IRP investigates numerous renewable penetration levels, and the utility has set a carbon reduction target of 80% by 2035 relative to 2005 levels. The IRP investigates the ramping capabilities / needs of generation to support renewable growth in the electrical system.[8]
Public Service Company of New Mexico	LOLE 0.2 days/year	New Mexico has a strong solar potential and a similar load curve to that of Puerto Rico. The Public Service Company of New Mexico IRP is driven by 100% emissions free goal by 2040. It also lists its goal to transition to the industry standard LOLE of 0.1 days per year.[9]
Puget Sound Energy (Washington state)	LOLP of 5% per year	Puget Sound Energy is required by Washington state law to ensure 80 percent of electric sales are met by non-emitting/renewable resources by 2030, and 100 percent by 2045. Puget Sound Energy uses a resource adequacy model to calculate various resource adequacy risk measures that quantify the risk of not serving load, establish peak load planning standards, and quantify the peak capacity contribution of renewable resources.[10]

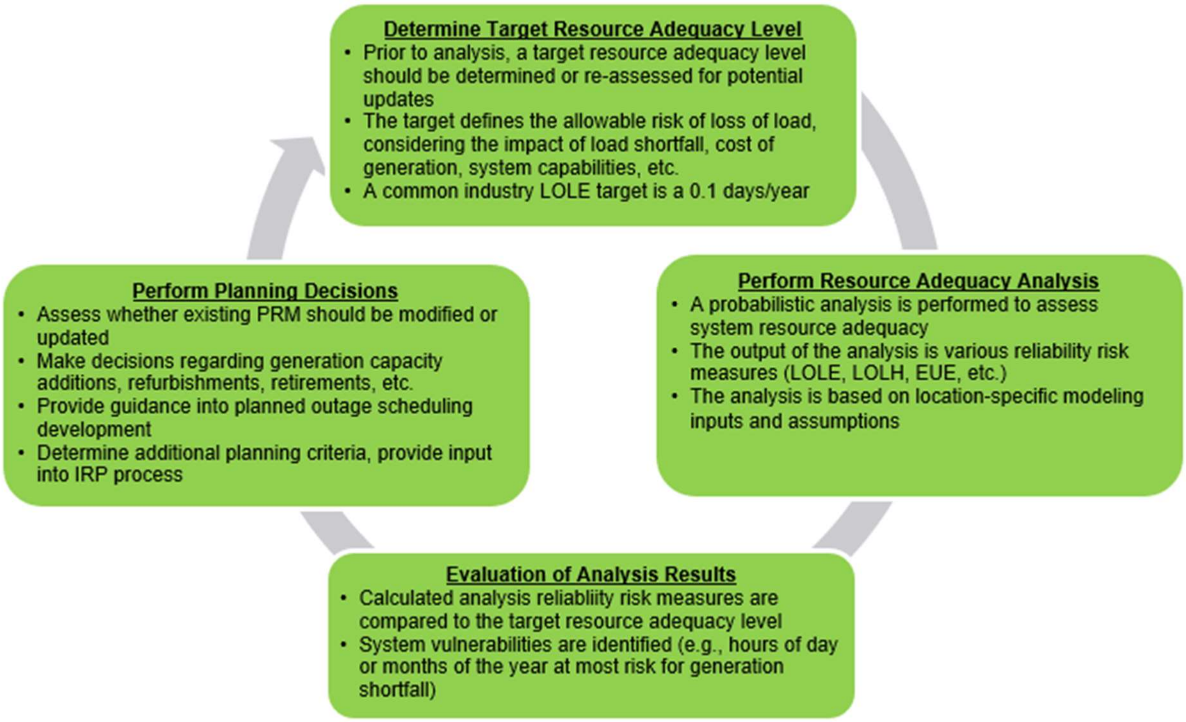
Sources

1. VIWAPA Final IRP Report, 21 July 2020.
2. Resource Adequacy Supply Report 2021.
3. Guam Power Authority 2022 Integrated Resource Plan.
4. FRCC 2022 Summer Load & Resource Reliability Assessment Report, May 2022.
5. Florida Power & Light Company, Ten Year Power Plant Site Plan 2023-2032.
6. Southern California Edison Integrated Resource Plan, November 2022.
7. Arizona Public Services Company, 2020 Integrated Resource Plan, 26 June 2020.
8. Tucson Electric Power Company Arizona Public Services Company, 2020 Integrated Resource Plan, 26 June 2020.
9. Public Service of New Mexico 2020 Integrated Resource Plan
10. Puget Sound 2020 Integrated Resource Plan.

C.4. Resource Adequacy Assessment Process

The basic steps involved in performing a resource adequacy analysis are depicted in Figure C-2. The first step in resource adequacy assessment is to identify the target level of the preferred metric(s) to be achieved. In the second step, probabilistic modeling is used to calculate the expected degree of resource adequacy that will be achieved, based on data and assumptions about the electricity system's supply and demand. The third step compares estimated resource adequacy against a target level of resource adequacy to identify potential shortfalls in expected resource adequacy, and spotlight potential causes and circumstances under which resources will be inadequate. Finally, generation additions, retirements, and other programs can be recommended – often as part of an integrated resource process (IRP) -- to improve resource adequacy.

Figure C-2: Resource Adequacy Process Flowchart



Of the above-noted four steps, the second step involving the quantitative estimation of resource adequacy merits additional discussion here.

Multiple tools are used to conduct resource adequacy modeling in the industry, including spreadsheet-based tools, production cost modeling software, and commercial simulation software tools. For this resource adequacy assessment, an industry-approved probabilistic iterative method using NREL's Probabilistic Resource Adequacy Suite (PRAS) of models was used.

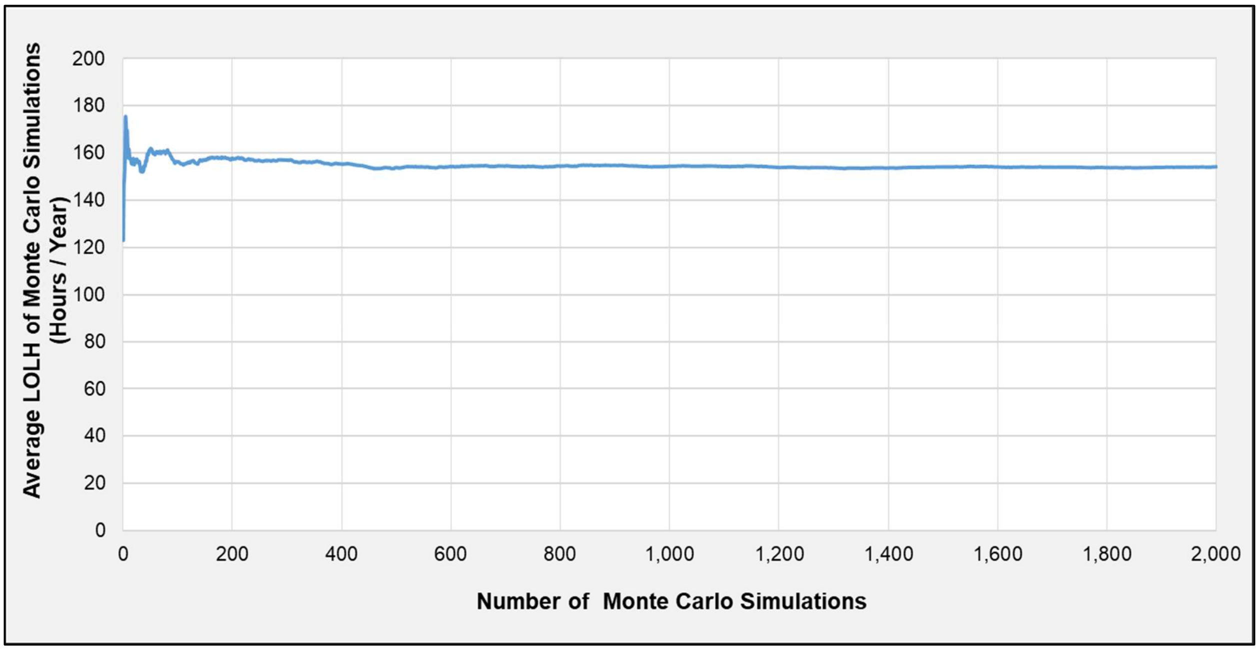
As part of the PRAS model validation, a thorough benchmarking process was undertaken to verify its simulation output relative to the use of other 3rd party production cost and dispatch simulation tools. This validation is documented in Appendix 7 of LUMA's *FY2023 Puerto Rico Electrical System Resource Adequacy Analysis* report. The validation process illustrated strong agreement between the PRAS model and other 3rd party production cost and dispatch simulation tools.

All hours of fiscal year 2025 (FY2025) were simulated in PRAS, calculating whether there will be sufficient available generation capacity to meet load for each hour of the year. Since the timing of power plant forced outages is random, thus randomly affecting when a power plant's will be able to generate electricity in any given hour, each hour of the year is re-simulated multiple times using a statistical technique called Monte Carlo analysis.

With Monte Carlo analysis, each simulation for a given hour involves the application of outage probability at each power plant to arrive at an aggregate resource availability when can then be compared to expected load in that hour. When an hour is simulated many times, with each simulation producing a judgment of resource sufficiency or resource deficit, an estimate of overall probability of resource adequacy in that hour emerges. If the simulation were repeated an infinite number of times, then the true probability of resource adequacy is yielded. However, since it would take an infinite amount of time to computationally estimate anything an infinite number of times, the number of simulations is set at a high but finite number (2,000 simulations) so that the results "converge": the change in estimated resource adequacy measures that result from an additional simulation is miniscule. By evaluating the aggregated results from all simulations after convergence has been achieved, one can quantify the risk (i.e., the probability) of not meeting system load due to resource deficiency.

The following figures help to illustrate the convergence of the PRAS model calculation process. In Figure C-3, the x-axis represents the number of simulations performed, and the y-axis represents the average of estimated loss of load hours (LOLH) over all simulations performed. The blue line suggests that the first simulation produced an estimated LOLH of roughly 122. The second simulation produced a much higher estimated LOLH, such that the LOLH from the first two simulations averaged approximately 175. As more simulations were completed, the average LOLH stabilized around a value of 154 – the final value reported for Base Case LOLH.

Figure C-3: Average LOLH Converges as Number of Iterations Increases



As can be seen in Figure C-3, convergence at an LOLH of 154 is achieved relatively quickly in the calculation process. Rapid convergence is further demonstrated in Figure C-4 below, which plots the change in average LOLH for all completed simulations as additional simulations are performed. As can be seen in Figure C-4, the change in average LOLH falls below 0.1 LOLH approximately 400 iterations into the simulation. At that point, results could generally be considered to have converged. Even so, for additional robustness, an additional 1,600 simulations were completed beyond 400 iterations. All results from the PRAS model presented in this report performed 2,000 iterations.

Figure C-4: Change in Average Estimated LOLH per Subsequent Iteration

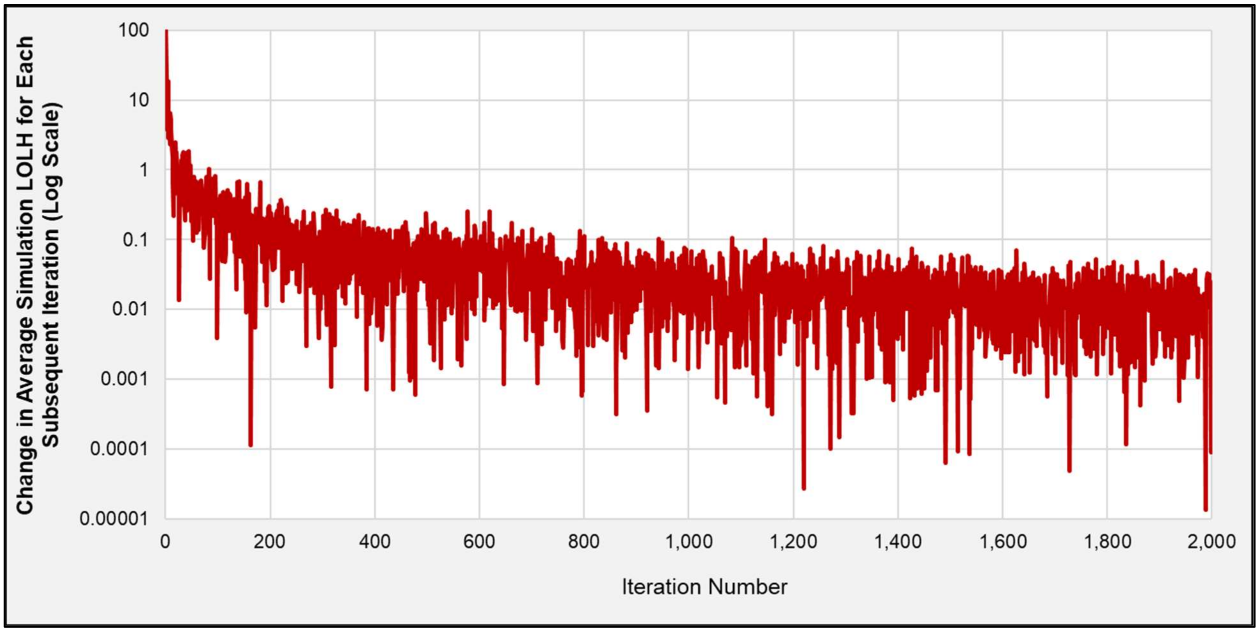
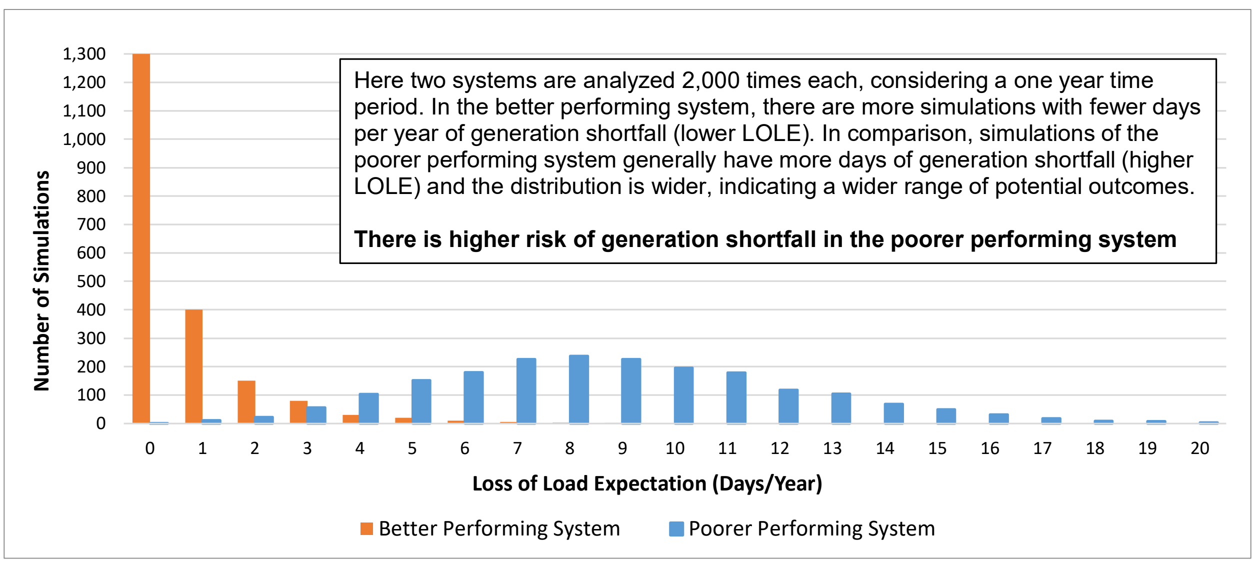


Figure C-5 below helps to illustrate sample results of resource adequacy simulations, presenting the distribution of LOLE output for two electricity systems that are simulated 2,000 times each. As can be seen, the better performing system has more simulations with lower LOLE than the poorer performing system.

Figure C-5: LOLE Probability Distribution for High-Performing and Low-Performing Systems



The above set of steps describe the process for performing a resource adequacy analysis under one set of assumptions about generation supply and demand. However, it is common in resource adequacy studies to perform the above modeling steps under multiple sets of assumptions. This includes estimating the potential impacts on resource adequacy of different "states of the world" (i.e., scenario analysis) as well as evaluating the effects on resource adequacy of an incremental increase or decrease in one narrow aspect of assumptions (i.e., sensitivity analysis).

In this report, in addition to the Base Case scenario that represents an expectation of resource adequacy in FY2025, a Force Majeure Scenario is studied to assess how much Base Case resource adequacy would be harmed by a major natural disaster (e.g., hurricane, earthquake). Further, 20 sensitivity analyses are conducted to illuminate how much Base Case resource adequacy in FY2025 would be affected by isolated changes in the Puerto Rico resource base or electricity demand profile.

C.5 NERC Guidance on Resource Adequacy Practices

Support for probability-based resource adequacy methodologies such as those described above has increased in recent years due to the growth of intermittent (renewable) resources and shifting peak hours for electricity demand, amid other factors. As the primary authority for electricity system reliability in the U.S., the North American Electricity Reliability Council (NERC) has led the advancement of probabilistic resource adequacy practices that better account for these changing conditions facing the electricity industry. While Puerto Rico is not under NERC jurisdiction, as an acknowledged world-leader on resource planning methodologies, Puerto Rico is well-served by taking advantage of NERC guidance on resource adequacy practices.

In March 2011, NERC released a guideline report, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* [22] This report identified the need for alternative approaches rooted in probabilistic analysis when determining variable generation capacity contributions towards availability and resource adequacy. Further, the report recommended the comparison of adequacy study results via the use of additional metrics other than solely PRM.

In 2017, FERC approved NERC Reliability Standard BAL-502-RF-03[23], which created requirements for entities registered as planning coordinators to perform and document resource adequacy analyses. The standard states that a region's PRM should be set such that the average LOLE is equal to 0.10 days per year, a target that has since become widely adopted across the U.S. The standard also provides guidance on matters including load forecast characteristics, resource characteristics, and transmission limitations that prevent delivery of generation reserves in the resource adequacy analysis.

Continuing this expanding resource adequacy guidance, NERC in 2018 released the technical reference report, *Probabilistic Adequacy and Measures* [24] Due to the evolving resource mix landscape resulting from increasing penetration levels of variable generation, this technical reference report focused on identifying, defining, and evaluating more probabilistic approaches and risk measures to provide insights into resource adequacy assessments. Resource evaluation planning approaches profiled in the report range from relatively simple calculations of PRMs to extensive generation resource adequacy simulations that calculate system loss of load probability (LOLP) values.

[22] North American Electric Reliability Corporation, Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning, March 2011.
[23] North American Electric Reliability Corporation, Standard BAL-502-RF-03, October 2017.
[24] North American Electric Reliability Corporation, Probabilistic Adequacy and Measures, July 2018.

Recent NERC surveys[25] indicate that most regions in North America are now using probabilistic approaches to examine resource adequacy questions, and if they are not, they are considering incorporating probabilistic approaches.

C.6. Resource Adequacy and Electric System Resiliency

This document primarily focuses on resource adequacy pertaining to normal system operating conditions. Resource adequacy performance can also be analyzed for adverse operating conditions, such as hurricanes, tropical storms, earthquakes, and other similar disasters. Indeed, this report also includes resource adequacy analysis under a Force Majeure Scenario to estimate the implications on electricity system performance if Puerto Rico is hit in FY2025 by a storm comparable to Fiona.

An industry term typically associated with infrastructure preparedness and performance during and after adverse operating conditions is “resiliency.” White House Presidential Policy Directive 21[26], which focuses on critical infrastructure security and resilience, defines system resiliency as,

> The term ‘resilience’ means the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents.

As such, a resilient system is one that is designed not only to be able to withstand adverse operating conditions, but also to be able to recover quickly. Robust resiliency planning is thus critical to help minimize the negative impacts caused by a high severity event. This is especially true on an island since it is not possible to import electricity from a neighbor in the aftermath of a disaster. While evaluating electricity system resiliency in the face of adverse operating conditions is not a focus of this report, generation resource adequacy is an important part of resiliency planning, and the tools and methodology presented in this report can be used to help quantify the effectiveness of resiliency measures.

Generator and power system resiliency are intricately tied to generation resource adequacy; however, the methodology and assumptions for analyzing resource adequacy for normal operating conditions differ from those tied to analyzing resource adequacy during high severity events. Given high severity events are also often defined by a cascade of system failures, there may be other failures within the electrical system that arise during the event. Failures and challenges (e.g., transmission outages, fuel supply disruptions, flooding) can all place significant stress on the ability of available generators and system equipment to serve load.

It should be noted that a separate work stream addressing electricity system resiliency in Puerto Rico is currently being supported by the U.S. Federal Emergency Management Agency (FEMA).

---

[25] North American Electric Reliability Corporation, Probabilistic Adequacy and Measures, July 2018.
[26] Presidential Policy Directive -- Critical Infrastructure Security and Resilience, The White House, Office of the Press Secretary, February 12, 2013.