March 11, 2021

Public Service Regulatory Board
Puerto Rico Energy Bureau
World Plaza Building
268 Muñoz Rivera Ave.
San Juan, PR 00918

Submitted via email to comentarios@energia.pr.gov

Re: Case No. NEPR-MI-2020-0016

Public Comment of CAMBIO PR and Institute for Energy Economics and Financial Analysis Regarding Modeling and Optimization of Distributed Energy Resources

To the Puerto Rico Energy Bureau:

CAMBIO and the Institute for Energy Economics and Financial Analysis (IEEFA) are filing the attached grid modeling studies for the Bureau's consideration in this Minigrid Optimization proceeding. These studies, commissioned by CAMBIO, evaluated the cost and operation of the Puerto Rico grid under increasing penetration of distributed renewable energy, up to 75% by 2035. This would include equipping 1,000,000 homes in Puerto Rico with a minimum level of household resiliency in the form of a 2.7 kW solar system with battery back-up and incorporating PV systems and storage on roofs and parking lots of commercial establishments. The modeling, which was conducted using PSS/E, PLEXOS and OpenDSS, used electrical system data provided by PREPA.[1]

The studies present an electrical system that is radically more decentralized than what was presented by PREPA in its IRP and in its current 10-Year Infrastructure Plan. The capital investment required by our proposal compares favorably to the more centralized alternatives. To achieve 75% distributed renewable energy by 2035, the study finds that $10.3 billion (in 2020 dollars) of capital investment is required, almost entirely in solar and storage. Only $650 million is required to upgrade the distribution system to integrate distributed renewable energy systems. The studies do not include capital investment that may be required to address critical or urgent repairs or replacements of current infrastructure because data on the current condition of the transmission and distribution infrastructure was not provided to us.

In contrast, we note that the estimated cost of PREPA's mini-grid proposal – which, according to our understanding, is also separate from critical or urgent repairs - has apparently grown from $5.9 billion to

[1] The model has been independently developed by consultants on behalf of CAMBIO and in no way represents any proposal, projection or representation of the Puerto Rico Electric Power Authority.

$8.4 billion since first proposed in PREPA's IRP.[2] PREPA's IRP further proposed over $6 billion in generation capital expenditures over the next 15 years.

We believe that these modeling results can inform the Bureau's Minigrid Optimization proceeding, which seeks to optimize between resiliency solutions based on transmission system hardening versus distributed energy resources.[3] The modeling results show that Puerto Rico could achieve a high level of household and business resiliency by investing in distributed PV and storage systems, with minimal investment required in the distribution system and none in transmission. We believe our approach is also less susceptible to the large construction project capital cost overruns that already appear to be reflected in PREPA's estimates for the transmission-focused alternative. We further note that, based on correspondence between members of the U.S. Congress and FEMA[4], there is no limitation on using federal funding for the resiliency solution we propose.

The agenda of the upcoming technical workshop on March 23rd focuses on DER solutions across the island.[5] We respectfully request that the Bureau either provide us the opportunity to present the findings of this study at the March 23rd workshop or schedule a workshop prior to March 23rd where we may present the findings and address questions from all stakeholders.

Sincerely,

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[2] PREPA, Updated Response to Question 2 of Appendix B, Case No. NEPR-MI-2020-0016, p. 4
[3] Puerto Rico Energy Bureau, Resolution and Order, Case No. NEPR-MI-2020-0016, December 22, 2020.
[4] In a February 8, 2021 letter to Senator Chuck Schumer, the Regional Administrator for FEMA Region 2 wrote, "There are no governing statutes, regulations, or guidance that prohibit Puerto Rico or PREPA from pursuing and proposing power grid projects that support renewable generation and storage in their recovery solutions."
[5] Puerto Rico Energy Bureau, Optimization Workshop #2, February 23, 2021, p. 38.

We Want Sun and We Want More

75% Distributed Renewable Generation in 15 Years in Puerto Rico
Is Achievable and Affordable

Ingrid M Vila Biaggi, MS PE, CAMBIO
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With support from:

Filantropía Puerto Rico

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March 2021

Executive Summary

In 2018, Queremos Sol ("We Want Sun"), a multi-sectoral coalition of Puerto Rican community, environmental and labor organizations, put forward a policy proposal for the renewable energy transformation of Puerto Rico's electrical system under a reformed public ownership model. The proposal emphasized efficiency and distributed renewable energy, particularly rooftop solar and behind-the-meter storage, as a strategy to provide resilience to households in future blackouts, to reduce the impact on agricultural and ecologically valuable lands from utility-scale renewable energy projects, and to reduce the island's dependence on imported fossil fuels and extensive transmission systems. Queremos Sol proposes a transformation that is equitable, affordable and that ensures a transition to renewables that is fair to PREPA workers.

In this report, we summarize the result of in-depth grid modeling studies completed in early 2021 to investigate specific technical aspects of the Queremos Sol proposal. Specifically, Telos Energy and EE Plus performed modeling of the Puerto Rico Electric Power Authority's generation, transmission and distribution infrastructure, using data obtained from PREPA, to analyze scenarios of increasing penetration of renewable energy, up to 75% (with over half of that from residential installations) of total electricity consumption by 2035. Energy Futures Group used these grid modeling results to estimate costs. Key results of this analysis are:

- Achieving 75% distributed renewable energy generation in 15 years is feasible with minimal upgrades to the distribution system.
- Equipping 100% of homes with 2.7 kW PV and 12.6 kWh battery backup can provide 2700 MW of power to the Puerto Rico grid, which would need to be supplemented by solar installations at commercial sites (rooftops and parking lots) to reach 75% renewable energy penetration.
- Seventy-five percent distributed renewable energy by 2035 would cut imported fossil fuel costs to $430 million/year (relative to recent expenditures over $1.4 billion/year) and reduce carbon dioxide emissions by more than 70%.
- The distributed energy scenarios demonstrate there is no need for new fossil fuel generation or conversions of existing units to natural gas. It is possible to move directly to the widespread deployment of distributed solar and storage technologies, rather than locking in decades of new natural gas infrastructure.

- Under the 75% distributed renewable energy scenario, the vast majority of PREPA's current power plants would no longer be used, included the AES coal plant, which can be retired in the next 4 years.[1]
- The 75% distributed renewable energy scenario is less expensive than the base case of PREPA's current grid.

Puerto Rico's future electric rates face significant uncertainty due to federal funding, privatization contracts and PREPA's ongoing debt restructuring. Without including legacy debt, the 50% and 75% distributed energy scenarios modelized here result in average system costs equal or less than 20 cents per kWh. The study does not assume any specific ratemaking policy. **If $9.6 billion in federal funding is used to cover necessary distribution system improvements and to invest in distributed solar and battery systems as proposed by Queremos Sol and modeled, the average system cost is less than 15 cents/kWh in 2035.** Moreover, Puerto Rico's dependency on fluctuating fossil fuel prices would be dramatically reduced providing greater stability in rates.

After the 2017 hurricanes, high-level rhetoric has emphasized transitioning to a renewable energy-based, resilient electrical system, while money has flowed to privatization, centralized generation and natural gas infrastructure. Most recently, PREPA's 10-Year Infrastructure Plan calls for spending about $10 billion in federal funds to harden PREPA's centralized transmission and distribution systems and to build out new natural gas infrastructure, with zero dollars directed towards renewable energy and storage. Decisions over the use of billions of dollars in federal funding will shape Puerto Rico's grid for decades to come.

A distributed energy future for the island is technically achievable, affordable and would provide real resiliency to Puerto Rico homes and businesses. In this report, we make the case for policy development and prioritization of federal funding to widely deploy rooftop solar and storage, coupled with energy efficiency, across Puerto Rico.

[1] Retirement of AES modeled follows substitution of its generation capacity with roof-top solar and PV. However, Queremos Sol's demand for immediate retirement of AES can also be attained through other operational modifications.

Background

The future of Puerto Rico's oil-dependent, poorly maintained and bankrupt electrical system has been highly contested. In the aftermath of Hurricanes Irma and Maria in 2017, this debate received much greater attention island-wide and in the continental United States. At a high level, there has been significant recognition of the role that distributed renewable energy could play in enhancing resiliency.

Law 17-2019, Puerto Rico's Energy Public Policy Act envisions an electrical system "that empowers the consumer to be part of the energy resources portfolio through the adoption of energy efficiency strategies, demand response, the installation of distributed generators."[2]

However, in the three years since the hurricane, distributed energy resources have not played a central role in the transformation process, which continues to perpetuate a centralized generation model.

PREPA's twenty-year Integrated Resource Plan (IRP) - the long-term plan for the island's generation system approved by its regulator, the Puerto Rico Energy Bureau – is supposed to be the guiding document for investments in the generation system.[3] PREPA's IRP was based on electric generation capacity expansion modeling that evaluated the cost of adding new capacity and retiring existing capacity to arrive at the least-cost trajectory for transforming the island's generation mix. However, the capacity expansion model was not capable of simulating distribution system investments and simply assumed a certain penetration of rooftop solar resources (13% by 2035[4]). While this is common practice in integrated resource planning in the continental United States, it is an impediment to achieving the desired widespread penetration of distributed energy resources in Puerto Rico.

Additionally, despite the alleged primacy of the IRP in guiding the development of Puerto Rico's electrical system, investments in the generation system have moved forward outside of the IRP process. Notably, PREPA entered into a contract with New Fortress Energy subsidiary NFEnergia for the conversion of units 5 and 6 of the San Juan power plant to natural gas and for a five-year supply of natural gas (with possible extension up to 20 years).[5] The deal has been criticized for its lack of clarity on savings to ratepayers, for taking place outside of the IRP process, for NFE's failure to gain approval from the Federal Energy Regulatory Commission for its project, for failing to notify and consult neighboring communities, and for numerous red flags in the contracting process itself.[6]

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[2] Act 17-2019, Article 1.5(2)(e).

[3] Act 57-2014, Article 6.23.

[4] PREPA's workpaper for the Energy System Modernization scenario (its preferred IRP scenario) in 2035 shows 1,508 GWh of customer-owned PV generation out of a total generation of 11,780 GWh. (See PREPA file "ESM_Metrics_Base_SII-mm with action plan tab" filed with the Puerto Rico Energy Bureau in Case No. CEPR-AP-2018-0001 on June 28, 2019).

[5] Gerardo E. Alvarado León, "La AEE y NFEnergía firman contrato de combustible," El Nuevo Día, March 5, 2019.

[6] Tom Sanzillo and Ingrid Vila-Biaggi, "Is Puerto Rico's Energy Future Rigged?", Institute for Energy Economics and Financial Analysis, June 2020.

Most recently, PREPA has earmarked federal funding to build new natural gas infrastructure that was rejected by the Energy Bureau in the IRP proceeding. Specifically, PREPA plans to spend over $500 million in federal funds to construct a 400 MW natural gas plant near San Juan in 2024, despite the fact that this was not approved in the IRP.[7] PREPA does not plan to spend any FEMA grid reconstruction funds on renewable energy or storage.

The laws passed by the Puerto Rico legislature since Hurricane Maria are aimed primarily at privatizing the electrical system (Law 120-2018 and Law 17-2019). These laws set up a streamlined and non-transparent process for the lease of PREPA's T&D system to a private operator and for the sale or lease of generation assets to private buyers. In the absence of clear prioritization of distributed renewable energy, this legislation has facilitated natural gas interests (like NFEnergia) pushing centralized natural gas infrastructure in Puerto Rico.

Finally, ongoing negotiations with PREPA's creditors to restructure PREPA's $9 billion in legacy debt are likely to have a material impact on future investment in the electrical system. The most recent debt restructuring agreement (RSA) seeks to recover legacy debt from a surcharge on rates for the next 47 years. The debt charge, which grows to 4.552 cents/kWh over that period, would also be applied to electricity generated by distributed solar panels installed after September 2020.[8] This structure thwarts the goal of incentivizing distributed generation on the island. As of February 2021, the RSA has not received court approval because the 2020 earthquakes and pandemic have dramatically worsened economic conditions in Puerto Rico.

In short, the transformation process post-hurricane Maria has been fraught with contradictions that, so far, have furthered more of the same: politically-driven contracting focused on centralized generation, particularly natural gas. Yet there is still much that is uncertain about the future of the power system. PREPA's proposals for new natural gas infrastructure were largely rejected by the Energy Bureau in its latest IRP, despite PREPA's ongoing attempts to circumvent the Bureau. The outcome of debt restructuring negotiations are still uncertain. The recent concession of PREPA's operations (excluding generation) to a private third-party has drawn stiff opposition. The imminent disbursement of over $10 billion in FEMA funds for the electrical system, plus the potential future disbursement of nearly $2 billion in HUD funds, will shape the grid for decades to come.[9]

Queremos Sol Modeling Initiative

In this context, Queremos Sol ("We Want Sun"), a multi-sectoral coalition of Puerto Rican community, environmental and labor organizations, put forward a policy proposal for the renewable energy transformation of Puerto Rico's electrical system under a reformed public ownership model in 2018. Queremos Sol explicitly rejected the push for privatization of the electrical system and centered energy efficiency and distributed renewable energy in its vision.

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[7] See: Puerto Rico Electric Power Authority, Revised 10-Year Infrastructure Plan, February 2021. And Puerto Rico Energy Bureau, Final Resolution and Order, Case No. CEPR-AP-2018-0001, August 21, 2020, paragraph 620.

[8] Definitive Restructuring Support Agreement, May 3, 2019. (See Appendix C: Recovery Plan Term Sheet).

[9] José Delgado, "FEMA aprueba cerca de $13,000 millones para reconstruir la red eléctrica y el sistema educativo," El Nuevo Día, September 18, 2020.

The vision included specific goals of 25% energy efficiency by 2035, 50% renewable energy by 2035 and 100% by 2050. Queremos Sol specifically advanced the proposal of providing 75% of homes in Puerto Rico with a minimum level of energy security, in the form of solar with battery back-up, by 2035. Queremos Sol also rejected the development of new natural gas infrastructure on the island.[10]

In this report, we present the results of modeling conducted on behalf of CAMBIO to lend more analytical detail to the Queremos Sol proposal. A key focus of this modeling was analyzing the costs and technical operations of a grid heavily based on decentralized renewable energy (rooftop solar and storage). As noted above, this type of modeling was absent from PREPA's most recent IRP. The modeling analyzed three scenarios of increasing penetration of decentralized renewable energy to find out what that would mean in terms of: (a) generation mix; (b) costs; and (c) upgrades required to maintain grid stability and reliability.

The modeling was conducted by Telos Energy and EE Plus, using data provided to CAMBIO and the Institute for Energy Economics and Financial Analysis (IEEFA) as a result of a public records request.[11] Energy Futures Group used these grid modeling results to estimate costs. The modeling evaluated four scenarios for the Puerto Rico grid in 2035: a base case scenario that projects today's grid and generation mix into 2035, and three scenarios with increasing levels of renewable energy penetration. As shown in Table 1, these scenarios meet 25, 50 and 75% of Puerto Rico's assumed 2035 electricity consumption with renewable energy and assume that 50, 75 and 100% of residential homes are equipped with 2.7 kW solar panels and 12.6 kWh battery backup, respectively.[12]

Table 1: Summary of Renewable Energy Scenarios[13]

		25% DPV	50% DPV	75% DPV
Renewable Share	% of Total Generation	25%	50%	75%
Resilient Homes	% of Resilient Homes	50%	75%	100%
Distributed PV Capacity (MW)*	Residential	1,350	2,025	2,700
	Commercial	143	1,212	2,282
	Total	1,493	3,237	4,982
Distributed BESS Capacity	Power Rating (MW)	1,178	1,853	2,528
	Energy Rating (MWh)	5,301	8,339	11,376
	Duration (hrs)	4.5	4.5	4.5

*Includes existing distributed PV

[10] For more details, see queremossolpr.com

[11] Although data used was provided by PREPA the model has been independently developed by consultants on behalf of CAMBIO and in no way represents any proposal, projection or representation of the Puerto Rico Electric Power Authority.

[12] 100% of homes refers to 1,000,000 homes that are projected to be inhabited by 2035. Multi-family units, or houses where PV installation is not possible, are assumed to be served by nearby home, community or commercial installations.

[13] Telos report, Table 1.

These scenarios were evaluated using a production cost model (PLEXOS) that optimized the use of generation resources on the grid in each scenario, according to assumptions about solar availability, fuel prices, and operations and maintenance costs for each generating unit. The full details of this analysis are found in the report of Telos Energy (hereafter "Telos report"). Telos also ran a transmission model (PSS/E) that simulated the flow of power on PREPA's transmission network in each scenario. This showed how the integration of increasing amounts of distributed renewable energy changes PREPA's traditional reliance on south-to-north transmission lines to bring power from generators in the south to population centers in the north. It also provided an opportunity to analyze the stability of the grid under increasing amounts of renewable energy systems, which do not respond to disruptions to the grid (generator or transmission outages) in the same way as traditional fossil fuel-based generators.

EE Plus used the transmission system power flow modeling output from the Telos analysis to model power flows on the distribution system using OpenDSS. EE Plus analyzed 976 feeders (89% of PREPA's distribution system mileage) to determine which distribution lines would need to be rebuilt or reconductored in order to accommodate increasing amounts of rooftop solar interconnected directly to the distribution system.

Energy Futures Group analyzed the energy efficiency measures that could be used to meet Queremos Sol's vision of 25% energy efficiency by 2035 and forecasted the 2035 island-wide electricity demand that was input into the Telos and EE Plus modeling. Energy Futures Group also modeled the total costs of each scenario, including the costs of acquiring the solar and battery storage resources.

Modeling Results

No New Natural Gas Infrastructure Is Needed to Achieve High Penetrations of Renewable Energy

The modeling analysis conducted here shows that it is possible to skip over natural gas as a "bridge fuel" and move directly to the widespread deployment of distributed solar and storage technologies, rather than locking in decades of new natural gas infrastructure. The modeling shows there is no need for the construction of any new natural gas infrastructure or for the conversion of existing plants to gas. In contrast, the integrated resource plan (IRP) presented by PREPA to the Energy Bureau included substantial investment in new natural gas infrastructure. Although many of these proposals were rejected by the Bureau, the Bureau did authorize PREPA to move forward with preliminary permitting activities and studies for a 300 MW natural gas plant at Palo Seco and also stated that it would consider the conversion of the AES coal plant to natural gas as part of the next IRP cycle.[14] Moreover, PREPA's 10-Year Infrastructure Plan also calls for the use of FEMA funding to build new natural gas infrastructure, although the

[14] Puerto Rico Energy Bureau, Final Resolution and Order, Case No. CEPR-AP-2018-0001, August 21, 2020, p. 284.

Bureau has ordered PREPA not to move forward with implementation of this initiative beyond $5 million for preliminary studies.[15]

The Scenarios Allow for the Retirement of the AES Coal Plant and Varying Amounts of Oil and Natural Gas Capacity

In the modeled scenarios, increasing amounts of distributed renewable energy displace the current fossil-based generation and allow for the retirement of existing units. Telos used a weighted ranking – that included age, cost, emissions, flexibility, forced outage rate, and location – to prioritize units for retirement.

The 25% DER scenario allows for the retirement of the AES coal plant and Palo Seco units 3 & 4.[16] If pursued starting in 2021, this scenario can be attained by 2024. The 50% DER scenario allows for the additional retirement of the Aguirre steam units 1 & 2. And the 75% DER scenario allows for the additional retirement of the Aguirre combined cycle plant, for a total of 2,306 MW of conventional generation retired. This is shown in the following table:

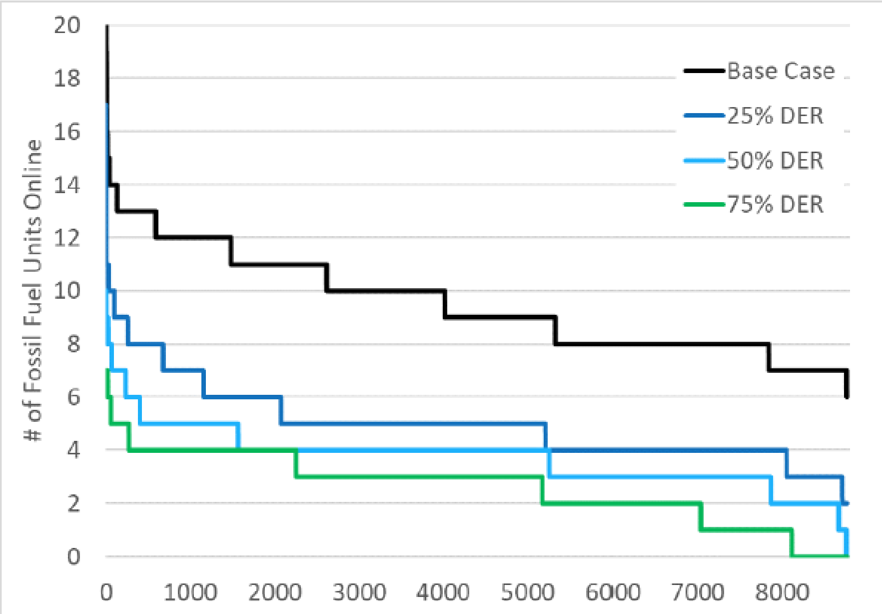
Table 2: Unit Retirements Under Distributed Renewable Energy Scenarios[17]

Case	Units Retired	Incremental Capacity (MW)	Cumulative Capacity (MW)
Base Case	Not Applicable	0	0
25% DER	AES 1 & 2 and Palo Seco Steam 3 & 4	886	886
50% DER	Aguirre Steam 1 & 2	900	1,786
75% DER	Aguirre CC 1 & 2	520	2,306

It is worth noting that in the 75% DER scenario, the majority of the fossil generation units remaining on the system are rarely, if ever, used. As shown in the following figure, a maximum of 7 fossil generating units (out of a current total of 39) are generating power during the 75% DER scenario. A more detailed resource adequacy analysis could likely identify additional units that could be retired.

[15] PREPA, "Response to Resolution and Order Entered on January 25, 2021 and Request for Approval of Revised 10-Year Infrastructure Plan," Puerto Rico Energy Bureau Case No. NEPR-MI-2021-0002, February 16, 2021.
[16] Retirement of AES modeled follows substitution of its generation capacity with roof-top solar and PV. However, Queremos Sol's demand for immediate retirement of AES can also be attained through other operational modifications.
[17] Telos report, Table 2

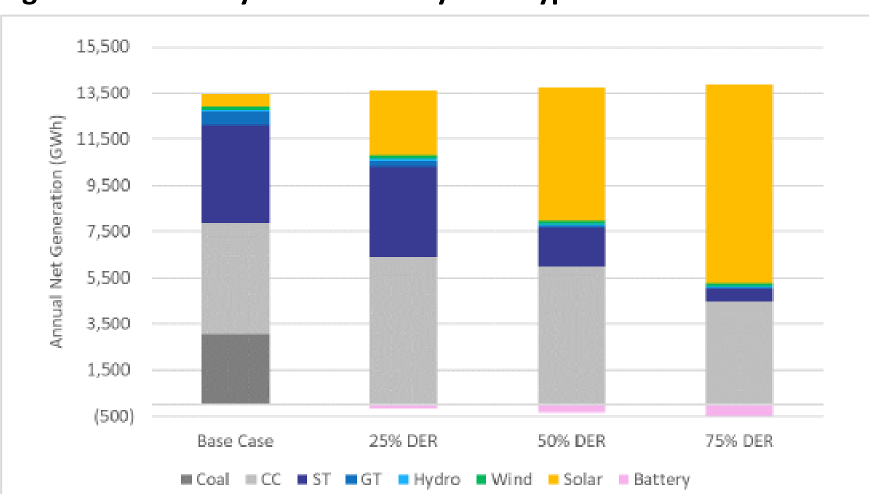
Figure 1: Number of Fossil Fuel Units Generating Power Per Hour of the Year in 2035[18]



Decreased reliance on PREPA's unreliable power plants, which are a frequent cause of power outages, also provides a reliability benefit for the distributed energy scenarios.

Figure 2 shows Puerto Rico's energy generation mix under the modeled scenarios. There is no coal generation in any of the DER scenarios since the AES coal plant is retired. The natural gas- and oil-fired units (blue and light grey bars) initially increase to compensate for some of the lost coal generation, but are ultimately partially displaced by solar. In the 75% DER scenario, both oil and natural gas consumption have declined by more than 50% relative to the current grid. The San Juan 5 and 6 units were modeled as operating with fuel oil in 2035.

Figure 2: Electricity Generation by Fuel Type in 2035[19]



[18] Telos report, Figure 30

[19] Telos report, Figure 15.

The amount of renewable energy resources built out in the 75% DER scenario is comparable to the S3S2B scenario in PREPA's IRP, which was the most aggressive renewable energy scenario that PREPA analyzed for implementation over a 20-year period. The 75% DER scenario achieves 8,802 GWh of renewable energy generation, over half of which is from residential rooftop installations.[20] The S3S2B scenario presented by PREPA achieves 7,613 GWh of utility-scale renewable energy and 1,508 GWh of residential rooftop solar by 2035.[21] The key difference is that the 75% DER scenario is based on distributed resources rather than utility-scale solar generation and therefore provides a much greater level of household-level resiliency and reduced dependency on transmission.

The Modeled Scenarios Cut Puerto Rico's Imported Fuel Bill by Close to $600 Million per Year

As a result of the decreased reliance on fossil fuels, Puerto Rico is able to dramatically decrease its bill for imported fossil fuels (i.e. all fossil fuels) across the modeled scenarios. Table 3 shows total operating costs (not including capital costs) for the fossil fuel units across all of the scenarios. Using modeled 2035 fuel prices from PREPA's integrated resource plan, the distributed energy scenarios save close to $600 million in fuel costs in 2035 relative to Puerto Rico's current grid. The 75% renewable energy by 2035 scenario would cut imported fossil fuel costs to $432 million/year (relative to recent expenditures over $1.4 billion/year)

Table 3: Costs of Operating Fossil Fuel Units in Each Scenario[22]

Case	Base	25% DER	50% DER	75% DER
Fuel Costs	$1,003	$926	$677	$432
Fixed O&M + Cap. Maint.	$255	$198	$151	$130
Variable O&M	$59	$32	$21	$13
Startup Costs	$24	$31	$34	$28
Total Costs	**$1,341**	**$1,188**	**$883**	**$603**

Distributed Energy Scenarios Both Reduce Puerto Rico's Contribution to Climate Change and Enhance Resilience to Future Storms

By 2035, the 75% DER scenario results in a 70% reduction in carbon dioxide emissions relative to the base case from 8.9 million tons per year to 2.6 million tons per year. [23] This is a direct result of reduced consumption of fossil fuels.

At the same time as the much greater reliance on distributed renewable energy reduces Puerto Rico's contribution to climate change, it also greatly enhances household resiliency to more severe storms. In the 75% DER scenario, all households have a 2.7 kW rooftop solar system with

[20] See Table 17 of Telos report.
[21] PREPA IRP workpaper "S3S2B_Metrics_Base_SII" filed with the Puerto Rico Energy Bureau in Case No. CEPR-AP-2018-0001.
[22] EFG Report, Table 12.
[23] Telos report, p. 38.

12.6 kWh battery storage to serve critical loads, providing continued access to electricity even if the transmission system is severely damaged by a hurricane.

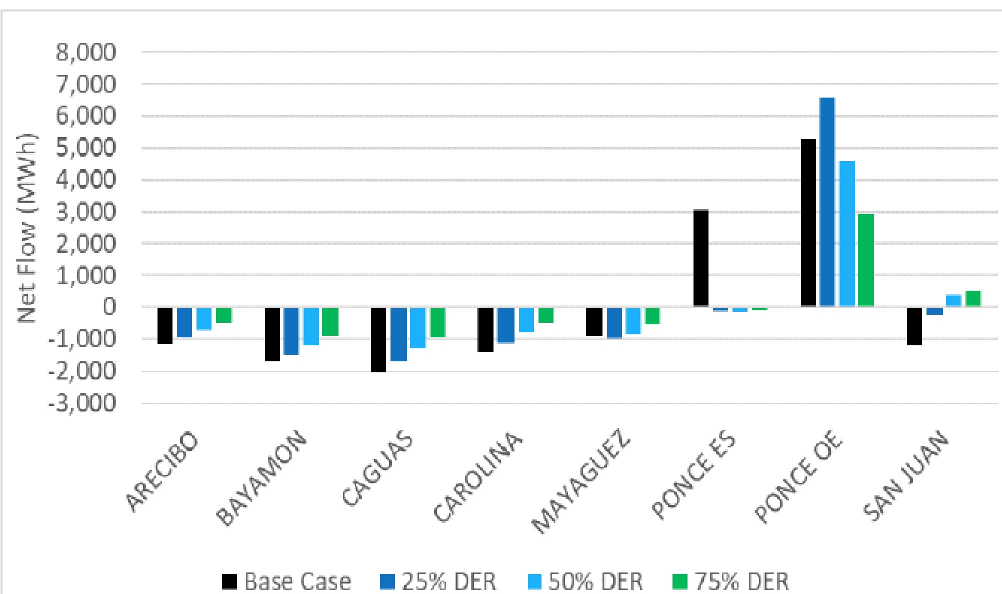
The strategy pursued by Queremos Sol and modeled here would place Puerto Rico at the forefront of worldwide climate change mitigation objectives while adopting a cost-effecting approach to much needed adaptation, in order to reduce vulnerabilities.

Increased Reliance on Distributed Renewable Energy Dramatically Reduces Reliance on South-To-North Transmission

One of the vulnerabilities of Puerto Rico's current grid configuration, which was dramatically exposed by hurricane Maria, is its over-reliance on south-to-north transmission because the majority of the power plants are located in the south and the main population center (the San Juan metropolitan area) is in the north. This is shown in Figure 3, where the black bars (the current grid configuration) show large net power flows out of the two Ponce transmission zones located along the south coast.

In the modeled scenarios, solar is distributed evenly across the island's eight transmission zones, roughly proportional to population within each zone. As a result of the location of more power generation in the north, power imports decline across all of the northern transmission zones (Arecibo, Bayamon, Carolina, and San Juan). Power export declines dramatically out of the eastern Ponce zone ("PONCE ES") because of the retirement of the AES coal plant in all DER scenarios. Power export actually increases out of the western Ponce zone ("PONCE OE") to compensate for the AES retirement in the 25% DER scenario, but then power exports decrease as more distributed solar is integrated to the grid.[24]

Figure 3: Net Annual Flow of Power Out of Each Transmission Zone[25]



[24] Telos report, pp. 40-41.

[25] Telos report, Figure 22.

Energy Efficiency Programs Can Be Scaled to Meet 25% of Puerto Rico's Demand by 2035

Energy Futures Group identified several areas where energy efficiency programs could be scaled to meet the goal of meeting 25% of projected 2035 electricity demand through energy efficiency. However, EFG's projection of 2035 sales does not depend entirely on specific energy efficiency programs. Efficiency gains are a combination of: natural energy efficiency (savings that occur without additional policy intervention through the tightening of appliance energy efficiency standards); energy efficiency programs administered by the utility; and the conversion of 70% of residential electric water heaters to solar water heaters.[26] Utility-sponsored energy efficiency programs include incentive programs to improve the efficiency of residential lighting, residential air conditioning, commercial lighting, commercial refrigeration, commercial lighting controls and more.[27]

Operational Changes to Achieving 75% Renewable Energy Grid by 2035 Can Be Addressed

One of the critical results of the Telos study is that achieving high levels of distributed renewable energy penetration (75%) on the Puerto Rican grid is technically feasible by 2035. Solar is different from traditional power plant generation in that it is only available when the sun is shining. The addition of batteries allows solar power to be stored for use to meet electricity demand at other times. But even so, solar plus battery storage at high levels of penetration changes grid operations. The Telos study explored these changes at length, modeling how a grid with increasing amounts of distributed renewable energy would respond to different disruptive events like a generator outage or a transmission line fault. The study identified mitigation options, including introducing Fast Frequency Response (FFR), synchronous condensers, and grid forming inverters, to result in a reliable grid with 75% renewable energy penetration by 2035.

Little Investment in the Distribution System Is Required to Achieve High Levels of Renewable Energy Penetration; No Investment Required in Transmission

The EE Plus study modeled 89% of the distribution system including Vieques and Culebra. It identified distribution feeder lines that would need to be rebuilt or reconductored in order to avoid overheating of lines and equipment, and to maintain voltages within the needed range, in the distribution system as a result of integrating renewable energy generation at the distribution level. In the 75% DER penetration scenario, this analysis found that 4,504 miles of distribution lines would need to be reconductored or rebuilt (about 14% of the total line-miles

[26] EFG Report, p. 7-8.

[27] The baseline load forecast assumed for modeling is slightly higher than what PREPA assumed in its integrated resource plan. This modeling assumed, before accounting for energy efficiency, 0% growth in sales by 2035, whereas the IRP modeled a 4% decline in sales by 2038. (Puerto Rico Energy Bureau, Final Resolution and Order, Case No. CEPR-AP-2018-0001, August 21, 2020, p. 47).

of Puerto Rico's distribution system), and 149 MVA of transformers upgraded.[28] The cost of these upgrades are estimated in Table 4.

Table 4: Cost of Distribution System Upgrades in 75% DER Scenario[29]

Scenario	Transformer Upgrade Cost	Line Reconductor Cost	Line Rebuild Cost	Total Cost
Base	$0	$41,141,424	$243,592,659	$284,734,084
25% DER	$0	$77,545,581	$455,887,200	$533,432,781
50% DER	$2,410,800	$76,269,071	$516,119,531	$594,799,403
75% DER	$7,330,800	$97,837,352	$546,739,997	$651,908,149

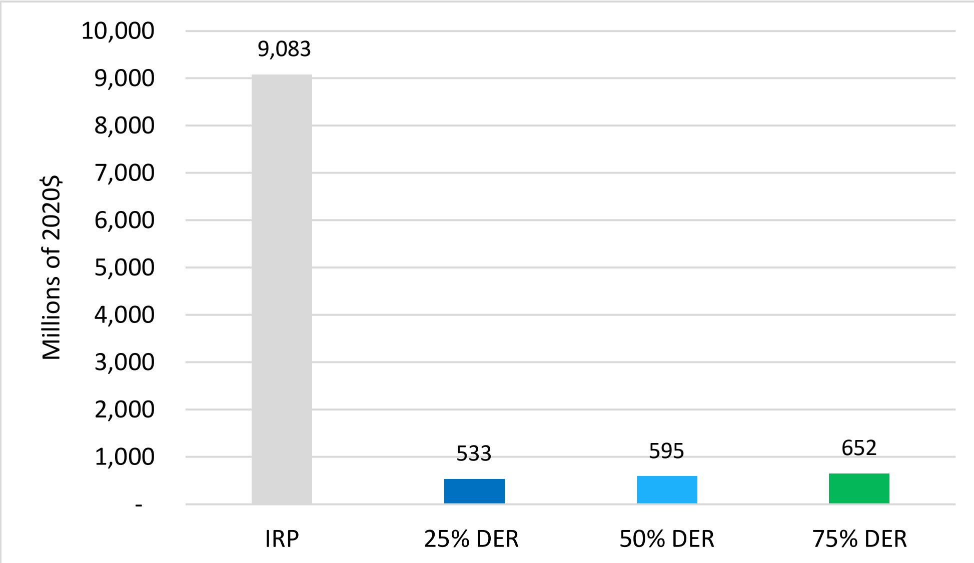
Two factors contribute to the relatively low level of distribution system improvements needed to integrate this high level of distributed generation. One is the fact that highly distributed, rooftop systems allow for a large amount of generation to be consumed on site, minimizing use of the distribution system. The second is the coordinated deployment of rooftop solar with battery storage, which helps to minimize impact on system voltage.[30]

No additional upgrades to the transmission system were identified in the Telos study for integration of renewables.

These levels of transmission and distribution system investment are much lower than proposed by PREPA in its most recent integrated resource plan. PREPA's IRP devoted more than $5 billion to its minigrid concept. Beyond this, the IRP included over $3 billion for hardening of existing infrastructure and bringing it up to standards. Because we lacked data on the current condition of distribution system assets, the EE Plus study does not include costs to bring this infrastructure up to standard. It may be that at least some of the $3+ billion in upgrades and urgent improvements of existing transmission and distribution system infrastructure are needed. Even with such costs included, transmission and distribution system capital investments would still be over $5 billion less than proposed by PREPA in its IRP.

[28] EE Plus report, p. 22.
[29] EFG report, Table 10.
[30] EE Plus report, p. 5.

Figure 4: Total Transmission & Distribution System Capital Costs[31]



Investment in Solar and Storage Required to Achieve High Penetrations of Distribution Renewable Energy Is Comparable to Generation System Investment Proposed by PREPA for a Centralized System

Even though the high distributed energy scenarios require significant capital investment in PV and battery storage technologies, total capital costs in those scenarios are still comparable with capital investment in new generation proposed by PREPA in its IRP. Figure 4 compares the total amount of generation system capital investment in each DER scenario to PREPA's preferred scenario in its IRP. Note that PREPA's IRP did not include the cost of the 848 MW of distributed solar that it assumed customers would install; adding that cost would raise the cost of the IRP scenario by roughly $1 billion to over $7.5 billion.

On the other hand, as mentioned earlier there is a dramatic difference in investment proposed for distribution and transmission by PREPA and the investment required in the 75% scenario. When adding all components (generation, transmission & distribution), Figure 6 shows that even the 75% scenario of distributed renewable generation is over $5 billion less than PREPA's preferred IRP scenario.

[31] EFG Report, Figure 14.

Figure 5: Total Generation System Capital Costs, 2020-2035[32]

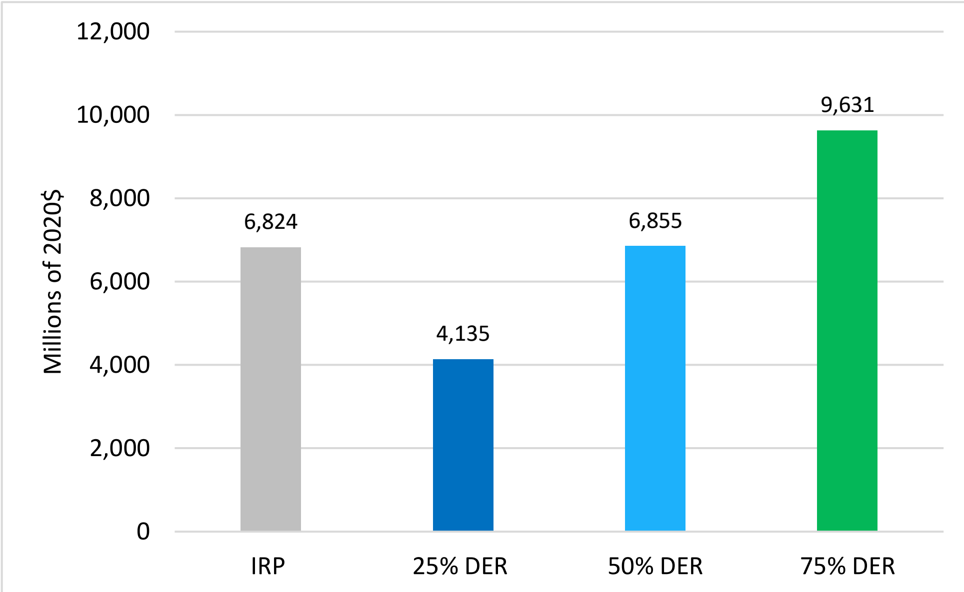
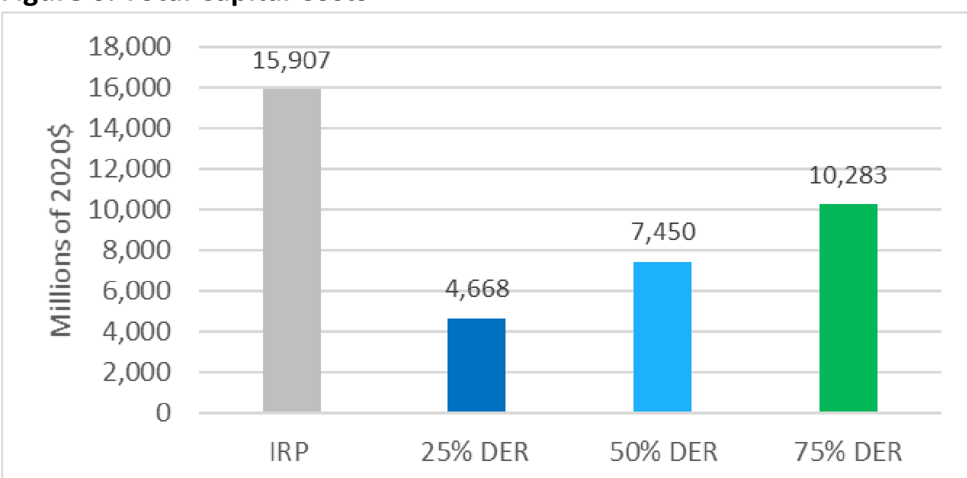


Figure 6: Total Capital Costs[33]



Overall 2035 Costs Are Lower in the 75% DER Scenario

Figure 7 shows the total costs of the scenarios in 2035, including both operational costs and the annualized cost of solar and battery storage systems. The base case includes no capital costs for new generation which represents a conservative approach. Capital costs are modeled assuming a 6.5% cost of capital, an estimate that assumes that PREPA is responsible for financing of solar and battery storage systems.[34] The figure also includes a carbon cost to take into account the climate change damage caused by burning fossil fuels. Including carbon costs, all of the DER

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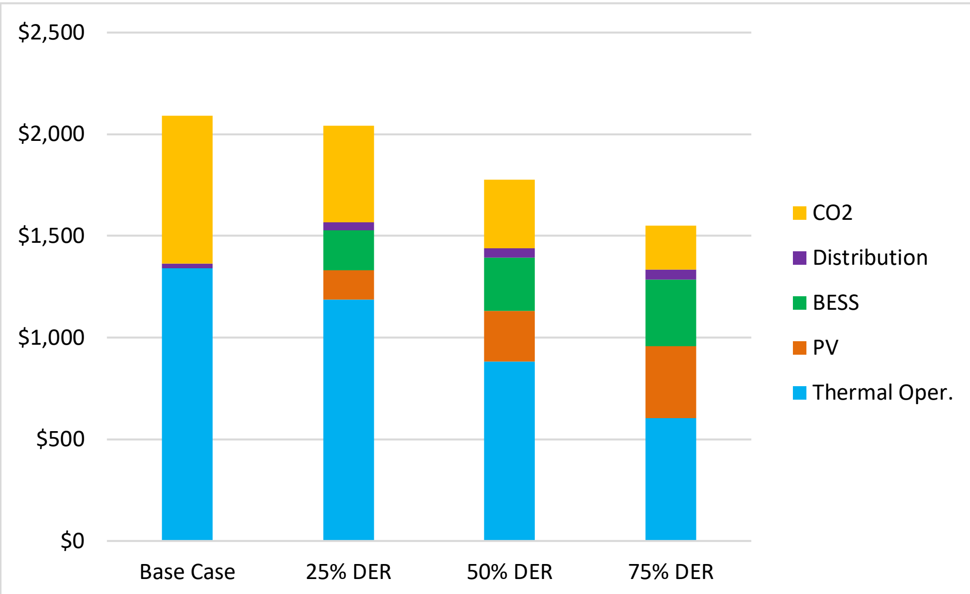
[32] Source: EFG Report, Figure 12.

[33] Fuente, Informe EFG

[34] PREPA's most recent long-term debt issuances prior to bankruptcy had interest rates in the 5-7% range. EFG modelled financing costs using a value that was conservatively high compared to the interest rates faced by other public power utilities.

scenarios are progressively less expensive than the base case. Even without the carbon cost, and without capital costs for new generation in the base case, the 75% DER cost scenario is slightly less expensive than the base case, as increasing capital costs are balanced by declining fuel import costs.

Figure 7: Total System Costs (Millions of 2020$) in 2035[35]



Impact on Electric Rates

To evaluate the affordability of these scenarios, we derived an estimate of the electric rate in each DER scenario in 2035. Generation costs shown in Figure 8 include thermal unit operational costs and the annualized capital costs for PV and storage, assuming that PREPA finances the installation of these systems.[36] Non-generation costs are based on PREPA's certified FY 2021 budget, but excluding costs related to the privatization of the system and to PREPA's bankruptcy process, under the assumptions that PREPA remains a public utility and emerges from bankruptcy well before 2035.[37] The non-generation system costs also include the annualized cost of financing the distribution system capital upgrades identified in the EE Plus study. We further include a scenario in which Puerto Rico is able to direct $9 billion in grid reconstruction funding towards distributed energy resources and $650 million to distribution

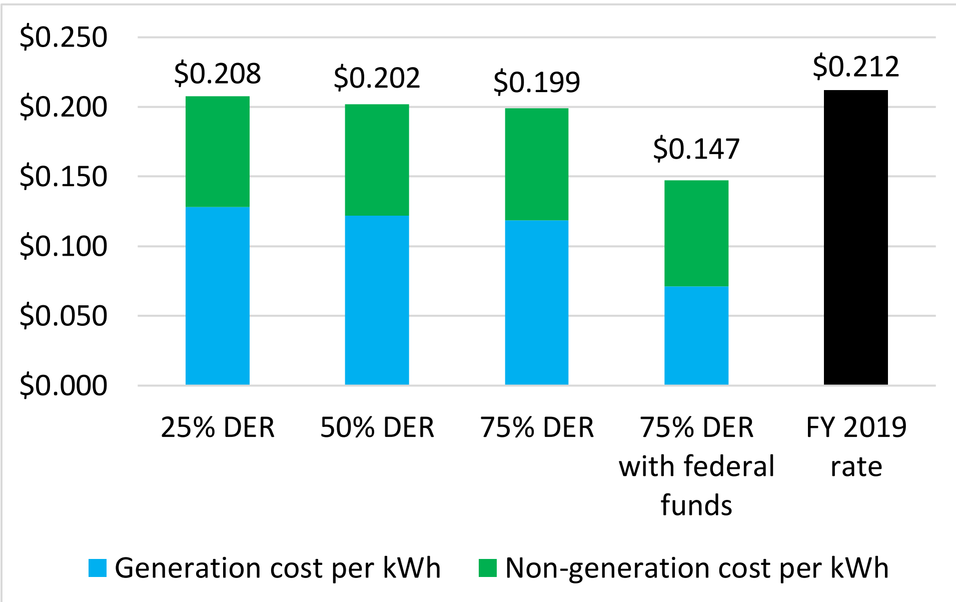
[35] EFG Report, Figure 6.

[36] Our analysis assumes that PREPA customers in 2035 are paying the debt service on prior years' installations. As a sensitivity, we analyzed the impact on rates if PREPA finances these installations at 8.5%, not 6.5%. In that case, the cost of the 75% DER scenario only increases by about 1 cent to 21.1 cents/kWh.

[37] Specifically, our non-generation cost estimate is derived from PREPA's FY 2021 Certified Budget. Labor costs were adjusted based on the ratio of non-generation to total employees. Generation maintenance expenses as well as line items for "PREPA Restructuring & Title III," "FOMB Advisor Costs allocated to PREPA", "P3 Authority Transaction Costs" and "T&D Operator Costs" were also excluded. Finally, we included an estimate of energy efficiency program costs based on PREPA's IRP modeling.

system upgrades to achieve the 75% DER scenario.[38] We arrive at total system costs at or below 20 cents per kWh in the 50% and 75% DER scenarios, and below 15 cents/kWh in the scenario with federal funding. It is worth noting that 20 cents per kWh is the rate set as desirable target in PREPA's Fiscal Plans and defined in the Preamble of Law 17-2019.

Figure 8: Average Costs in 2035 per kWh (in 2020 dollars)



These scenarios compare favorably with recent PREPA rates, shown in the black bar in Figure 7. We emphasize that electric rates in the DER scenarios will be much less subject to fuel price volatility than current rates.

It is worth highlighting that the scenarios evaluated for modeling were never cost-optimized. That is, the scenarios were developed to explore the operation of the Puerto Rico grid at pre-defined high levels of distributed renewable energy penetration, with renewable energy and household resiliency goals in mind. They were not developed to minimize total system cost (and decisions about which units to retire included factors such as emissions rates, age, flexibility and location, in addition to cost). Therefore, it is particularly significant that we find that the high-penetration DER scenarios are affordable, as defined by Law 17-2019.

It is also important to note that the non-generation costs in the above figure do not reflect any costs related to PREPA's legacy debt or its underfunded pension liability. The May 2019 PREPA Restructuring Support Agreement would impose a surcharge on electric rates of 2.6 cents/kWh

[38] This assumption takes into account $1.9 billion in forthcoming HUD funding for grid reconstruction work, an existing allocation of $850 million in FEMA 404 funding for natural gas plants that could be repurposed and the fact that PREPA has proposed to spend $8.4 billion in FEMA 428 funding on its transmission and distribution systems despite only receiving Energy Bureau approval to spend about $2 billion over the next 5 years.

in 2035,[39] which would push rates above 20 cents/kWh in all but the last of the scenarios show in Figure 7, without any provision for PREPA's pension liability.

Finally, we highlight that Figure 8 reflects average cost of the system; no specific ratemaking policy is assumed. The cost of residential and commercial rooftop solar and battery installations will decline over time, and it should be a goal of public policy to ensure that rates for all customers are just and reasonable. This would require decisions about how to allocate subsidies across income levels to ensure an equitable transition in which low-income households are able to participate in energy resiliency solutions.

Achieving the Queremos Sol Scenario

The Queremos Sol high penetration scenario (75% distributed renewable energy by 2035) is the most cost-effective strategy modeled thus far for PREPA to achieve RPS goals, mitigate risks due to grid failure, lower CO_2 emissions and attain reasonable and more stable rates. PREPA's current path will not achieve these goals or the DER scenarios proposed by 2035. PREPA has been ordered by the Energy Bureau to procure a large amount of renewable energy and storage over the next several years (3750 MW of solar by 2023), but the focus is not on rooftop solar systems.

If PREPA were to aim specifically for a higher penetration of distributed renewable energy, it could implement an on-bill financing program in which customers could install solar and battery systems and pay back their investment through their electric bills. PREPA could directly offer the systems to customers, using PREPA employees and a network of local contractors, as needed, to perform the installations. A well-designed program should make use of community partners to market the program to households. If it is a requirement of federal funding that PREPA retain ownership of the systems, PREPA could lease the systems to customers.

It is clear that federal funds present a unique opportunity to lower overall systems costs while implementing DER scenarios modeled. In light of the experience of Hurricane Maria, there is a clear case to be made that siting generation at points of consumption (rather than relying on long-distance transmission) and enabling households to become self-sufficient in energy production will save lives in future severe storms. Significant federal funding is available (around $12 billion)[40], although thus far PREPA has proposed to use those funds towards rebuilding a centralized generation system reliant on fossil fuels.[41] In contrast, $9-$10 billion in federal funding could be deployed towards implementing high DER scenarios that would result in real resiliency, e.g. through deployment of rooftop PV and storage to serve critical loads. This level of funding leaves $2-$3 billion of federal funds available to address upgrades that require urgent attention at the transmission and distribution level.

[39] The Restructuring Support Agreement provides for 3.76 cents/kWh in FY 2035, which we have converted to 2020 dollars for consistency with Figure 6.
[40] Including FEMA 404 and 428 funds, and HUD CDBG funds
[41] PREPA currently proposes to spend over $800 million in FEMA 404 funds for a new natural gas plant near San Juan and new peaker generation. PREPA has also proposed to spend $8.4 billion in FEMA 428 funds on upgrades to its transmission and distribution systems.

Other jurisdictions provide examples of policies that have successfully achieved higher levels of distributed renewable energy penetration than PREPA is currently seeking to achieve. For example, more than 21% of households in Australia have rooftop solar installations.[42] Initially, feed-in tariffs helped drive the market for rooftop solar, but they have now been phased out. Rebates are still available to cover roughly one-third of upfront costs.[43] High electric rates (above US $0.20/kWh) have helped make rooftop solar an economic choice for households. Hawaii has achieved even higher penetrations of rooftop solar, with one-third of homes on the island of Oahu having rooftop solar.[44] With the highest electric rates in the United States, rooftop solar makes economic sense in Hawaii and has also been driven by supportive policies to compensate homeowners for power exported to the grid.[45]

Additionally, achieving the Queremos Sol scenario also requires significant investment in energy efficiency, which PREPA has already been ordered to do by the Energy Bureau.[46] There are many examples in the United States of ratepayer funded energy efficiency programs to achieve the levels of energy savings described in the EFG study. Such programs offer financial incentives to customers to install more efficient lighting, refrigeration, air conditioning, and other products, as well as solar hot water heaters, to encourage the adoption of efficient technologies. Although such programs cost money and are funded through electric rates, they ultimately save money for all customers because they are cheaper than the cost of investing in new generation. An important first step would be to conduct an energy efficiency potential study to inform the design of cost-effective energy efficiency programs.

Areas for Future Work

The modeling conducted for this study reveals several opportunities for future work:

- The Telos study was conservative in its decisions about which existing power plants could be retired. A more detailed study of resource adequacy would show which additional units would be candidates for retirement or conversion to synchronous condensers.
- Both the Telos and EE Plus studies recommended additional studies and modeling tools to evaluate other options for grid stability at the 75% DER scenario.
- A residential appliance saturation study, and a similar study to determine baseline commercial energy consumption, should be undertaken to better understand current energy consumption. This would inform the design of effective energy efficiency programs to achieve the desired savings.[47]

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[42] Australian Department of Industry, Science, Energy and Resources, "Solar PV and Batteries," https://www.energy.gov.au/households/solar-pv-and-batteries, last accessed January 26, 2021.
[43] Jason Deign, "What the U.S. can learn from Australia's roaring rooftop solar market," Greentech Media, August 3, 2020.
[44] Hawaiian Electric, "2019 saw 21% jump in solar generation capacity," January 17, 2020.
[45] Hawaiian Electric, "Private Rooftop Solar," last accessed January 26, 2021.
[46] The Energy Bureau ordered PREPA to "Support all necessary steps to establish EE programs at 2%/year savings including quick-start programs." (Puerto Rico Energy Bureau, Final Resolution and Order, Case No. CEPR-AP-2018-0001, August 21, 2020, p. 283.)
[47] EFG report, p. 8.

- Additional avenues for future study are outlined in Section 10 of the Telos report.

In addition to technical modeling needs, more work must be done to identify workforce development and training needs and to identify possible sources of federal funding to support worker training. Additional investigation is also needed to develop a plan for recycling of PV and battery systems at the end of their useful lives.

Conclusions

In 2018, Queremos Sol put forth a vision of Puerto Rico's electrical system based on efficiency and decentralized, renewable energy. The modeling summarized in this report has shown that achieving 75% distributed renewable energy in 2035, with 100% of households equipped with solar and battery storage to address critical loads, is both technically and economically feasible. This scenario would result in a grid that is far less dependent on long-distance south-to-north transmission, that does not rely extensively on imported fossil fuels and that does not lock Puerto Rico into new natural gas infrastructure. Achieving this scenario will require a change of course in policy to truly prioritize rooftop solar and storage systems. Puerto Rico has a historic opportunity to use billions of dollars of federal grid reconstruction funding to redesign an electrical grid to promote real resiliency, an opportunity which is unlikely to come again.

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Ingrid M. Vila-Biaggi is co-founder and President of CAMBIO, a non-profit organization based in Puerto Rico that designs, promotes and implements sustainable policies and practices. She has held several government positions, including Chief of Staff for the Commonwealth of Puerto Rico where she oversaw policy development and implementation of over 100 agencies and corporations and served as liaison to the Puerto Rico White House Task Force. She collaborates and coordinates Queremos Sol, an alliance of environmental, labor, community groups and energy experts, aimed at transforming Puerto Rico's energy sector, establishing a 100% clean renewable path. She also works with the Caño Martín Peña communities as Urban Waters Ambassador. Vila-Biaggi is a former Open Society Leadership in Government Fellow and recently joined the Institute for Energy Economics and Financial Analysis' Board. Vila-Biaggi has a bachelor's degree in Civil and Environmental Engineering from Cornell University and a master's degree in Environmental Engineering from Stanford University.

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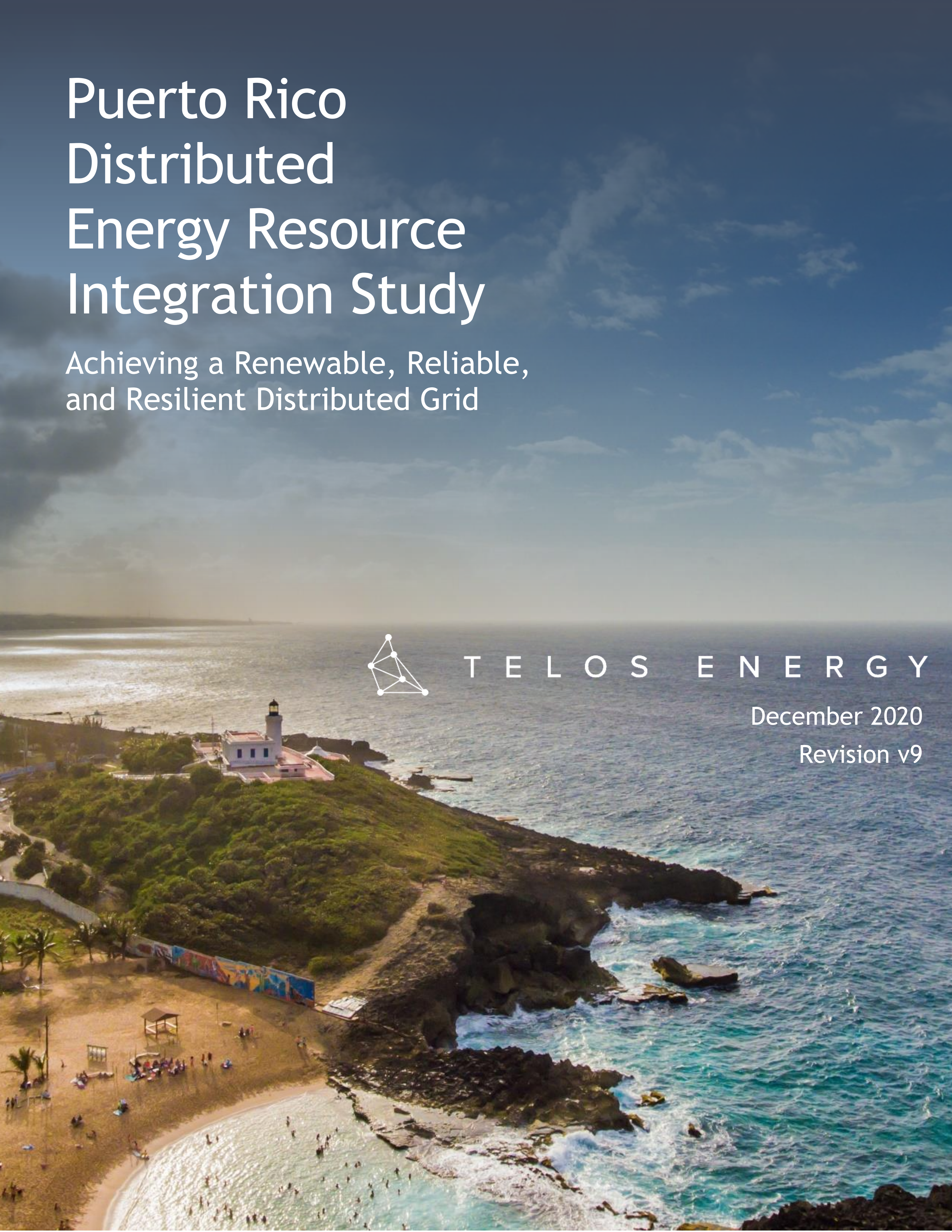
Puerto Rico Distributed Energy Resource Integration Study

Achieving a Renewable, Reliable, and Resilient Distributed Grid



TELOS ENERGY

December 2020

Revision v9

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Puerto Rico Distributed Energy Resource Integration Study

Achieving a Renewable, Reliable, and Resilient Distributed Grid

CAMBIO

ENERGY FUTURES GROUP

Institute for Energy Economics and Financial Analysis
IEEFA.org

ENERGIZING NEXT GEN SOLUTIONS

Filantropía Puerto Rico

TELOS ENERGY

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Revision History

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Rev06	10/30/2020	D. Stenclik	Initial draft submitted to CAMBIO for review
Rev07	11/30/2020	D. Stenclik	Final draft incorporated CAMBIO comments
Rev08	12/18/2020	D. Stenclik	Final draft submission
Rev09	2/23/2021	D. Stenclik	Minor adjustments
Rev10	3/2/2021	D. Stenclik	Minor adjustments
Rev11	3/4/2021	D. Stenclik	Minor adjustments

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List of Abbreviations

AC	Alternating Current
BCF	Billion Cubic Feet
BESS	Battery Energy Storage System
CC	Combined Cycle
DC	Direct Current
DER	Distributed Energy Resource
DPV	Distributed Photovoltaic
DR	Demand Response
EE	Energy Efficiency
EIA	US Energy Information Agency
EMT	Electromagnetic Transient
ES	Energy Storage
FFR	Fast Frequency Response
FO&M	Fixed Operations and Maintenance
GADS	NERC Generating Availability Data System
GIS	Geographic Information System Mapping
GT	Gas Turbine (aka Combustion Turbine)
GW	Gigawatt (1,000 megawatts)
IBR	Inverter Based Resource
IRP	Integrated Resource Plan
LNG	Liquified Natural Gas
MVA	Million Volt Amperes
MW	Megawatt (1,000 kilowatts)
NEPR	Negociado de Energía de Puerto Rico
NREL	National Renewable Energy Laboratory
NSRDB	NREL National Solar Radiation Database
OE	Oeste (West)
PREB	Puerto Rico Energy Bureau
PREPA	Puerto Rico Electric Power Authority
PSSE	Siemens Power System Simulator for Engineering tool
PV	Photovoltaic
RPS	Renewable Portfolio Standard
SAM	NREL System Advisor Model
ST	Steam Turbine
STG	Steam Turbine Generator
TC	Tap Changer
UFLS	Under-Frequency Load Shedding
VO&M	Variable Operations and Maintenance

Executive Summary

The aftermath of Hurricane Maria led PREPA to propose several new plans to rebuild the island's infrastructure and make investments to strengthen the island's power grid. In 2019, PREPA completed the Integrated Resource Plan, outlining potential new investments to meet current and future system needs. Many of these investments were large-scale, centralized fossil generation.

As an alternative to PREPA's plans, a multisectoral coalition comprised of community and labor groups, as well as environmental and energy experts presented Queremos Sol in 2018[1] as a holistic path to modernize Puerto Rico's energy sector to attain a more sustainable, resilient and equitable electric system. Queremos Sol's grid transformation is driven by: (1) efficiency, conservation and demand management; (2) distributed renewable generation with storage emphasizing roof top solar; and (3) accelerated phase-out of fossil-fuel generation. Queremos Sol seeks to achieve 25% energy efficiency and a minimum 50% renewable generation by 2035 to attain 100% renewable generation by 2050.

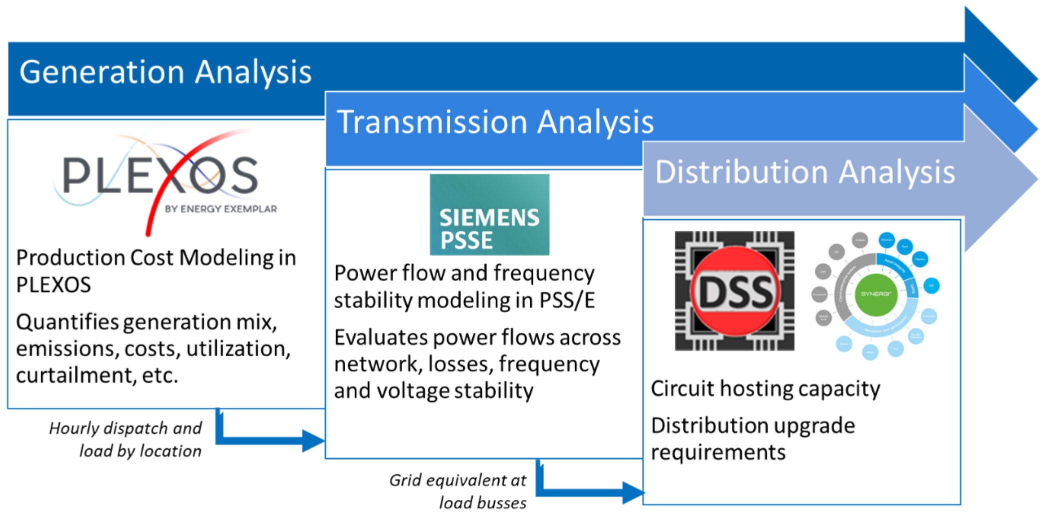
The objectives of this study are to provide a detailed economic and technical analysis evaluating a radically different energy mix than Puerto Rico has today as proposed by Queremos Sol. Specifically, it will utilize detailed grid planning for the following:

- Illustrate a future grid integrating with high levels of distributed energy resources, prioritizing rooftop solar and storage, following the Queremos Sol proposal,
- Evaluate a future grid designed to meet Puerto Rico's renewable, resiliency, reliability, and economic goals,
- Understand the operational, transmission, and distribution opportunities, and challenges associated with DER integration to evaluate possible mitigations to ensure stable and reliable growth of DER,
- Quantify the effects of DER integration, including changes to renewable generation, avoided fuel consumption, reduced CO_2 emissions, potential curtailment, unit cycling, and grid stability, and
- Present a possible schedule for fossil fuel generation phase out following DER integration increase.

To evaluate the changes to power system operations and grid stability with increasing DER, this analysis leveraged detailed power system simulation and modeling software. Four scenarios were selected to represent potential future power systems with increased DER. Grid configurations were evaluated with increasing installations of DER, corresponding to residential PV, commercial PV, and behind-the-meter battery energy storage, as well as corresponding fossil generator retirements.

The study levered detailed modeling and power system simulation to quantify the operational and grid stability challenges associated with high DER integration. A diagram of the modeling process is provided in the figure below.

[1] For additional details please refer to the Queremos Sol proposal (www.queremossolpr.com)



Overview of Software Tools and Methods

This study evaluated three scenarios for Puerto Rico's future electric generation mix, reaching 25%, 50%, and 75% of annual energy from renewable sources and a 25% reduction in load due to energy efficiency. These scenarios provide a pathway to meet and exceed the Queremos Sol 2035 RPS objectives and put the system on a trajectory to achieve the 100% clean energy by 2050.

The study scenarios met these renewable goals using DER exclusively. This translates to between 50% and 100% of single-family homes in Puerto Rico integrating rooftop solar. Residential systems were assumed based on installations in Puerto Rico, ranging between 1.8 kW to 4.2 kW of PV and 7.2 to 21.6 kWh of behind-the-meter battery storage. The remaining PV necessary to reach the RPS targets was assumed to be distributed across commercial and industrial customers, solar carports, and repurposed landfills or brownfields.

Assuming gross energy sales after energy efficiency of 11,700 GWh, and an annual rooftop solar capacity factors of approximately 19%$_{ac}$, these renewable targets equate to approximately 1500 MW (25% DER), 3200 MW (50% DER), and 5000 MW (75% DER) of installed distributed PV. The scenarios also included a large buildout of behind-the-meter battery energy storage, with all residential PV systems including battery storage, assuming each residential PV system was paired with, on average, 4.5 hours of storage. For example, a 2.7 kW rooftop PV system paired with a 12.6 kWh behind-the-meter battery. An overview of the renewable goals and DER capacities by scenarios is provided in the following table.

Scenario Overview

		25% DPV	50% DPV	75% DPV
Renewable Share	% of Total Sales	25%	50%	75%
Resilient Homes	% of Resilient Homes	50%	75%	100%
Distributed PV Capacity (MW)	Residential	1,350	2,025	2,700
	Commercial	143	1,212	2,282
	Total	1,493	3,237	4,982
Distributed BESS Capacity	Power Rating (MW)	1,178	1,853	2,528
	Energy Rating (MWh)	5,301	8,339	11,376
	Duration (hrs)	4.5	4.5	4.5

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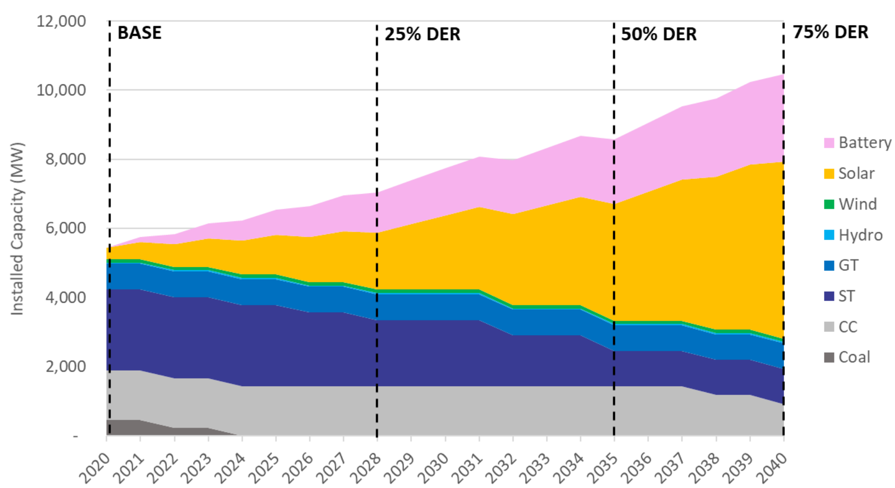
The study also outlined and evaluated a potential phase-out of fossil generation and included fossil retirements that could be achieved based on the amount of DER integration. To determine the sequence of fossil-fired unit retirement for each scenario, a weighted a combination of seven factors was developed, which included: age, emissions, flexibility, dependence on long-distance transmission (south to north), fixed operations and maintenance costs, generation costs (fuel costs, variable costs, etc.), and reliability (forced outage rates). The result included 2,300 MW of fossil generator retirements and included the AES coal plant, Palo Seco Power Plant, and the Aguirre Power Plant. By replacing legacy coal and oil-fired steam generating units with state of the art solar and battery energy storage systems, Puerto Rico's grid would become cleaner, more flexible, and more reliable.

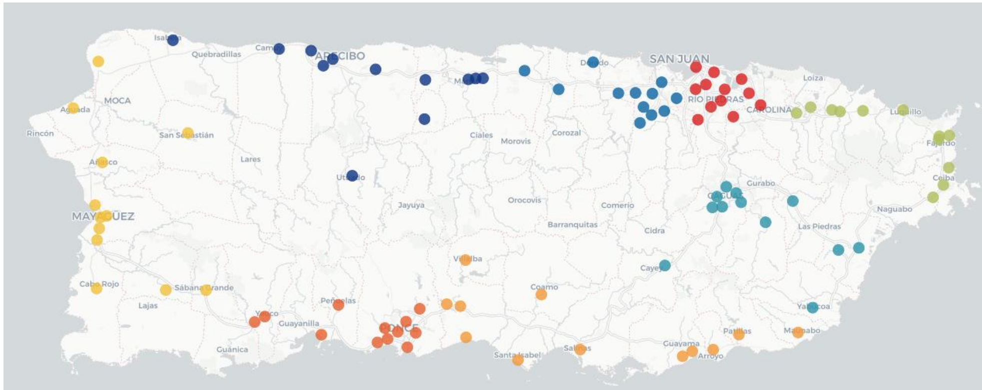
The combination of solar PV, battery additions, and fossil generator retirements creates a resource mix that is fundamentally different than the one Puerto Rico has today and would take time to develop. For the purposes of long-term planning, the transition is spread across a 20-year horizon as shown in the figure below. On an installed capacity basis, solar and storage (inverter based resources) become the largest form of capacity by the 50% DER scenario and total installed capacity in Puerto Rico increases to over 10 GW by the 75% DER scenario, nearly double today's capacity despite increased energy efficiency.



Installed Capacity by Resource Type

For this analysis, 96 solar sites were selected across Puerto Rico to represent the distributed rooftop PV. Sites were concentrated in developed areas where residential and commercial PV systems would be most prevalent. Twelve sites were selected in each of the eight regions of the island, where the installed capacity was weighted based on the density of urban development and existing transmission and distribution infrastructure. In general, capacity factors are highest along the coast and at lower elevations away from the mountainous interior.

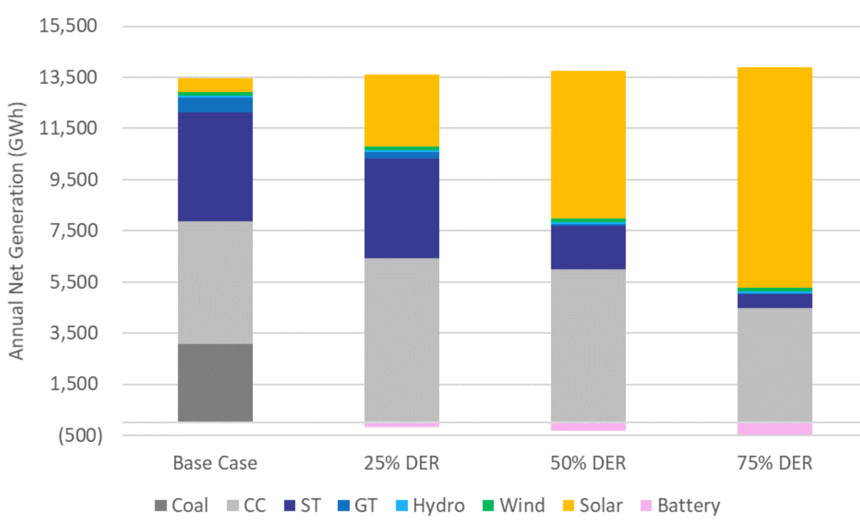
For each of the 96 sites identified, a full year of chronological, 5-minute resolution weather data was downloaded from the NREL Puerto Rico Simulated High Resolution Dataset and converted into power production profiles. This generated over 10 million data points of chronological solar data that were modeled for the study to ensure adequate geographic diversity and granular chronology of variability. The data was then aggregated for each region by averaging the twelve sites into a single composite regional profile for use in the production cost modeling.



Map of Simulated Solar Locations Across Puerto Rico
(colored by region)

Results of the analysis show that grid operations change markedly as the system moves towards a higher penetration of DER. Figure 15 highlights how annual generation by unit type changes over the four scenarios studied. As solar generation increases, it displaces fossil fuels on the grid. The types and amount of fossil fuel displacement depends on the costs, flexibility, and physical characteristics of each generating unit. The retirement of AES in all but the Base Case stands out with the coal unit type denoted by a dark gray. The immediate result of a system without AES and a 25% integration of DER is an increased role for existing combined cycle (CC) plants. The 25% DER case shows much of the generation once provided by AES is instead produced by existing combined cycle plants, which operate on either LNG or oil fuels.

As the penetration of DER increases in the 50% and 75% DER cases, solar takes on a much larger role and begins to displace steam turbine (ST) units and later CC units. While simple-cycle gas turbines (GT), also referred to as "peakers," generate a relatively low amount of generation in the base case, their role in total generation is reduced further in the 50% and 75% scenarios as battery energy storage effectively reduces peak loads. The figures below show the annual generation mix (top) and representative daily generation profile (bottom) across each of the scenarios evaluated.



Annual Net Generation by Unit Type

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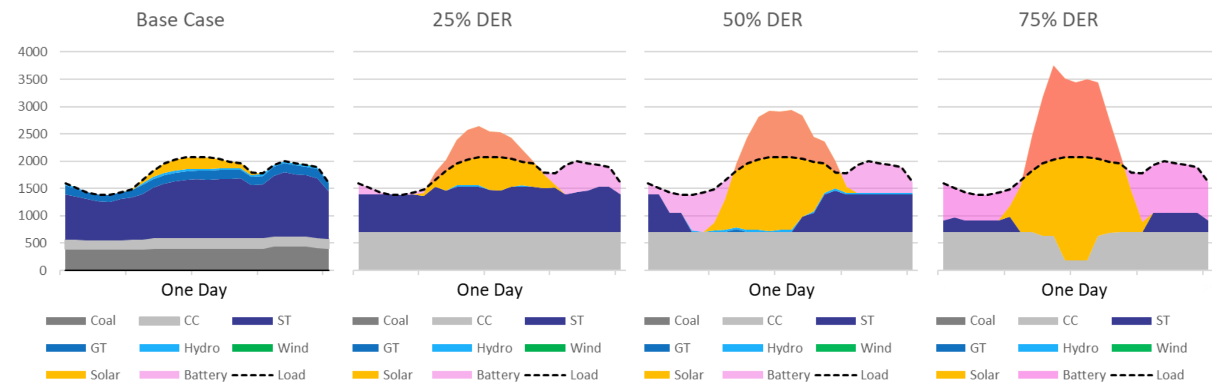
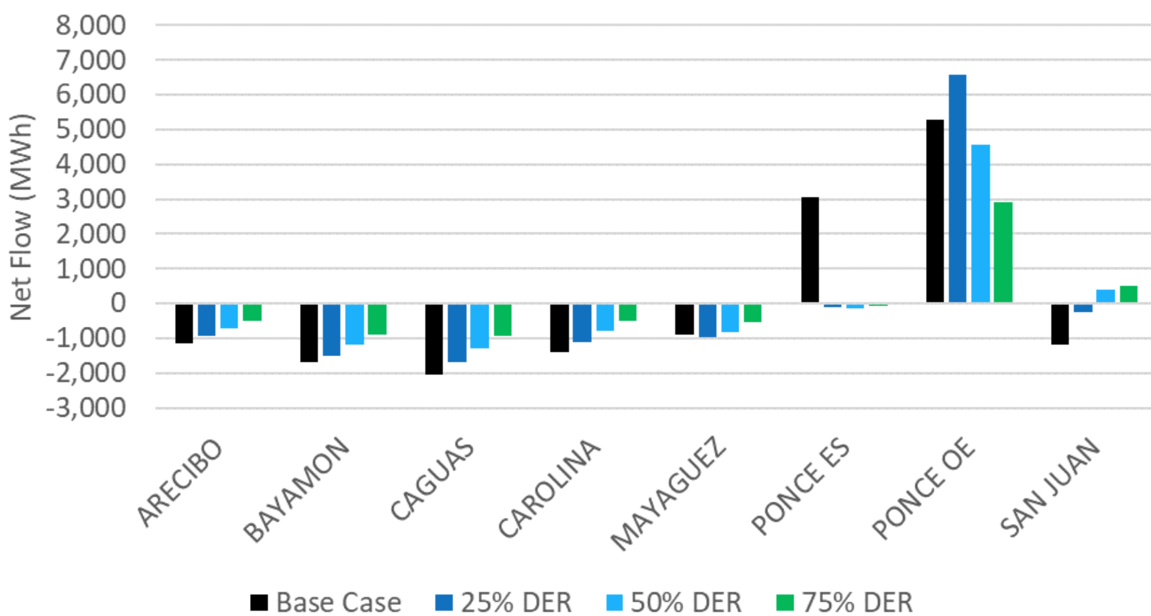


Dispatch Diagrams for a "Normal" Day

The study also quantified changes of power flows across the transmission network, provided in the figure below. Positive numbers represent net exports and negative numbers represent net imports. In the Base Case, both Ponce ES and Ponce OE are the only net exporters among the eight regions. The overarching trend from the Base Case to the 75% DER case is that net flows decrease as each individual region becomes more self-sufficient with the increase in DER as generation is sited directly at the point of consumption. The reduced flows across the network has several benefits, including reduced transmission losses and increased reliability because the system becomes less susceptible of transmission outages, failures, and storm related damage.

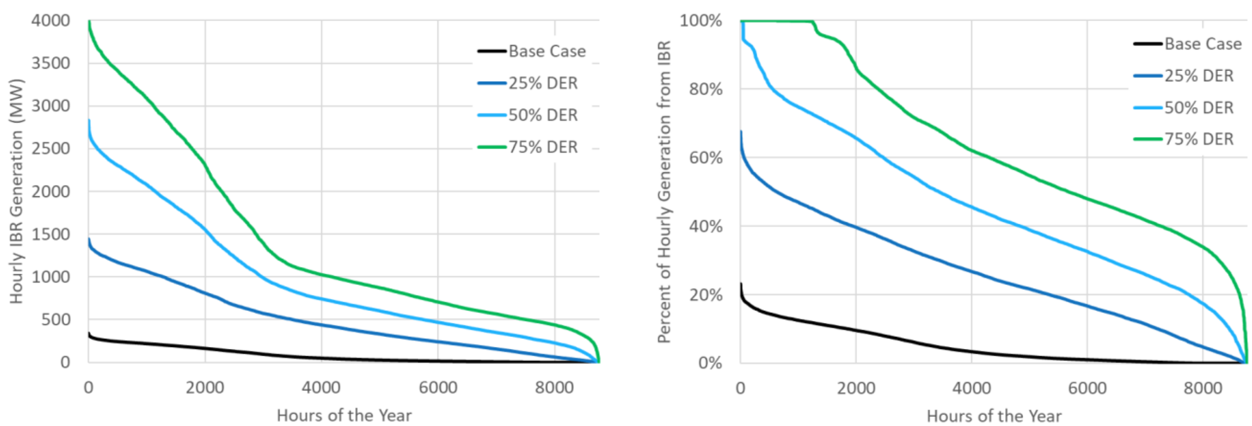


Annual Net Flows by Regions

The study also evaluated the instantaneous operation of these resources across the entire year. This is important because both solar and batteries (as well as wind) resources are inverter-based resources (IBR). IBRs connect to the grid through a power electronic interface, called an inverter, whose software-defined controls determine the behavior, performance, and stability of these resources on the grid. As

IBRs take on a larger role in the grid, there will be operational and grid stability challenges given inherent limitations of current inverter technology. It is important to note that because solar and wind resources are variable, there are hours of the course of a year when IBRs will dominate the behavior of the grid by reaching very high levels of penetration (as a percentage of the grid's total resource mix) even if their annual generation levels are relatively modest.

In the scenarios evaluated, there are times when inverter-based generation exceed 50% of instantaneous load even in the 25% DER scenario, and periods reaching 100% instantaneous penetration in the 50% and 75% DER scenarios. These periods require close attention and detailed grid stability evaluations the electric power industry has little to no experience with inverter-dominant island grids at the scale of Puerto Rico's grid.



Duration Curves of IBR Generation (left) and Percent of Total Generation (right)

All electric power grids must be analyzed to ensure stable operation under a large variety of operating conditions, environments, and grid disturbance events. This is true regardless of the level of renewables on the grid. However, grids with very high levels of renewables face more acute technical challenges because of the high-levels of IBR like PV and battery systems and the displacement of conventional power plants with synchronous machine technology. However, these new resources also offer new benefits for supporting the grid in ways that were not previously available with conventional power plant technology.

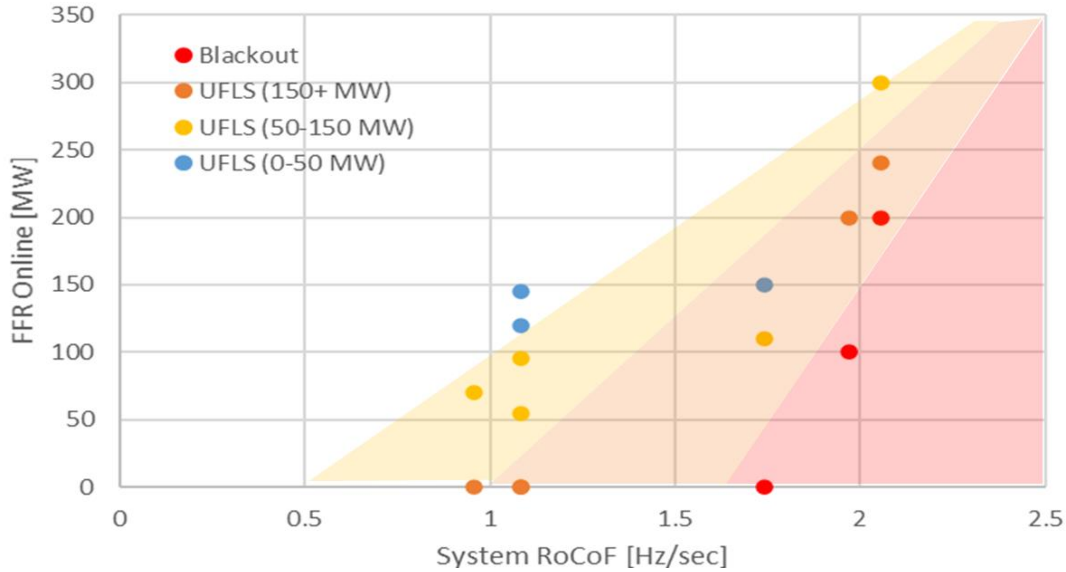
These benefits are primarily due to the flexibility and speed of the inverters that form the interface between the resource (solar or battery) and the grid. The flexibility is because of a programmable response of inverters to different grid conditions and grid events. The speed refers to the faster rate at which IBRs are capable of responding to changing grid conditions. While a fast or faster response is not always desirable, it can be useful in certain circumstances. These advantages, coupled with an energy reservoir as in the case of battery storage, makes for a powerful combination (as shown through simulated response of the grid to challenging events) that can help support a future grid with a dramatically different generation mix than the one that exists today.

To assess the stability of the grid under the proposed high-renewable scenarios, the frequency stability, fault recovery, and inverter control stability were evaluated by simulating the response of the grid to disruptive events or grid disturbances.

- **Frequency Stability:** Grid frequency is held close to 60Hz by maintaining a balance between generation and load. If generation exceeds load (for instance, due to a sudden loss of load), then grid frequency rises and generation must be reduced to bring frequency back to nominal. If generation drops below load (for instance, due to a sudden loss of generation), then grid frequency decreases and additional power must be injected to the grid, or load must be reduced or shed, in order to restore grid frequency.
- **Fault Recovery:** The ability of the grid to recover from a fault event, or a short-circuit on the grid is termed fault recovery. Grid faults may be causes by obstructions like trees falling on transmission lines, lightning strikes of lines or towers, the collapse of transmission towers, etc. When such a fault occurs, the grid is designed to quickly remove the faulted transmission line from service, thereby "clearing" the fault from the grid. The desired intent is that the grid continues to operate without the line in-service until a crew can be dispatched to repair the line.
- **Inverter control stability**: refers generally to the behavior of an inverter to respond in a stable manner to grid events like the loss-of-generation events and fault events described. Examples of unstable behavior includes oscillatory behavior to a failure to ride-through and recover from the disturbance without causing voltages or currents that are damaging to the inverter or other equipment. While oscillatory behavior may be acceptable for brief periods of time (well-damped behavior), sustained or growing oscillations are not acceptable.

The grid stability simulations capture the dynamic response of the grid over the course of 10 to 20 seconds following a grid event like a loss of generation or a fault event. Because it is impractical to simulate the dynamic response of the grid over the course of an entire year, as was evaluated in the production cost analysis, a selection of "snapshots" in time from each of the scenarios was selected for simulation of dynamic grid stability. The selection of these "snapshots" is very important as they must be chosen to be representative of a range of grid operations and not "cherry-picked" as worst-case or best-case operations, which would skew the conclusions drawn from the results.

Results of these simulations show that as IBRs increase on the grid and conventional generation is displaced, the grid spends more time operating in periods of low system inertia. If no mitigations were applied, it would be expected that blackouts would occur more frequently for loss of generation events. However, if FFR (note this is only one of many types of mitigation) is applied, it can not only enable the grid to survive loss-of-generation events, but also reduce or eliminate the need for load shedding. It is important to note that correctly applying FFR is not trivial. If the FFR is tuned to be too slow, it will not be effective and the grid may fail to survive the event. However, if the FFR is tuned to be too fast, it may over-react and/or result in oscillatory behavior and participate in adverse interactions with other grid equipment, destabilizing the grid and ultimately leading to a failure to survive the event. However, it must be noted that for extremely low levels of inertia, FFR loses its efficacy.



Summary and Trends Identified from Loss-of-Generation Events

In addition, the grid stability simulations show the evolution of DER controls and the resulting improvement in performance of the grid in response to transmission fault events. Beginning with basic implementation of "smart-inverter" functions and ending with tuned smart-inverter functions and reasonably expanded inverter protection settings, the performance of the grid can be greatly improved. The results are simplified and summarized in the following figures, which are color-coded as follows: green cells for in cases where performance is considered good, similar to that shown in the current scenario, orange is used for marginal performance where the grid survives but with some loss of DER and/or loss of load. Red is used for cases in which the system does not survive the fault event. Brown is used for cases in which there is evidence that the simulation tool is not capable of accurately simulating the event.

Line | Scenario	Current	25%	50%	75%
Costa Sur-Manati 230kV				
Costa Sur-Mayaguez 230kV				
Costa Sur-Dbocas Fase 230kV				
Aguirre-Agubuena 230kV				
Cayey-Caguas 115kV				
Guanica-San German 115kV				

Performance Summary for Grid Faults with Basic DER Functionality

Line | Scenario	Current	25%	50%	75%
Costa Sur-Manati 230kV				
Costa Sur-Mayaguez 230kV				
Costa Sur-Dbocas Fase 230kV				
Aguirre-Agubuena 230kV				
Cayey-Caguas 115kV				
Guanica-San German 115kV				

Performance Summary for Grid Faults with FFR and Improved Volt-Var DER Functionality

Line | Scenario	Current	25%	50%	75%
Costa Sur-Manati 230kV				
Costa Sur-Mayaguez 230kV				
Costa Sur-Dbocas Fase 230kV				
Aguirre-Agubuena 230kV				
Cayey-Caguas 115kV				
Guanica-San German 115kV				

Performance Summary for Grid Faults with FFR and Improved Volt-Var and Expanded Over-Voltage Protection from DER

The results of this study are significant and clearly illustrate that Puerto Rico can radically shift its power system to one that is based on local, renewable, and resilient distributed energy resources. This can be done in a way that improves system reliability, grid stability, and resiliency for Puerto Rico's ratepayers. This transition will yield environmental benefits with reduced CO_2 emissions and other environmental pollutants and will considerably decrease fossil fuel consumption in Puerto Rico. This will make the power system and the economy less susceptible to the fuel price volatility of oil markets and more energy independent. In addition, the study results produced the following key findings:

- DER can be used as a tool to accelerate the retirement of Puerto Rico's aging fossil fleet replacing that capacity with more flexible, clean, and resilient technology. The AES coal plant, for example, could be retired by 2024 with investment in DERs and energy efficiency.
- Increased flexibility will be required of the fossil fleet, especially for the CC units, which will be expected to cycle on and offline more often and run for fewer hours per year. This may change the maintenance requirements, cycling costs, and reliability of these generators in the future.
- Renewable curtailment is quite low across all scenarios and is highest (on a relative basis) in the Base Case before any storage is added. Total renewable energy perspective, curtailment is limited to 1% even in the highest DER scenarios.
- Oil and gas fuels both experience more than a 50% decline in consumption by the 75% DER scenario. As a result, Puerto Rico would be less susceptible to fuel price volatility and would become more energy independent with increased DER adoption. This reduction in fuel consumption also translates to a more than 70% reduction (over 6 million tons) in carbon dioxide emissions by the 75% DER case.

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- The production cost savings (not accounting for capital cost of new resources) from introducing more DER onto the grid while also retiring fossil fuel-based generation are considerable, with savings range anywhere from roughly $144 million (25% DER) to $703 million per year (75% DER). This equates to an avoided energy cost of $64 to $86/MWh of additional solar energy.
- Another benefit of DER integration is that the resources are sited directly at the loads, reducing the total amount of energy that flows across the transmission network. This yields reliability, resiliency, and avoided transmission loss benefits. Across the scenarios analyzed, DER reduced net flows across the network as each individual region becomes more self-sufficient with the increase in DERs located within that respective region.
- In the 50% DER and 75% DER case there are hours with 100% of generation coming from IBR, even after using storage to shift much of the surplus generation. With current inverter technologies and the absence of synchronous condensers, this level of operation would not be reliable, but changes to operations can be made to ensure reliability if those mitigations are not available.

DER inverter controls for grid-response is critical to achieving stable grid operation up through the 50% scenario. The use of DER inverter functions like frequency-watt response (FFR) and volt-var response that are tuned for fast-response are effective in stabilizing the grid for significant disturbances. About 300MW of FFR is needed to enable the grid to survive generation-loss events through the 50% scenario.

1 Introduction

1.1 Study Objectives

Puerto Rico's power system is at a pivotal transition point. Hurricane Maria, which hit Puerto Rico in September of 2017, created catastrophic damage across the island including much of the power grid. Many regions and residents were left without power for months. In addition, the aging infrastructure of the Puerto Rico power grid and financial stress of the island's utility and grid operator Puerto Rico Electric Power Authority (PREPA), have severely eroded system reliability.

These events have led PREPA to propose several new plans to rebuild the island's infrastructure and make investments to strengthen the island's power grid. In 2019, PREPA completed the Integrated Resource Plan, outlining potential new investments to meet current and future system needs. Many of these investments were large-scale, centralized fossil generation.

As an alternative to PREPA's plans, a multisectoral coalition conformed of community and labor groups, as well as environmental and energy experts presented Queremos Sol in 2018[2] as a holistic path to modernize Puerto Rico's energy sector to attain a more sustainable, resilient and equitable electric system. Queremos Sol's grid transformation is driven by: (1) efficiency, conservation and demand management; (2) distributed renewable generation with storage emphasizing roof top solar; and (3) accelerated phase-out of fossil-fuel generation. Queremos Sol seeks to achieve 25% energy efficiency and a minimum 50% renewable generation by 2035 to attain 100% renewable generation by 2050.

Concurrent to these events two significant shifts have taken place in Puerto Rico's energy sector. First, there has been a prioritization of residents towards resiliency, with many residents investing in behind-the-meter backup generation. Second, the economics of distributed generation - specifically solar photovoltaic (PV) and battery energy storage systems (BESS) - have become increasingly favorable. As a result, distributed energy resource (DER) adoption across Puerto Rico has increased significantly and growth is expected to continue as long as the regulatory structure and power grid allows for it.

The objectives of this study are to provide a detailed economic and technical analysis evaluating a radically different energy mix than Puerto Rico has today as proposed by Queremos Sol. Specifically, it will utilize detailed grid planning for the following:

- Illustrate a future grid integrating with high levels of distributed energy resources, prioritizing rooftop solar and storage, following the Queremos Sol proposal,
- Evaluate a future grid designed to meet Puerto Rico's renewable, resiliency, reliability, and economic goals,
- Understand the operational, transmission, and distribution opportunities and challenges associated with DER integration and possible mitigations to ensure reliable growth of DER,
- Quantify the effects of DER integration, including changes to renewable generation, avoided fuel consumption, reduced CO_2 emissions, potential curtailment, unit cycling, and grid stability.
- Present a possible schedule for fossil fuel generation phase out following DER integration increase.

[2] For additional details please refer to the Queremos Sol proposal (www.queremossolpr.com)

The results of this study will quantify the effects of high DER integration, with solar energy becoming the primary source of electricity across Puerto Rico and integration of battery storage to meet reliability and resiliency needs.

The results will also provide an alternative future scenario for Puerto Rico that puts the island on a path towards 100% renewable energy. While a 100% renewable energy system is the Queremos Sol end goal, this study is meant to provide a roadmap to higher renewable energy and thus focus attention on intermediate renewable goals of 25%, 50% and 75% of annual sales. This is intended to convince key stakeholders – including PREPA engineers and executive management, the Puerto Rico Energy Bureau (PREB), US Department of Energy (DOE), among others - that a high solar future can be operated with a high degree of reliability and grid stability. At the same time the study will contribute to Queremos Sol's continued effort for public engagement and capacity building regarding a more sustainable and equitable energy sector transformation.

1.2 Data Collection

Information and data used for the study were provided by PREPA during the month of April 2020. (Please refer to Section 3 for more detailed information on data input). Furthermore, as part of the development of the model two virtual sessions were held with PREPA personnel to clarify information and calibrate progress.

Although data used was provided by PREPA the model has been independently developed by Telos on behalf of CAMBIO PR and in no way represents any proposal, projection or representation of the Puerto Rico Electric Power Authority.

1.3 Queremos Sol Feedback

During the course of the study's model and scenario development, two meetings were conducted with the Queremos Sol group. These meetings covered the objectives, methodologies, and preliminary results of the study in order to solicit feedback from the group on the methodology and assumptions used in the study so that the scenarios reflected the goals and objectives of the Queremos Sol group. This feedback was instrumental in determining the amount of PV and battery storage assumed in each scenario, the timing and prioritization of assumed fossil retirements, assumptions related to new unit installations and energy efficiency targets.

1.4 Methodology & Process

To evaluate the changes to power system operations and grid stability with increasing DER, this analysis leveraged detailed power system simulation and modeling software. Four scenarios were selected, identified in Section 2, to represent potential future power systems with increased DER. Grid configurations were evaluated with increasing installations of DER, corresponding to residential PV, commercial PV, and behind-the-meter battery energy storage, as well as corresponding fossil generator retirements. All other assumptions were held constant across the scenarios to isolate the effects of the additional DER.

The software tools used in this analysis are available from third-party software vendors, heavily used throughout the industry, and are the same ones leveraged by PREPA and other global utilities. These grid planning tools allow for an evaluation and simulation of a future power system using the same methods and processes used to operate and control today's grid to isolate the effects of integrating DER, new technology, and operational changes.

When it comes to power system modeling, no one tool can provide a comprehensive analysis across the generation, transmission, and distribution segments of utility planning. In addition, no one tool can properly evaluate all the timescales of planning, which range from sub-seconds to an entire year, or years, of operation. To overcome this limitation, this study leveraged multiple power system planning tools with tight coupling between the different stages. This allows for each tool to properly evaluate its domain, while linking inputs, assumptions, and outputs between the tools to ensure the study overcomes seams in the analysis typically found between the generation, transmission, and distribution analyses.

- **Generation Analysis**: utilized Energy Exemplar's PLEXOS production cost model to quantify hour-to-hour, and sub-hourly operation of the grid to match load and generation in a least cost manner. The outputs of this model provide generator dispatch levels and load allocation by location for subsequent transmission modeling.
- **Transmission Stability Analysis**: utilized Siemens' PSS/E power flow modeling software to evaluate dynamic stability on the transmission network (from 38kV to 230kV voltage levels), including frequency and voltage stability. The transmission model was also used to calculate the grid representation (Thevenin equivalent) at each load bus for subsequent distribution system modeling.
- **Distribution Analysis**: utilized EPRI's OpenDSS distribution tool (and validated output against DNVGL's Synergi model) to identify circuit hosting capacity and necessary distribution upgrades due to DER integration.

A diagram illustrating the linkages between the software tool can be found in Figure 1. While this diagram illustrates a unidirectional flow of information, there was also information passed in the reverse direction. For example, after the transmission analysis evaluated dynamic stability, it identified a potential mitigation to frequency instability (due to low synchronous inertia) and thus developed a new constraint that could be input into the generation analysis to ensure grid stability in commitment and dispatch decisions.

Note that the analysis presented in this report, and conducted by Telos Energy, is limited to the generation and transmission analysis. This work was coordinated with the distribution analysis, the results of which can be found in the report authored by EE+.

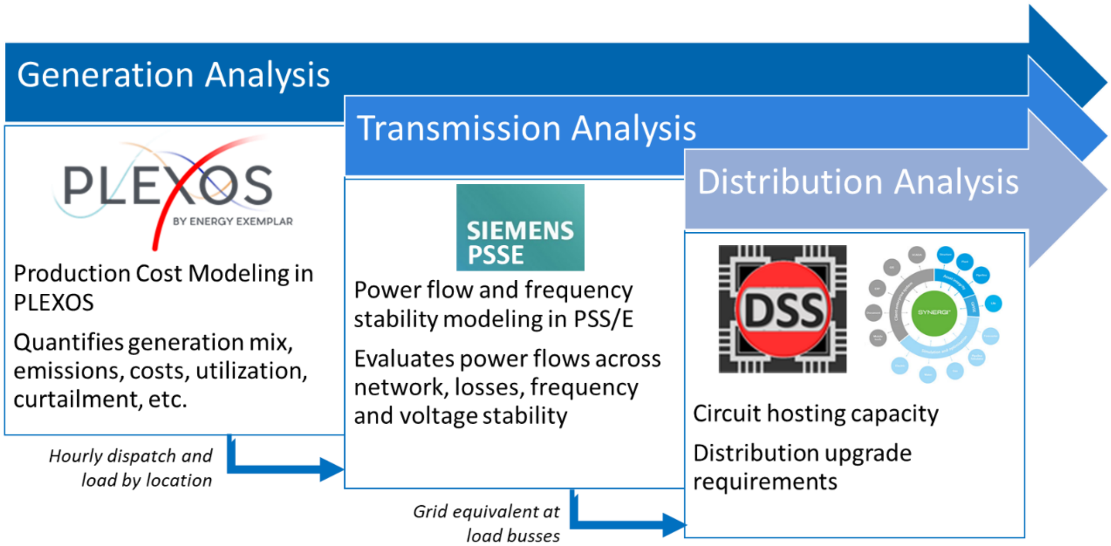

Figure 1: Overview of Software Tools and Methods

1.5 Study Limitations

The forward projections provided in this report are based on fundamentals analysis. While the authors took great care to ensure accurate and robust modeling, any forecast has uncertainty. As such, there are several limitations that should be identified, including:

- The model's representation of the grid's supply and demand is exogenously determined and is an input into the model. The starting point demand was assumed based on PREPA's 2020 forecasted energy load, reduced by the Queremos Sol 25% energy efficiency goal. The supply was based on PREPA's current installed generating fleet, with increasing additions of DER to evaluate the effects of increased solar adoption. The modeling did not evaluate an optimal least-cost capacity expansion and retirement plan, but rather evaluated grid operations and reliability across specific scenarios with costs and benefits calculated as a result of the study.
- DER was integrated with some level of coordination and control. This would allow the system operator to take into account expected generation from DER resources to commit and dispatch the system and schedule battery energy storage, at least in part, based on system needs. This study was a system-level analysis and did not evaluate the use of behind-the-meter solar and battery energy storage optimized for individual use.
- Distributed battery storage in this analysis is able to provide grid spinning reserve requirements through an aggregator that coordinates the output of many DER assets to provide controllable grid services. If this is not technically achievable in the short-term due to technology limitations of broad communications and coordination challenges, there may be a need for increased spinning reserves, which were not evaluated for this study.
- Because the residential solar PV was integrated as hybrid systems with coupled battery energy storage, this study also did not include an increase in reserves, above current requirements, due to either the variability or uncertainty of solar resources. The study used the reasonable assumption that the solar and battery resources could "self-regulate" and manage net-to-grid variability via ramp rate limits or other inverter controls.

- The grid stability analysis used fundamental-frequency positive-sequence simulation tools that represent a balanced system. Unbalance and asymmetric faults were not analyzed for dynamic stability.
- Each inverter is different, and the specific control loops used can make a difference on system stability. Without knowing the specific inverters that will be deployed in the future, this study made reasonable assumptions on their likely grid-interactive behavior. The dynamic models of the DER were represented with generic models, which are widely used as a best practice, but also do not capture all of the nuances of response present in real equipment. This limitation becomes more pronounced as the power rating of DER represented on the grid rises with respect to the online MVA rating of synchronous machines, particularly in the 75% penetration scenario.
- The dynamic stability model included representation of “grid-following” distributed inverter technology, which is widely in use as of this publication. This analysis does not contain representation of “grid-forming” inverter technology, a promising but not yet commercially available technology, but which may provide benefits to operating island power systems with few to no synchronous machines online.

2 Study Scenarios

2.1 Evaluating a Future Puerto Rico Energy Mix

Currently Puerto Rico generates less than 3% of its annual electricity from renewable sources, about half of which is from variable renewables like wind and solar. In October 2018, Queremos Sol – multisector clean energy and solar power advocacy group - released a report titled, “Queremos Sol: Sostenible, Local, Limpio.”[3] In the report, Queremos Sol set an ambitious goal to achieve a Renewable Portfolio Standard (RPS) of 50% by 2035 and 100% by 2050, and an Energy Efficiency and Conservation Policy Objective of 25% by 2035. In addition, it advocated for a clear public policy for the following:

- Efficiency, conservation, and demand management.
- Renewable distributed generation with storage, prioritizing rooftop solar.
- Accelerated phase-out of fossil fuels.

Underpinning all of these goals is the importance of reliability and resilience. When Hurricane Maria hit the island in 2017 it took several months for complete restoration of power. The blackout represents the largest grid reliability event in US history, with 3.4 billion lost customer hours.[4] Since that time, there have been multiple recent island wide blackout events due to earthquakes, storms, and generator failures. This has made reliability and resilience a new priority in Puerto Rico, with most electricity users investing in backup generation. In addition, many of the new rooftop PV systems installed across the island include battery storage for reliability purposes.

In addition to the renewable policy objectives of Queremos Sol and the reliability needs of the system, there is also clear economic justification for distributed energy resources. According to the EIA, residential and commercial electricity rates in Puerto Rico in 2019 were above 23 cents/kWh, double the US average.[5] This provides strong economic incentives for the adoption of rooftop PV and other distributed energy resources.

2.2 Solar and Storage Additions

Based on the drivers identified in the previous section, this study evaluated three scenarios for Puerto Rico’s future electric generation mix, reaching 25%, 50%, and 75% of annual energy from renewable sources and a 25% reduction in load due to energy efficiency. These scenarios provide a pathway to meet and exceed the Queremos Sol 2035 RPS objectives and put the system on a trajectory to achieve the 100% clean energy by 2050. The study also includes a fourth reference case that represents the system as it is today, with estimate of current levels of distributed rooftop PV and utility-scale solar, which was also included in the other scenarios. These four scenarios are referred to as the Base Case, 25% DER, 50% DER, and 75% throughout this report.

The study scenarios met these renewable goals using DER exclusively. This translates to between 50% and 100% of single-family homes in Puerto Rico integrating rooftop solar. Residential systems were assumed based on installations in Puerto Rico, ranging between 1.8 kW to 4.2 kW of PV and 7.2 to 21.6

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[3] Queremos Sol, https://www.queremossolpr.com/
[4] Rhodium Group, “The World’s Second Largest Blackout,” https://rhg.com/research/puerto-rico-hurricane-maria-worlds-second-largest-blackout/, April 2018.
[5] U.S. Energy Information Agency, “Puerto Rico Territory Energy Profile,” Last Update: March 2020.

kWh of behind-the-meter battery storage. The remaining PV necessary to reach the RPS targets was assumed to be distributed across commercial and industrial customers, solar carports, and repurposed landfills or brownfields.

Assuming gross energy sales after energy efficiency of 11,700 GWh, and an annual rooftop solar capacity factors of approximately 19%$_{ac}$,[6] these renewable targets equate to approximately 1500 MW (25% DER), 3200 MW (50% DER), and 5000 MW (75% DER) of installed distributed PV. The scenarios also included a large buildout of behind-the-meter battery energy storage, with all residential PV systems including battery storage, assuming each residential PV system was paired with, on average, 4.5 hours of storage. For example, a 2.7 kW rooftop PV system paired with a 12.6 kWh behind-the-meter battery. An overview of the renewable goals and DER capacities by scenarios is provided in Table 1 and Figure 2. Detailed assumptions on the calculations used to develop these values is provided in the Appendix, Table 17.

Table 1: Scenario Overview

		25% DPV	50% DPV	75% DPV
Renewable Share	% of Total Sales	25%	50%	75%
Resilient Homes	% of Resilient Homes	50%	75%	100%
Distributed PV Capacity (MW)*	Residential	1,350	2,025	2,700
	Commercial	143	1,212	2,282
	Total	1,493	3,237	4,982
Distributed BESS Capacity	Power Rating (MW)	1,178	1,853	2,528
	Energy Rating (MWh)	5,301	8,339	11,376
	Duration (hrs)	4.5	4.5	4.5

*Includes existing distributed PV

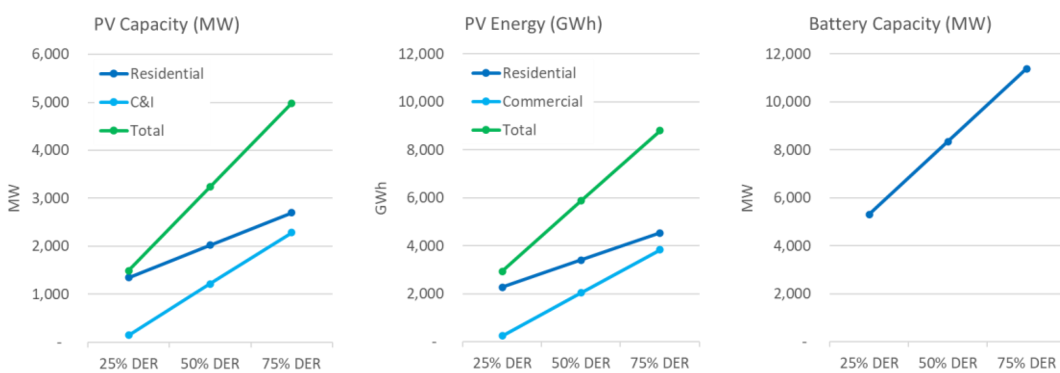

Figure 2: PV Capacity, PV Energy, and Battery Capacity by Scenario

[6] Annual capacity factors based on the National Renewable Energy Laboratory's National Solar Radiation Database (NREL NSRDB) and Puerto Rico specific locations. See Section 4.1 for more information.

2.3 Generator Retirements

The integration of solar PV and battery energy storage provides a path to initiate the retirement of Puerto Rico's fossil generation fleet. The fossil fleet is aging, with an average age of 41 years and some units exceeding 60 years of operations. This leads to high likelihood of generator failures, with an assumed weighted forced outage rate of 14.2% across the fleet, and low flexibility. The fixed operations and maintenance (FO&M) costs of keeping these systems in place is also high, with a weighted average FO&M of $32.73/kW-yr. This is significantly higher than the FO&M cost of new gas turbine or combined cycle technologies (~$11-13/kW-yr).[7] As a result, the scenarios also evaluated fossil retirements that could be achieved based on the amount of DER integration.

All generators included in the PREPA 2019 Plan Integrado de Recursos (IRP 2019)[8] were modeled and included for the purposes of this study unless otherwise specified in each scenario based on assumed retirements discussed in this section. Units specifically not included in the IRP due to maintenance or emission issues are excluded from this analysis and all scenarios.

To determine the order of retirement of fossil fired units, for all scenarios, weighted a combination of seven factors was developed, which included: Age, Emissions, Flexibility, Dependence on long-distance transmission (South to North), Fixed Operations and Maintenance Costs, Generation Costs (fuel costs, variable costs, etc.), and Reliability (forced outage rates). These factors, shown in Figure 3 were weighted based on the likelihood to help integrate additional renewable energy.

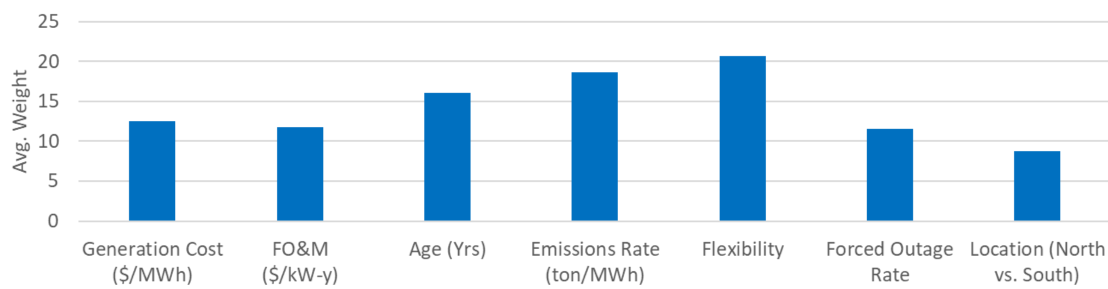

Figure 3: Retirement Analysis Weighting Factors

To determine the amount of retirements in each scenario, a screening resource adequacy analysis was conducted by randomly drawing sixty random outages for each generator and calculating the expected unserved energy. After solar and storage resources were added to each scenario, capacity was removed from the model based on the retirement order determined above until the Base Case reliability level (after accounting for reduced load from energy efficiency) was achieved. It should be noted that this was a screening analysis only and should not replace the required reliability analysis necessary to make retirement decisions.

However, the approach taken was conservative. It did not assume growth in PREPA's demand response program to 250 MW as required by PREB Order Number NEPR-AP-2020-0001. Based on this analysis, a retirement schedule was developed for each scenario and is shown in Table 2. By the 75% DER scenario,

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[7] National Renewable Energy Laboratory, 2020 Annual Technology Baseline, https://atb.nrel.gov/.

[8] PREPA, Plan Integrado de Recursos (Integrated Resource Plan) 2019, https://aeepr.com/es-pr/QuienesSomos/Paginas/ley57/Plan-Integrado-de-Recursos.aspx

2,300 MW of fossil generation is retired relative to nearly 5,000 MW of PV and 2,700 MW of battery energy storage added to the system. In addition, the solar and storage additions defer the need for any further new capacity despite the retirement of the above units.

Table 2: Scenario Retirement Schedule

Case	Units Retired	Incremental Capacity (MW)	Cumulative Capacity (MW)
Base Case	Not Applicable	0	0
25% DER	AES 1 & 2 and Palo Seco Steam 3 & 4	886	886
50% DER	Aguirre Steam 1 & 2	900	1,786
75% DER	Aguirre CC 1 & 2	520	2,306

2.4 A New Resource Mix for Puerto Rico

The combination of solar PV and battery additions and fossil generator retirements creates a resource mix that is fundamentally different than the one Puerto Rico has today. The total installed capacity by scenario is provided in Figure 4, which for the purposes of long-term planning is spread across a 20-year horizon as shown in Figure 5. On an installed capacity basis, solar and storage (inverter based resources) become the largest form of capacity by the 50% DER scenario and total installed capacity in Puerto Rico increases to over 10 GW by the 75% DER scenario, nearly double today's capacity despite increased energy efficiency.

This is a radically different resource mix and power system than what Puerto Rico has today, or the one proposed by PREPA in the 2019 IRP. From an engineering standpoint, such a fundamental change in the grid's resource mix can be achieved with current technology, but it requires detailed planning and grid simulation modeling like the work conducted in this study.

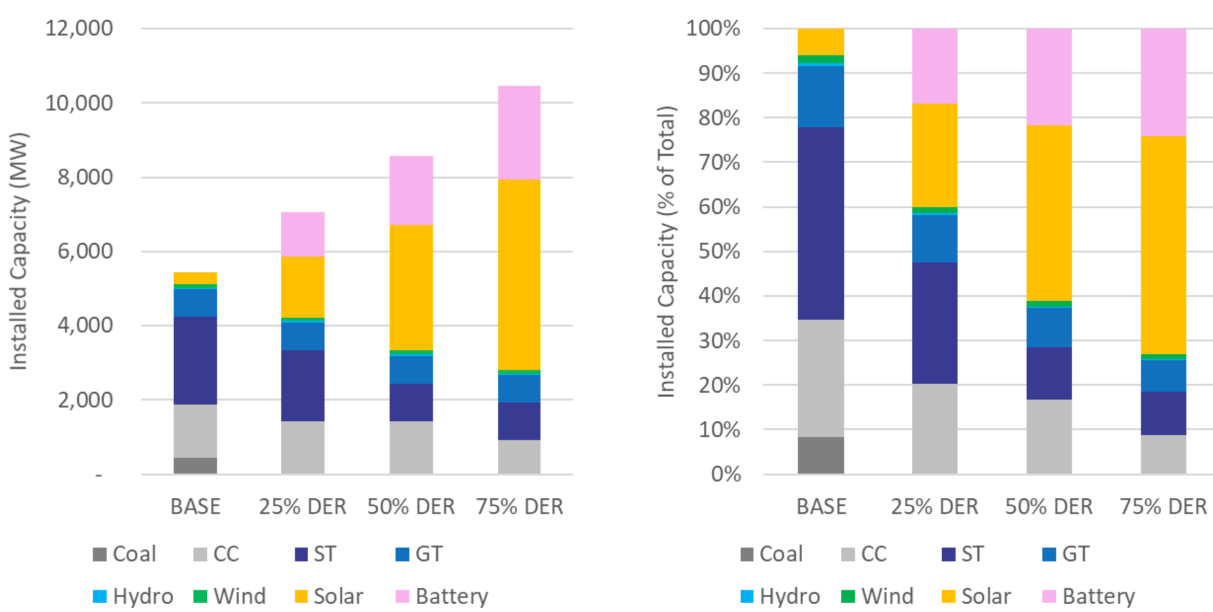

Figure 4: Installed Capacity by Scenario, MW (left) and % of Total (right)

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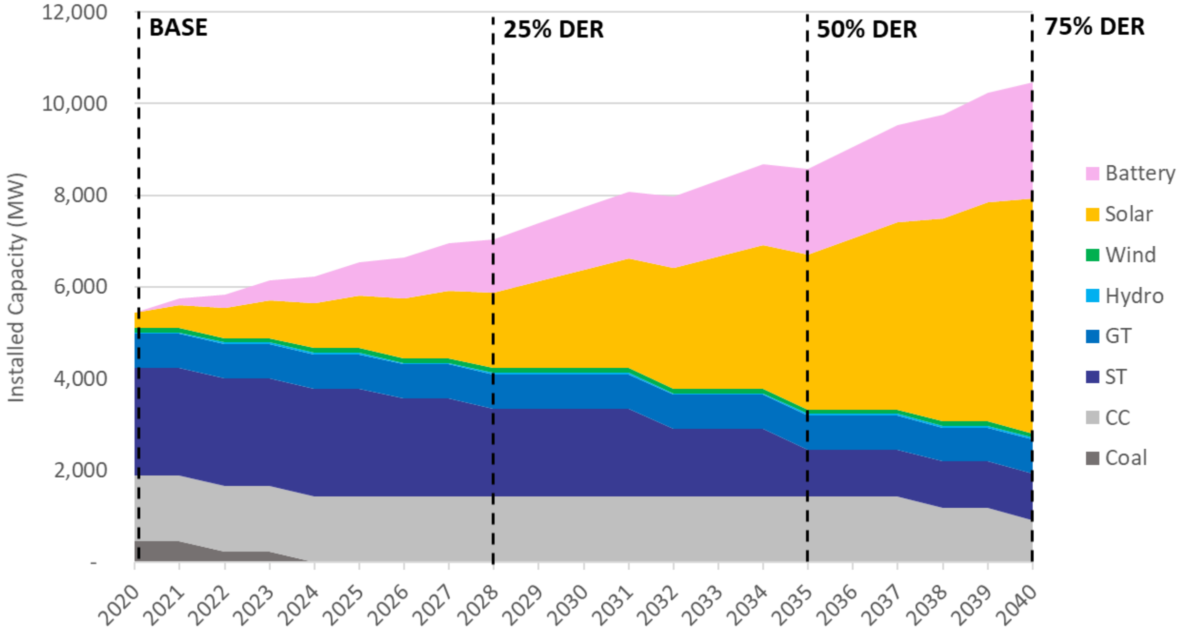

Figure 5: Installed Capacity by Forecast Year

3 Inputs & Assumptions

3.1 Network Topology

This study relied on a detailed representation of Puerto Rico’s transmission network based on network data provided by PREPA. Specifically, PREPA provided transmission models in Siemen’s PSS/E v33 format, and the Day Peak 2018 model was used. This model represents a snapshot in time, of what load, generator dispatch, and transmission flows look like during a mid-day peak load event. The Day Peak case was selected because it aligns with the period of solar generation analyzed throughout this study. This included a detailed representation of the transmission network topology, which include 8 regions, 1,234 transmission line branches, 181 transformers, and 860 load busses. The PSS/E power flow data included line impedances, line ratings, load allocation by bus, dynamic generator models, and other detailed network data.

The PLEXOS production cost model incorporated a full nodal transmission topology and monitored all transmission lines at the 38kV and higher level and load was allocated across the network on an hourly basis following the proportional allocation of load in the power flow data.

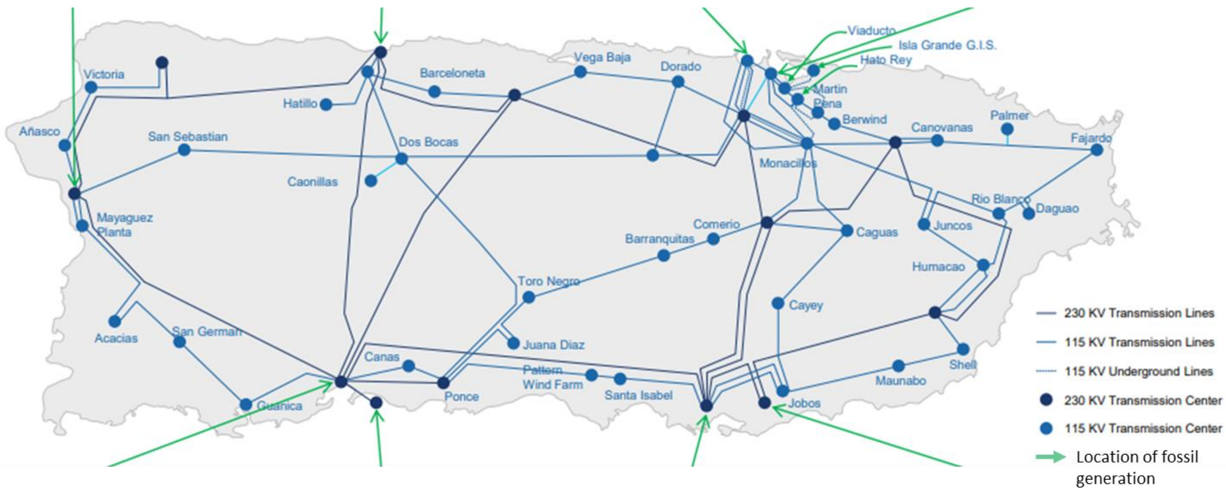

Figure 6: Puerto Rico High Voltage Transmission Topology

For planning and reporting purposes, the Puerto Rico power system is divided into nine planning regions used by PREPA and PREB. These include Arecibo, San Juan and surrounding Bayamón regions in the north, Carolina and Caguas in the east, Ponce OE (west) and Ponce E (east) in the south, and Mayagüez in the west. These divide the island based on location of major load busses and transmission interfaces between the regions. A map of the planning regions is provided in Figure 7.

Figure 7: Map of Puerto Rico Grid Planning Regions

3.2 Load & Energy Efficiency

Load and energy efficiency assumptions were crafted jointly with Energy Futures Group (EFG). EFG conducted the analysis to identify the necessary components of an energy efficiency program over the next 15 years to achieve the desired 25% reduction in load. However, for the purposes of this analysis the final energy efficiency value is most important, not the application of programs over time. For more information on the path and application of energy efficiency programs please refer to the companion report from EFG. The application of EFG's analysis in how it relates to this analysis will be covered in more detail below.

As for many of this study's inputs and assumptions, PREPA's 2019 IRP acted as the original data source and the project team utilized the base assumptions to the extent feasible. The 2020 gross energy demand for generation (Exhibit 3-11) from PREPA's 2019 IRP was used as the starting point for this study's own forecast. However, there is one change that was incorporated into the Gross Energy Sales (GWh) for 2020. The generation served by existing DPV installations was added back into the Gross Energy Sales amount this way the existing DPV capacity could be modeled as a generator instead of being imbedded in a lower load figure. Appendix 4 (Exhibit 3-1) of the IRP[9] along with the PREB Module[10] PV Approval List served as guidance for the level of existing DPV on the system. With the many economic and demographic changes Puerto Rico is undergoing load growth between 2020 and 2035 was assumed to be 0% or flat.

This means that the 25% energy efficiency target from EFG's analysis was simply applied to the total energy demand and peak load from 2020 to calculate the 2035 values. The breakdown of the load forecast and energy efficiency assumptions is found in Table 3. It is assumed that PREPA's own use will

[9] Puerto Rico Integrated Resource Plan 2018-2019, Appendix 4: Demand Side Resources, Exhibit 3-1
[10] Puerto Rico Energy Bureau, PV Modules approved by the Energy Bureau, https://energia.pr.gov/modulos-pv/

not be as affected by overall energy efficiency programs, so it was held constant across time. Even if it is reduced it is already a small component of the total energy and should not significantly change results.

Table 3: Total Energy Demand & Peak Load with 25% Energy Efficiency Reduction by 2035

Year	2020	2035
Gross Energy Sales w/ Existing DPV (GWh)	15,648	11,736
Technical Losses (GWh)	1,444	1,083
Non-Technical Losses (GWh)	830	623
PREPA Own Use (GWh)	34	34
Total Energy Demand w/ Existing DPV (GWh)	17,956	13,476
Peak Load (MW)	2,826	2,120

The total energy and peak load for 2035 were divided across the 8 study regions proportionally based on the regions respective total energy for 2020 from the 2019 IRP. This breakdown is shown in Table 4.

Table 4: Regional Breakdown of Total Energy (GWh) and Peak Load (MW)

	2035	
	Total Energy (GWh)	Peak Load (MW)
ARECIBO	1,338	211
BAYAMON	1,959	308
CAGUAS	2,158	339
CAROLINA	1,498	236
MAYAGÜEZ	1,502	236
PONCE ES	551	87
PONCE OE	1,089	171
SAN JUAN	3,382	532
TOTAL	**13,476**	**2,120**

Using the above total energy and peak load by region combined with a load profile that was shared by PREPA via their PROMOD database the Build function within PLEXOS was used to create a respective 8760 hours per year load profile for each region that matched the total energy and peak load inputs. The resulting profiles were then used across all simulations. Load was then allocated at each individual load bus based on the proportional allocation in the PSS/E power flow data.

3.3 Generator Characteristics

All major generator characteristics and parameters were modeled to match what is used in the 2019 IRP. This includes assumptions for max capacity, fuel type, ramp up, ramp down, forced outage rates, fixed operation and maintenance costs, and variable operation and maintenance costs.

Although the IRP also specified minimum up and down times along with minimum stable levels, some of these figures were conservative and not in line with what is common in other grids. Based on this some units have more flexible min up and down time parameters and min stable levels than the IRP outlines. This assumes that over the next 15 years these units will receive the required investment to keep them running and bring their operation up to the level other similar units already have in 2020.

Additionally, only the full load heat rate was shared in the IRP. Using the minimum stable level, maximum capacity, and full load heat rate for each respective unit and a default heat rate curve that differed for each unit type (i.e. CC, ST, GT) a polynomial heat rate curve was calculated for each unit (Appendix, Table 19, Figure 63). The polynomial heat rate curve was used within the production cost modeling simulations. This allows for a more accurate representation of a unit's dispatch as opposed to simply modeling the full load heat rate.

Lastly, while the IRP reported forced outage rates, it did not report maintenance rates. The maintenance rate for all units were based off the NERC Generating Availability Data System (GADS) dataset.[11] The NERC GADS dataset includes average generator reliability by unit type and fuel type.

No new unit additions have been added outside of the solar and battery installments discussed in Section 2.2. But 50 MW of utility scale solar projects were added to the model that were not included in the IRP because they were built or started construction in the interim period.

3.4 Fuel Prices

Fuel prices are taken directly from what the IRP used for its fuel forecast. These can be found Table 5.

Table 5: Fuel Prices (real 2020 $/MMBtu)

Year	Coal	Diesel	Fuel Oil	Natural Gas
2035	2.65	17.42	12.92	7.84

3.5 DER Representation & Characteristics

The DER represented on the power system included distributed PV (DPV), distributed BESS (dBESS), and distributed demand response (DR). These were captured in the model at 288 different 38kV buses throughout all PREPA areas of the power system. The distribution at each bus was chosen to be proportional to the distribution of load across the buses for a given PREPA area, as provided in the original PREPA base case. This allowed the levels of DER to vary by PREPA area while still be distributed across individual buses in a reasonable and consistent manner.

[11] PJM, 2018 PJM Reserve Requirement Study, https://www.pjm.com/-/media/planning/res-adeq/2018-pjm-reserve-requirement-study.ashx?la=en

Demand Response and Load Representation

The demand response service is considered to be relatively long-duration (hours) and slow-acting (minutes to hours of advanced notification) such that it is represented in the transmission model as a reduction in load.

The load across the system was originally provided from the power flow model as static loads with constant P and constant Q values. For representation in the dynamic model, the load was represented as 75% static load and 25% dynamic load by MW. The static portion of the load was represented as a constant active current and constant reactive impedance. The constant active current representation is a compromise that captures a mix of constant power and constant impedance loads that are assumed to physically be on the system, while a constant reactive impedance is a reasonable representation of the majority of physical loads.

The dynamic portion of the load was represented by a composite load model (CMLDBLU1) that contains representation of a feeder transformer, feeder impedance, power-electronic loads, and four different types of aggregate motor loads, as shown in Figure 8. This model was developed by power system stakeholders in the Western US to better capture the impact of induction motor-driven compressor loads like those found in three-phase and single-phase air-conditioning systems. The composite load model is parameterized for typical residential and light commercial loads. For further improving the diversity of the load representation, four different sets of parameters were developed with slight variations to important settings like contactor opening and reclosing voltage thresholds and timers. The behavior of motor-driven loads is particularly important when assessing the stability of the grid for fault events, and it cannot be reasonably neglected. However, it is acknowledged that accurate dynamic load modeling is very difficult to achieve and continues to be a work-in-progress by the industry, as it has been for decades.

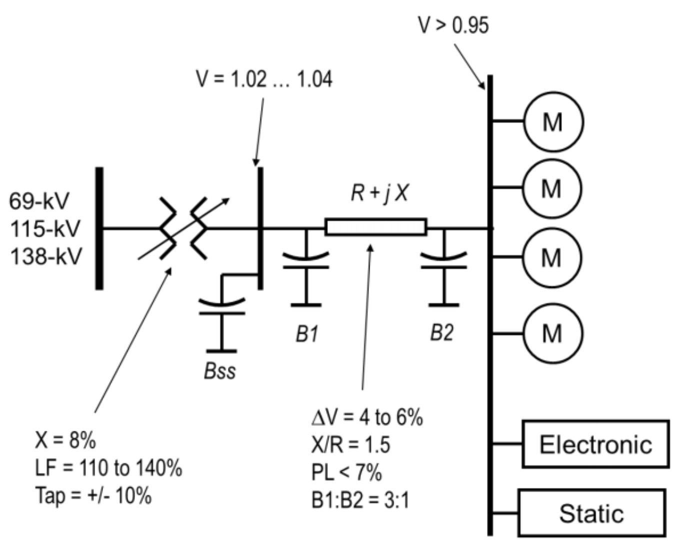

Figure 8: Composite Load Model Overview

Distributed PV and BESS Representation

The DPV and dBESS are both represented by a generic renewable energy model for distributed resources (DER_A). This model was developed in recent years and has gained increasing use across the US for representing distributed inverter-based renewables like solar PV and battery systems, which are capable of both sourcing and absorbing active and reactive power. This dynamic model also contains frequency-response and volt-var response functions (often referred to as "smart inverter" features), which can be enabled and adjusted to allow the DER to provide essential reliability services to support the grid.

The inverters for PV and BESS are extremely similar in reality, and therefore, the PV and BESS is represented as a single DER_A model at each of the 288 38kV buses. The active power of the model is set to be the sum of the DPV and dBESS contributions as specified by PLEXOS, where positive values for dBESS are for discharging operation and negative values are for dBESS charging. Therefore, it is possible that for some hours in the high-penetration scenarios, the DER will have a net negative power, indicating that the BESS charging rate exceeds the PV generation at that time.

Model Linkage – Production Cost, Transmission, and Distribution

The grid is represented and analyzed at the transmission level by PSSE and at the distribution level by OpenDSS. To align these models, both are fed data from the production cost simulation model, which specifies the level of active power for the load, DR, DPV, and dBESS for each hour of each scenario evaluated. This is shown by the large blue arrow in Figure 9. The distribution model contains detailed feeder topologies and a simple equivalent representation of the grid beyond the 38kV bus. To ensure consistency between the transmission and distribution models, the Thevenin Equivalent source for grid representation at the distribution level was calculated for each load bus in PSSE. Finally, the voltage at the 38kV buses forming the interface between transmission and distribution models is considered decoupled by the on-load-tap-changer at each feeder transformer, where the voltages in steady-state are regulated by the feeder transformer to achieve a desired low-side voltage given the power flows on the feeder at the time.

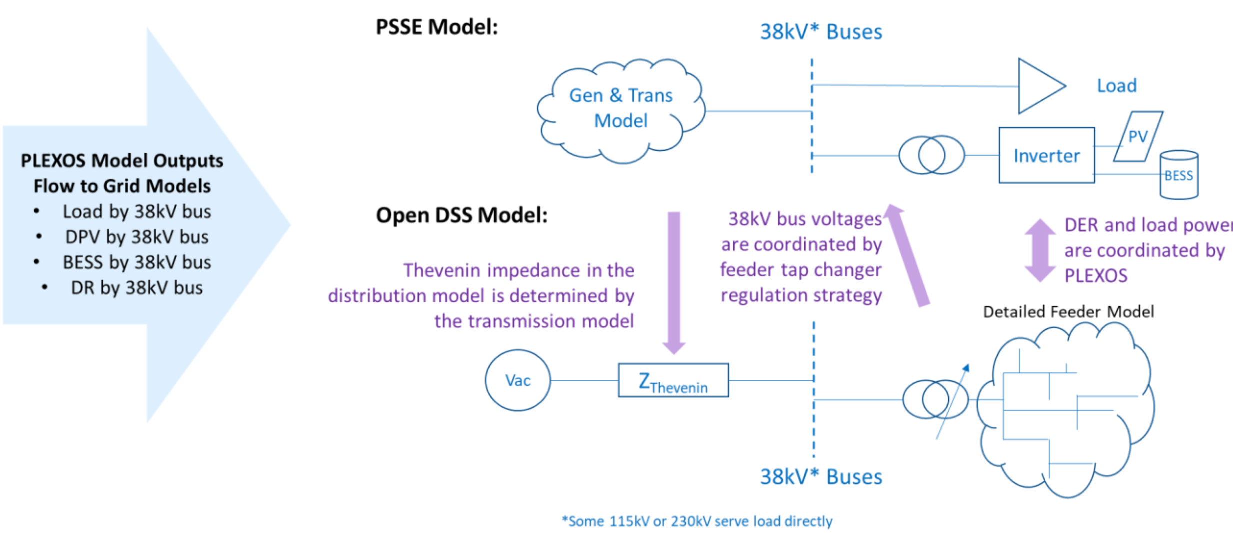

Figure 9: Linkages of Models Representing the Puerto Rican Grid

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DER Aggregation and Control

In addition, it was assumed that the DER was integrated with some level of coordination and control. This would allow the system operator could take into account expected generation from DER resources to commit and dispatch the system and schedule battery energy storage, at least in part, based on system needs. This study was a system-level analysis and did not evaluate the potential for conflicting needs of behind-the-meter solar and battery energy storage optimized for both individual and system use. This is a reasonable assumption because while it would be impossible to simulate each individual system, when viewed at the system-level there will be surplus capacity available to use for grid services.

It was also assumed that distributed battery storage in this analysis is able to provide grid spinning reserve requirements through an aggregator that coordinates the output of many DER assets to provide controllable grid services. If this is not technically achievable in the short-term due to technology limitations of broad communications and coordination challenges, there may be a need for increased spinning reserves, which were not evaluated for this study.

In addition, because the residential solar PV was integrated as hybrid systems with coupled battery energy storage, this study also did not include an increase in reserves, above current requirements, due to either the variability or uncertainty of solar resources. The study used the reasonable assumption that the solar and battery resources could “self-regulate” and manage net-to-grid variability via ramp rate limits or other inverter controls. For example, if the solar is back-feeding onto the distribution circuit during mid-day operations, a drop in the solar output would be mitigated by a short term increase in battery storage output to minimize any rapid change in rooftop PV output.

4 Characterizing Puerto Rico's Solar Resource

4.1 Solar Irradiance Data and Power Production Profiles

To accurately simulate a power grid with high distributed solar integration, it is important to properly characterize solar variability across timescales that vary from sub-hourly to seasonally. While using actual measured data at existing solar plants can be useful to characterize solar variability at an individual plant, it is inadequate for full system evaluations and high solar integration studies. This is because it is important to accurately capture geographic diversity. As solar integration increases across Puerto Rico it will be spread out across the island. While any individual solar site may have a large amount of variability due to cloud cover, the island-wide variability will be significantly reduced. For this reason, this study utilized simulated historical solar data instead of actual measured plant output.

The data source for the chronological solar irradiance data was the National Solar Radiation Database (NSRDB) from the National Renewable Energy Laboratory (NREL). The NSRDB is a serially complete collection of hourly and half-hourly values of meteorological data and the three most common measurements of solar radiation: global horizontal, direct normal and diffuse horizontal irradiance spanning 21-years of historical weather.[12] The NSRDB also has a specialized dataset for Puerto Rico – the Puerto Rico Simulated High Resolution Dataset[13] – that was utilized for this study to also include weather data at 5-minute resolution.

The irradiance data was then converted to power production profiles using the NREL System Advisor Model (SAM). The System Advisor Model (SAM) is a free techno-economic software model that can simulate a wide variety of renewable energy systems. For this project, SAM was used to model the power production of distributed rooftop and utility-scale photovoltaic systems. Using the weather data collected from the NSRDB and plant characteristics - like DC:AC ratios, tilt, azimuth, etc. – chronological power production profiles were developed for use in the PLEXOS model. Assumptions used to develop power production profiles are provided in Table 6 for distributed rooftop PV systems. While each PV system will have unique attributes, these assumptions are meant to represent the weighted average of all systems in Puerto Rico. Existing utility-scale projects utilized similar properties, but assumed a DC to AC ratio of 1.3, and a specific plant capacity and location.

Table 6: Photovoltaic System Design

Property	Assumption
DC:AC ratio	1.1
Inverter Efficiency	96%
System Losses	14%
Racking	Fixed-axis roof mount
Tilt	18 degrees
Azimuth	180 degrees

[12] National Renewable Energy Laboratory, National Solar Radiation Database, https://nsrdb.nrel.gov/
[13] National Renewable Energy Laboratory, Puerto Rico Simulated High Resolution Dataset, https://developer.nrel.gov/docs/solar/nsrdb/puerto-rico-download/

4.2 Geographic Diversity & Site Selection

One of the benefits of DERs over utility-scale projects is the geographic diversity benefits gained through thousands of distributed systems across the island. While this study did not attempt to simulate the chronological solar power production of each individual rooftop PV system, it did incorporate a large dataset of solar locations spread across Puerto Rico's population centers.

For this analysis, 96 sites were selected across Puerto Rico, concentrated in developed areas where residential and commercial PV systems would be most prevalent. For the initial site selection PREPA's transmission busses were mapped using GIS data provided by PREPA. This provided locations of existing transmission and distribution infrastructure. Twelve sites were then selected for each of the eight regions (Figure 7) based on the density of urban development and existing transmission and distribution infrastructure. This created 96 sites total (8 regions and 12 sites per region) across the island, which were clustered around urban and suburban load centers to weight solar generation to those regions. A map of the 96 selected solar sites, colored by region, is provided in Figure 10 and annual capacity factors by site are provided in Figure 11. In general, capacity factors are highest along the coast and at lower elevations away from the mountainous interior.

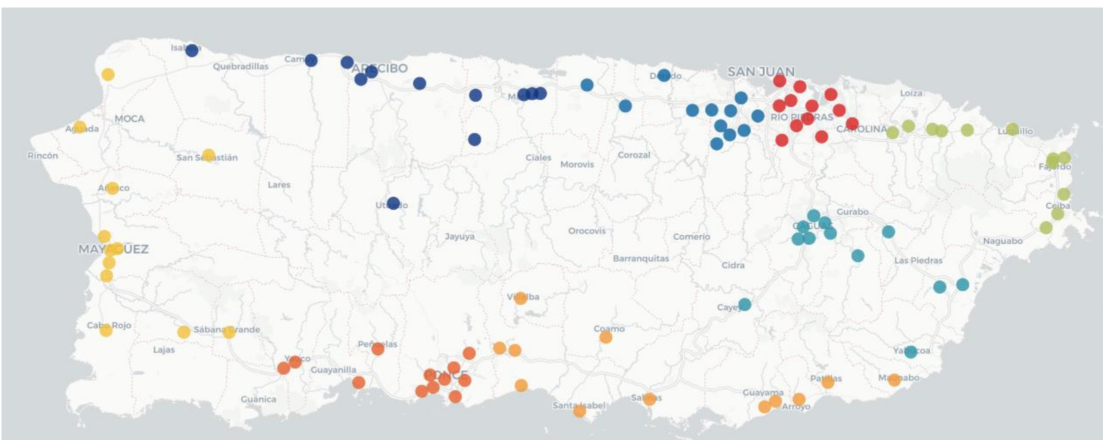

Figure 10: Map of Simulated Solar Locations Across Puerto Rico
(colored by region)

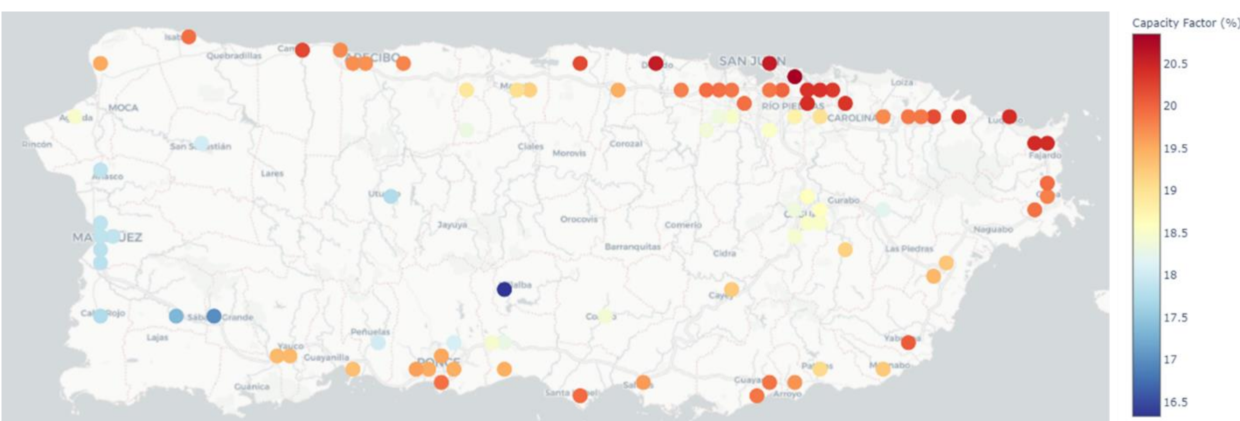

Figure 11: Map of Solar Capacity Factors Across Puerto Rico
(colored by annual capacity factors)

For each of the 96 sites identified a full year of chronological, 5-minute resolution weather data was downloaded from the NREL Puerto Rico Simulated High Resolution Dataset and converted into power production profiles. This generated over 10 million data points of chronological solar data that were modeled for the study to ensure adequate geographic diversity and granular chronology of variability. The data was then aggregated for each region by averaging the twelve sites into a single composite regional profile for use in the production cost modeling.

An example of the geographic variability is provided in Figure 12 which shows the five-minute solar capacity factors for three regions across one day of operation, as well as the island-wide average. The two regions in close proximity, Caguas and Ponce ES, both are characterized as cloudy days with solar PV decreasing availability in the afternoon hours. Mayagüez, which is in the westernmost side of the island is experiencing a relatively sunny day. The average of all eight regions (dotted line) shows a somewhat smoother profile. This data is quantified in the correlation matrix in Figure 13, which is a measure of alignment in the chronological profile. This plot shows that regions in close proximity have higher solar profile correlations.

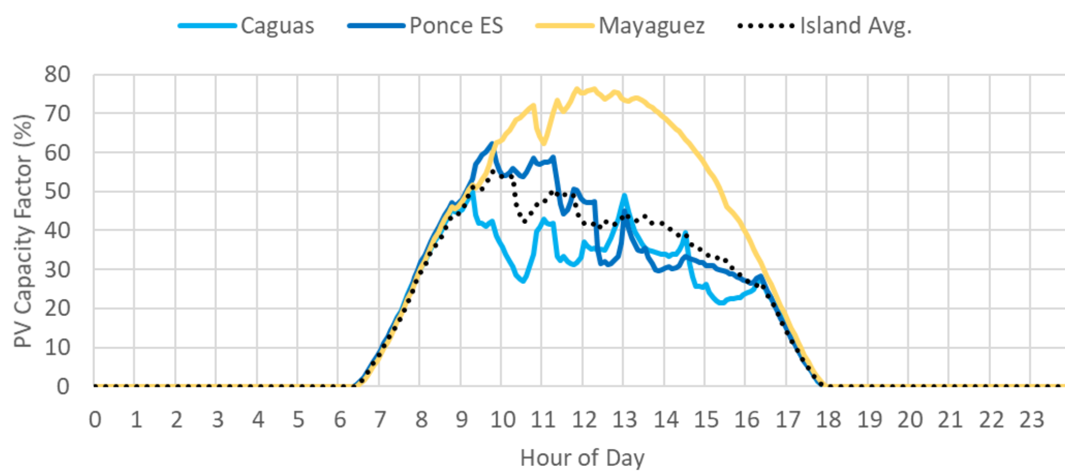

Figure 12: Sample Day of Solar Variability by Region

West → East

	Mayaguez	Arecibo	Ponce OE	Ponce ES	Bayamon	San Juan	Caguas	Carolina
Mayaguez	1.00							
Arecibo	0.87	1.00						
Ponce OE	0.86	0.86	1.00					
Ponce ES	0.85	0.88	0.94	1.00				
Bayamon	0.81	0.91	0.83	0.88	1.00			
San Juan	0.81	0.89	0.83	0.89	0.95	1.00		
Caguas	0.80	0.87	0.86	0.92	0.90	0.91	1.00	
Carolina	0.80	0.89	0.84	0.89	0.91	0.93	0.93	1.00

Figure 13: Correlation Matrix of 5-Minute Chronological Solar Profiles

While the previous maps show the locations selected for simulated weather data, the installed PV capacity were sited based on existing residential and commercial load locations. The data source for the load was the PSS/E power flow network data, which provided the load at each load bus across the system. Load busses were classified by type (residential, commercial, industrial, agriculture, etc.) and assigned to each of the load regions. For the purposes of this study, it was assumed that current and future residential and commercial distributed PV was sited proportional to the load of that type. The PV capacity was then distributed across the system, interconnecting at 289 distinct transmission busses.

The breakdown of load and DER capacity by region is shown in Table 7 and Figure 14. Because San Juan has the largest amount of commercial and residential load, it was also assumed to have the most installed DER capacity. A complete breakdown of the DER capacity, both solar PV and battery, by region, customer class, and scenario is provided in the Appendix, Table 20.

Table 7: Allocation of Residential and Commercial Load & DER by Region and Customer Class

Region	Residential Load (MW)	Commercial Load (MW)	Other Load (MW)	Residential DER (%)	Commercial DER (%)
Arecibo	124	63	83	10%	8%
Bayamón	237	66	77	19%	9%
Caguas	205	101	109	16%	13%
Carolina	157	69	58	12%	9%
Mayagüez	140	113	39	11%	15%
Ponce ES	49	25	105	4%	3%
Ponce OE	109	43	83	9%	6%
San Juan	245	277	129	19%	37%
Total	**1267**	**756**	**682**	100%	100%

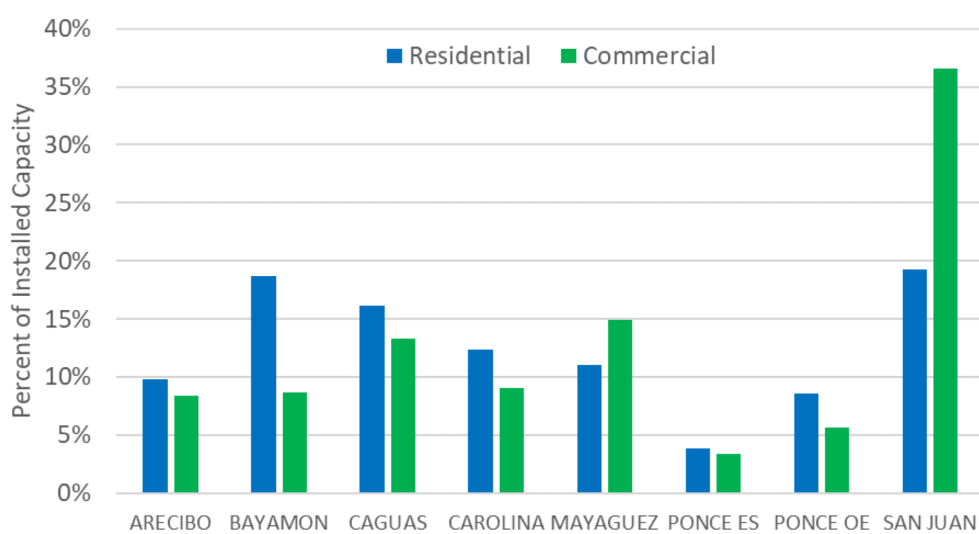

Figure 14: Allocation of Residential and Commercial DER by Region and Customer Class

5 Generation & Production Cost Modeling Results

5.1 Grid Operations with High DER

Grid operations change markedly as the system moves towards a higher penetration of DER. Figure 15 highlights how annual generation by unit type changes over the four reference results. As solar generation increases it displaces fossil fuels on the grid. The types and amount of fossil fuel displacement depends on the costs, flexibility, and physical characteristics of each generating unit. The retirement of AES in all but the Base Case stands out with the coal unit type denoted by a dark gray. The immediate result of a system without AES and a 25% integration of DER is an increased role for existing combined cycle (CC) plants. The 25% DER case shows much of the generation once provided by AES is instead produced by existing combined cycle plants, which operate on either LNG or oil fuels. These existing combined cycle plants include both EcóElectrica and the two San Juan CC units, all of which can increase generation from what is dispatched in the Base Case.

As the penetration of DER increases in the 50% and 75% DER cases, solar takes on a much larger role and begins to displace steam turbine (ST) units and later CC units. While simple-cycle gas turbines (GT), also referred to as "peakers," generate a relatively low amount of generation in the base case, their role in total generation is reduced further in the 50% and 75% scenarios as battery energy storage effectively reduces peak loads.

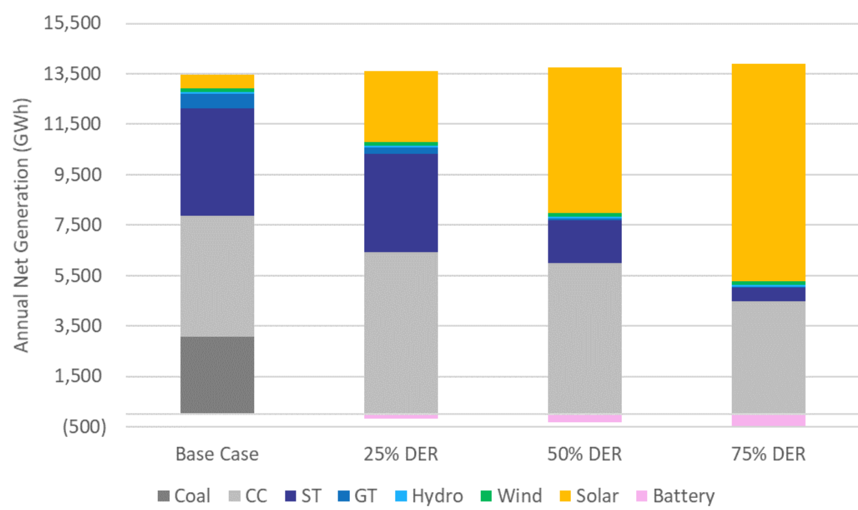

Figure 15: Annual Net Generation by Unit Type

It should be noted in this chart that the 25%, 50%, and 75% values do not necessarily equate to the percentage of total generation. This is because the scenarios were developed based on energy *sales*, which does not take into account transmission losses, distribution losses, non-technical losses (theft), PREPA self-use, round-trip energy losses associated with battery storage utilization, or curtailment. These components of total energy demand are included in Table 3.

Another way to highlight the change across the cases is to compare the displacement of generation (Figure 16) which represents the net *change in generation* in each scenario, relative to the Base Case. Resources that are increasing the amount of generation they contribute are on the positive side (or right side of x-axis) and those that are being displaced by the new resources are shown on the negative side (or left side of x-axis). It is important to note that battery resources are on the left side due to the round-trip efficiency losses inherent with the technology. As the battery buildout increases with increased penetration of DERs the amount of round-trip losses increases as a result of their increased usage.

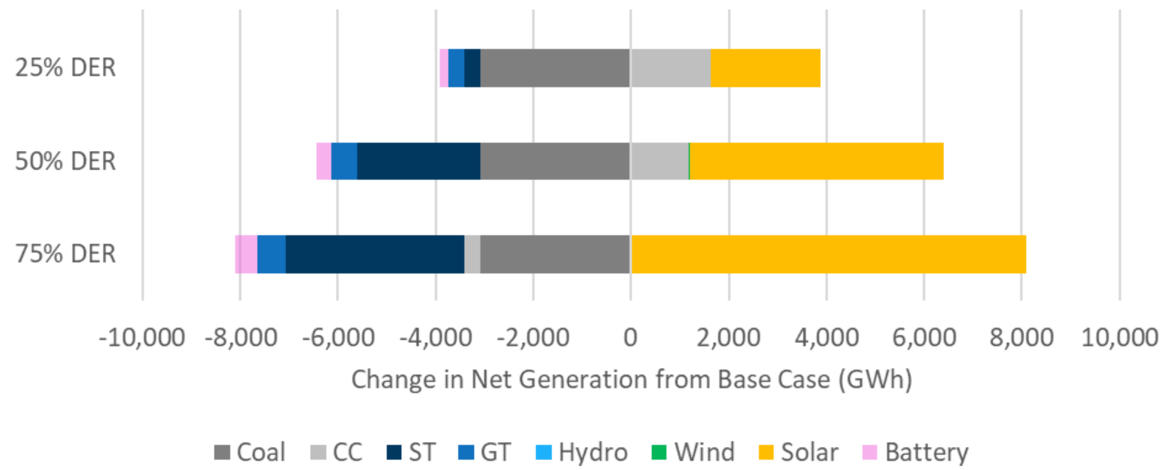

Figure 16: Displacement of Generation by New Resources when compared against Base Case

While annual generation and displacement values are important for public policy and long-term system planning, it provides little information on day-to-day, hourly, or sub-hourly operations. Because system load changes from hour-to-hour, and solar resources are variable, understanding *chronological* generation by unit and resource type is critical. The production cost analysis performs a chronological commitment and dispatch of the power grid to minimize system cost – in a similar fashion as the grid operator (PREPA). The commitment determines which units should be online while dispatch determines the MW output from each generator.

The below dispatch diagrams in Figure 17 show a relatively "normal" day of operation for each respective case. The dashed black line shows the load level for each given hour. Battery storage is depicted as two shades; when the battery storage (dark pink) is above the black line it is charging, and when it is directly below the black line (light pink) the battery storage is discharging.

There is no storage installed in the Base Case, but as storage is added in the 25% DER scenario the use of GT units drops as their generation is now mostly covered by battery storage. The role of conventional "baseload" generation shifts from the AES coal plant in the Base Case to the combined cycle units in all the following cases. Because these resources represent the least cost form of fossil generation, they are utilized as much as possible to avoid generation from higher cost resources.

As DER penetration increases along with the buildout of battery storage, battery storage fulfills a larger portion of load during the morning and evening hours. As mentioned above by first displacing GT unit generation but by the 75% DER case most of the generation formerly provided by ST units is also replaced by Storage.

With this increase in DER, solar and storage becomes the largest resource on the system in most hours of the day, with CC – and to a lesser extent ST – fossil units dispatching in the morning and evening hours when solar generation is reduced. The peak solar hours of the day are not only the prime hours for charging the battery storage resources but also the hours where most fossil fuel-based generation is either reduced to lower loading levels or turned off entirely. This is most noticeable in the 75% DER case where all generation, save a small portion of combined cycle generation, is displaced during the middle of the day by solar. It is important to note that this is happening even with a large amount of solar generation being directly charged by battery storage for use at a later time.

The decision to turn down a generator or entirely turn off a generator is based on several variables, including the resource's start-up and shutdown costs, minimum loading level, spinning reserve requirements, and expected amount of time the generator can be turned off for.

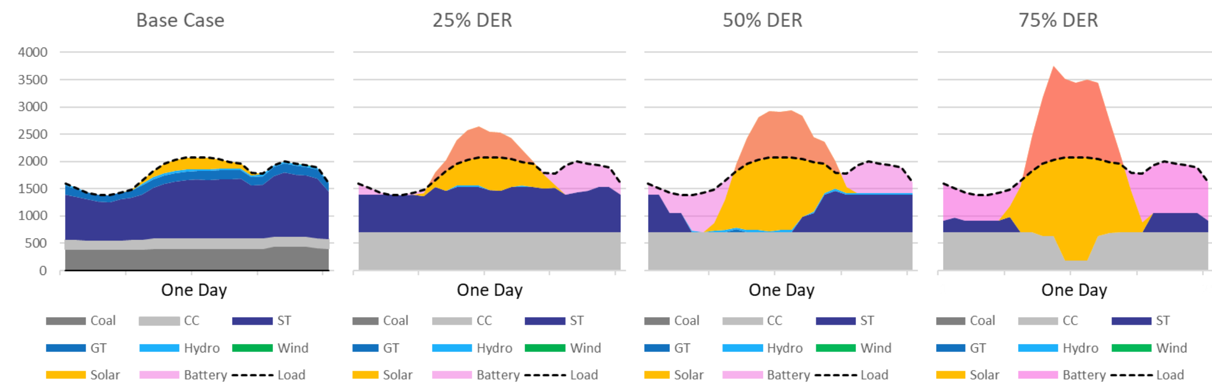

Figure 17: Dispatch Diagrams for "Normal" Day

While Figure 17 shows a single day of operation across the four scenarios, commitment and dispatch decisions must be made taking into account what occurred previously, and what will occur afterwards. To illustrate this, dispatch diagrams showing weeklong periods are provided in Figure 18 and Figure 19. These two weeks were selected to highlight how the system operates during the period of peak load and during the week with the most amount of renewables generation. In Figure 18 the Base Case heavily commits ST and GT units to meet load even with the presence of the AES coal unit providing a fixed output. While in the 75% DER case, which has retired AES and other thermal units, the ST and GT units are rarely operated despite this representing the week with the highest demand. Instead solar combined with batteries can sufficiently meet load with selective use of ST and GT units in evening hours – even on lower solar days.

The trends in chronological generation are even more apparent during the week of highest renewable generation, as shown in Figure 19. The Base Case relies on ST units every hour of the week, but as DER penetration increases this reliance declines. By the 75% DER case ST units are only dispatched two evenings of the week and GT units are barely called on at all. Overall, each of these weeks show that solar in combination with batteries can supplant an array of thermal generation, from oil-fired peakers like GT units to units that more traditionally provide baseload power like ST and CC units. These two samples highlight how DER is able to operate the system during its peak demand periods and how the system can fully take advantage of renewable generation. For additional weekly dispatch illustrations please see the Appendix.

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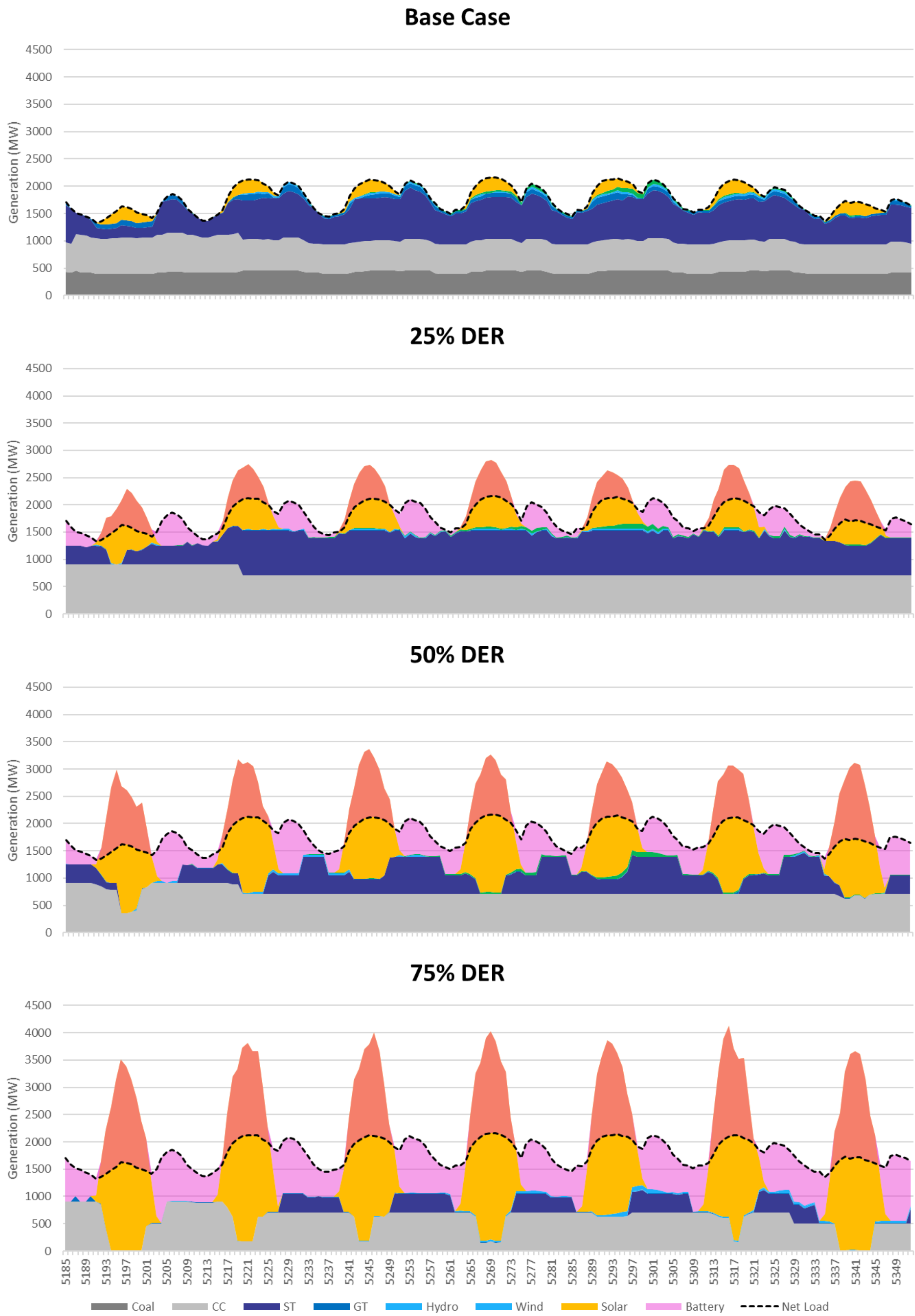

Figure 18: Dispatch Diagrams, Peak Load Week (Aug 5)

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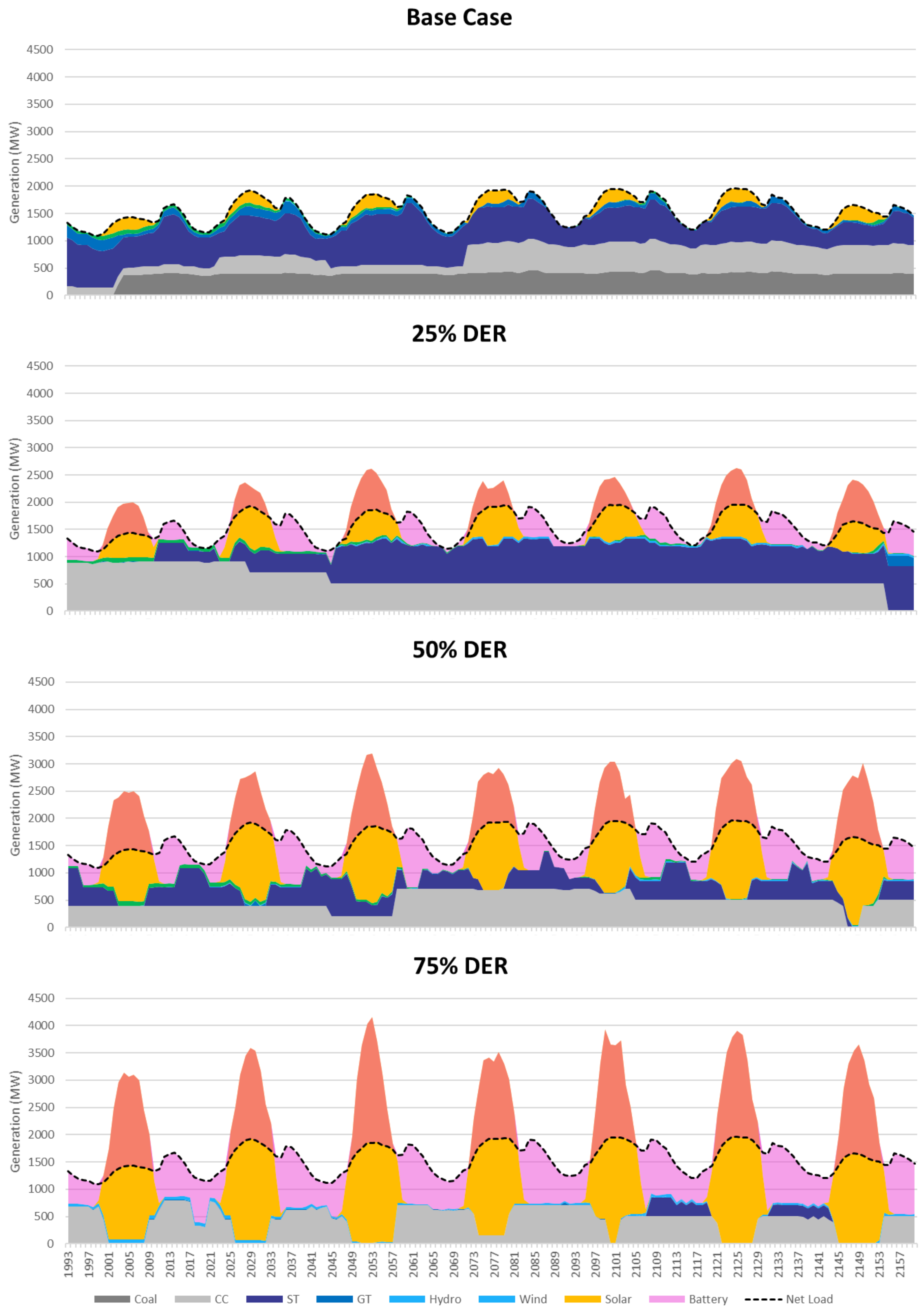

Figure 19: Dispatch Diagram, Maximum Renewables Generation Week (Mar 25)

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The overall trends visible in the dispatch diagrams are also apparent when looking closer at hours online and unit cycling across the entire study year, not just one day as the dispatch diagrams focus on. Figure 20 shows the average starts per year (left) and average number of hours online per unit for each unit type (right) across the four scenarios. From these figures, the following observations can be made:

- Due to the retirement of AES in all but the Base Case its average hours drop to zero.
- Similar to trends highlighted in the dispatch diagrams, both the hours and starts of GT and ST units drop with increased penetration of DER. GT units experience their biggest drop between the Base Case and 25% DER case.
- Combined Cycle units are the only unit type that experiences as noticeable uptick in number of starts and hours online. This is because the CC fleet takes on much of the cycling duty (turning off and on) in the higher DER scenarios and most other generation is displaced entirely.
- The chart illustrates the increased flexibility required by the fossil fleet, especially for the CC units, which will be expected to cycle on and offline more often and run for fewer hours per year. This may change the maintenance requirements, cycling costs, and reliability of these generators in the future.

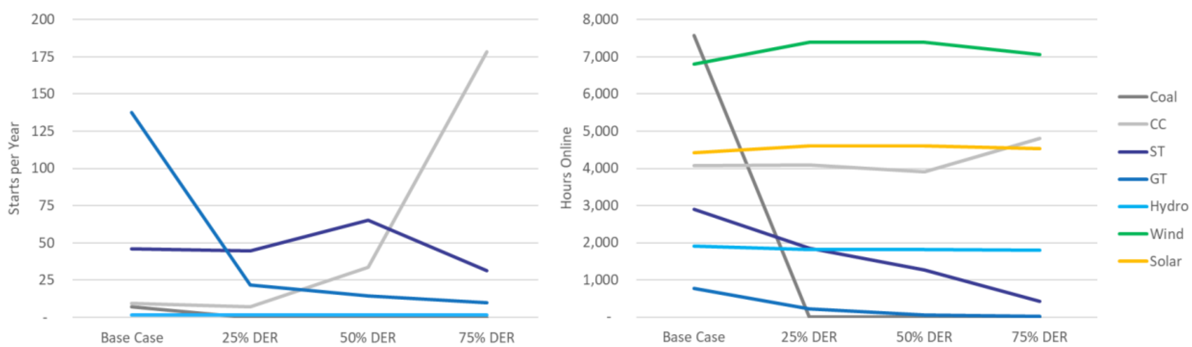

Figure 20: Average Starts (left) and Hours Online (right) per Year by Unit Type

It is not only the generation of the fossil fleet that is displaced. In addition, the DER also provides the grid's spinning reserves. These reserves represent generation that is held back in reserve by generators to meet unexpected drops in generation (contingency reserves) or normal fluctuations of load and solar resources. As discussed in Section 3.5, this study assumed that DER did not require additional reserves because it was added with battery storage and thus does not add net-variability to the system. It was also assumed that DER could be aggregated and provide grid services in a controllable manner.

Despite considerable changes in how the grid operates as the penetration of DER is increased there were no challenges associated with meeting reserve requirements. In fact, reserve shortfalls are eliminated in scenarios with DER integration. For example, the Base Case does experience a shortage of spinning reserves that amount to about 0.2% of total risk and occur during 4.1% of all hours. Many grids currently rely on fossil fuel-based generation to meet reserve requirements but with the addition of large amounts of storage to the grid, these new resources can begin to play a larger role in the provision of grid services.

5.2 Avoided Fuel, Emissions, and Generation Cost

The changes to generation and displacement of fossil fuels presented in Section 5.1, leads directly to reduced fuel consumption and fuel expenditures. This is an important benefit of DER, as it reduces reliance on imported fuels, emissions, and expenditures that flow out of Puerto Rico. The metrics presented in this section also provided valuable benchmarks to measure the *benefits* of DER integration, including avoided generation cost and avoided emissions. These avoided costs represent a shift from variable expenses (largely fuel) to fixed costs (mostly capital cost and maintenance for new DER equipment).

Changes in fuel consumption closely mirror the changes in generation discussed in the previous section. Table 8 shows the annual fuel consumption by fuel type in terms of MMBtu and the more fuel specific unit (i.e. barrels, bbls, for oil). Coal consumption ends with the retirement of AES and oil consumption declines with the addition of more DER. While gas experiences an increase versus the Base Case in the 25% DER scenario, which can be met by existing facilities, as gas-powered generation increases to replace generation once coming from AES. But gas consumption then declines as it is displaced by solar + battery in later cases. Overall, oil and gas both experience more than a 50% decline in consumption by the 75% DER scenario in addition to the 100% decline in coal consumption that all DER scenarios include. As a result, Puerto Rico would be less susceptible to fuel price volatility and would become more energy independent with increased DER adoption. This reduction in fuel consumption also translates to a more than 70% reduction in carbon dioxide emissions by the 75% DER case.

Table 8: Annual Fuel Consumption and Emissions by Scenario

		Base Case	25% DER	50% DER	75% DER
Consumption (MMBtu)	Coal	30,095,500	-	-	-
	Oil	28,868,900	24,086,510	19,235,470	12,613,700
	Gas	58,462,330	65,887,810	44,084,710	27,454,930
Consumption (fuel type units)	Coal (short tons)	1,544,151	-	-	-
	Oil (bbls)	4,884,857	4,146,285	3,326,911	2,182,950
	Gas (BCF)	58.46	65.89	44.08	27.45
Carbon Dioxide Emissions (tons)	Total	8,892,978	5,806,914	4,131,259	2,623,456
Change from Base Case					
Consumption (MMBtu)	Coal		(30,095,500)	(30,095,500)	(30,095,500)
	Oil		(4,782,390)	(9,633,430)	(16,255,200)
	Gas		7,425,480	(14,377,620)	(31,007,400)
Carbon Dioxide Emissions (tons)	Total		(3,086,064)	(4,761,719)	(6,269,522)
Percent Change from Base Case					
Consumption (MMBtu)	Coal		-100%	-100%	-100%
	Oil		-17%	-33%	-56%
	Gas		13%	-25%	-53%
Carbon Dioxide Emissions (tons)	Total		-35%	-54%	-70%

Overall, as DER is integrated the total production costs decline across the cases evaluated. Production costs, also referred to as variable costs, measure fuel expenses, variable operations and maintenance (VO&M) costs, and startup/shutdown costs. Production costs do not include fixed costs, including capital costs, fixed operations and maintenance (FO&M) costs, or costs to build and maintain the transmission and distribution network. It should be noted that this report does not evaluate the additional costs but defers that discussion to a subsequent report provided by Energy Futures Group which was developed in conjunction with this analysis.

As shown in Table 9 total production costs decrease significantly as DER is integrated on the system. The vast majority of the cost reductions come from decreased fuel costs, while VO&M cost is also reduced. Start costs, which were included to estimate both the startup fuel, as well as increased maintenance and degradation, increase slightly in the 25% and 50% DER scenarios, but start to decrease in the 75% DER scenario. System-wide start costs were calculated by categorizing each unit's starts as hot, warm, or cold depending on its unit type and applying the respective capital and maintenance costs, startup fuel costs, and auxiliary power and operations costs from NREL.[14]

The savings from introducing more DER onto the grid while also retiring fossil fuel-based generation are considerable. Table 9 shows that the savings range anywhere from roughly $97 million to $613 million per year.

However, these savings – in addition to other benefits like avoided capacity costs, potential transmission and distribution deferral, avoided emissions, and resiliency benefits - would have to be used to offset the capital costs associated with new capital expenditures for the DER PV and battery capacity, as well as associated distribution upgrades.

These savings can also be viewed as not only absolute dollars but also from the perspective of savings per additional total available solar measured as ($/MWh). To calculate this, divide the savings from Table 9 by the additional total available solar energy in MWh for each respective case versus the Base Case. The results show that there is a savings of between $43 and $75/MWh per additional solar on the system.

Table 9: Total Production Costs and Avoided Energy Costs (all costs are in real 2020 dollars)

	Base Case	25% DER	50% DER	75% DER
Fuel Cost ($000)	1,002,788	926,212	677,269	432,365
VO&M Cost ($000)	59,143	32,059	20,756	12,890
Start Cost ($000)	23,899	30,886	33,510	27,739
Total Production Cost ($000)	**1,085,830**	**989,158**	**731,534**	**472,994**
Difference to Base Case ($000)	N/A	96,672	354,296	612,836
Savings per Additional Solar ($/MWh)	N/A	43.27	68.23	75.27

[14] National Renewable Energy Lab, Power Plant Cycling Costs, https://www.nrel.gov/docs/fy12osti/55433.pdf

On a unit type basis the majority of the savings between the Base Case and DER cases is from reduced costs on coal, ST, and GT units, as shown in Figure 21. While CC units have an increase in costs from the Base Case to the 25% DER scenario as these units replace much of the generation from coal and take on a larger baseload role.

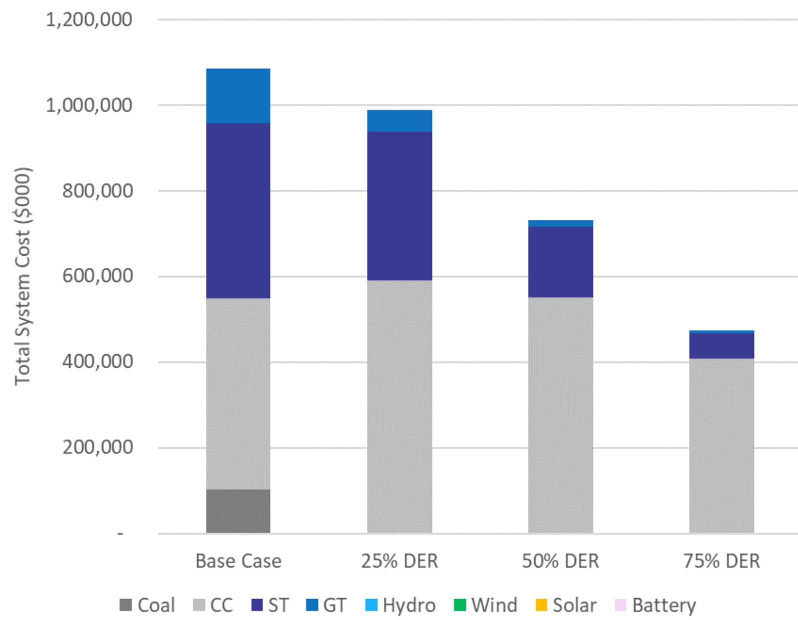

Figure 21: Total System Cost (2020 real $000) by Unit Type

5.3 Regional Flows

Another benefit of DER integration is that the resources are sited directly at the loads, reducing the total amount of energy that flows across the transmission network. This yields reliability, resiliency, and avoided transmission loss benefits. Currently Puerto Rico's generation is predominately located on the south-side of the island and is transferred via high-voltage transmission to the load centers in San Juan and Bayamón. This makes the system susceptible to outages due to transmission failures caused by weather and line outages.

The annual regional flows between the eight PREPA regions are provided in Figure 22, where positive numbers represent net exports and negative numbers represent net imports. In the Base Case both Ponce ES and Ponce OE are the only net exporters among the eight regions. However, with the retirement of AES beginning in the 25% DER case Ponce ES becomes a net importer. The overarching trend from the Base Case to the 75% DER case is that net flows decrease as each individual region becomes more self-sufficient with the increase in DERs located within that respective region. Despite individual regions becoming less reliant on neighboring regions for power the general imbalance of the southern part of the island, particularly Ponce OE, sending power to the northern regions continues, but to a much lesser extent. San Juan even becomes a small net exporter, predominately to neighboring loads in Bayamón, as the large increase in commercial solar flows back to neighboring regions.

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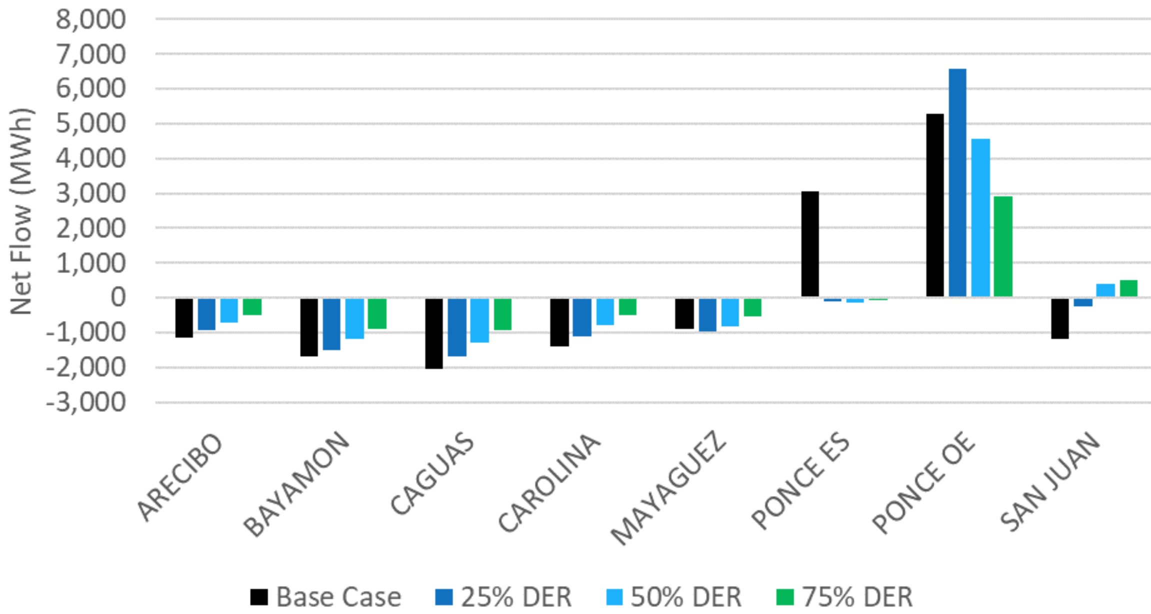

Figure 22: Annual Net Flows by Regions

The annual net flows shown in Figure 22 align with the hourly net flow duration curves highlighted for each region in Figure 23. The duration curves sort the hourly flows from each region from highest (exporting) to lowest (importing). This illustrates that most regions will see changes in the net transmission flows over the course of the year. From this chart, the following observations can be made:

- Arecibo, Bayamón, Caguas, Carolina, Mayagüez, and San Juan all see an increase in the number of hours with positive net flows out of their respective region.
- Ponce ES experiences a steep decline in net flows from the Base Case to the higher DER cases, largely due to the retirement of AES.
- Ponce OE shows a different trend, with much of the island's fossil fuel-based capacity located in Ponce OE it remains a strong exporter to other regions. Whereas once there are further retirements of fossil fuel-based generators and increased DER Ponce OE begins to follow the same trend as the other regions.
- The change in flows are most pronounced for about half of the year, which represents changes brought about by solar generation during daylight hours.

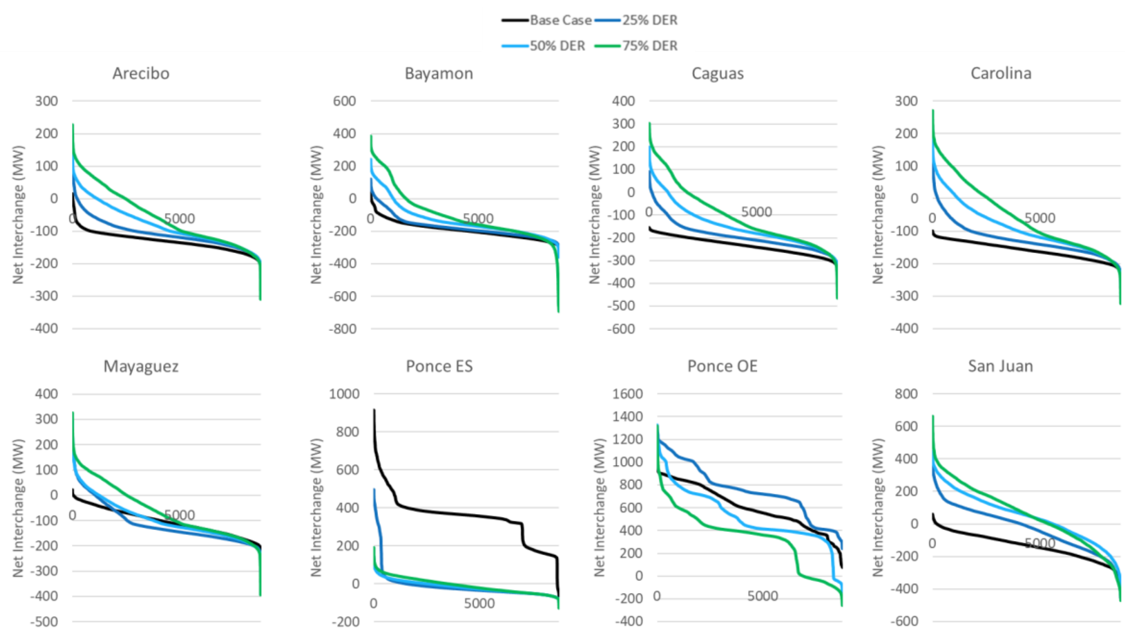

Figure 23: Duration Curves of Hourly Net Flows (MW)

5.4 Operations of Solar and Battery Storage

While the previous section focused on the total system dispatch and changes to the fossil fleet, it is also important to evaluate the utilization of the solar and storage resources. One important metric is the overall curtailment, which represents the amount of variable renewable generation that cannot be delivered to the grid due to oversupply and flexibility constraints. This can occur for both wind and solar resource and is often presented as a percentage of total available generation based on weather conditions.

With the coincident rise of battery storage the increase in solar DER curtailment is effectively mitigated, despite solar PV exceeding total load in many hours of the day. Figure 24 provides the annual curtailment of wind and solar resources, as a percentage of available energy. This figure shows that curtailment of solar resources is always quite low and is highest (on a relative basis) in the Base Case before any storage is added. This same relationship holds true for wind power that is curtailed. It is highest in the Base Case with no curtailment during the 25% and 50% DER cases but experiences a slight resurgence in the 75% DER case. Wind curtailment is higher than solar (on a relative basis) for two reasons; for one it is not paired with battery energy storage and thus is less likely to be shifted to later time periods, and second the DER is given “priority” to generate because it represents customer-sited generation. From a total renewable energy perspective, curtailment is limited to no more than 1% in all the DER scenarios.

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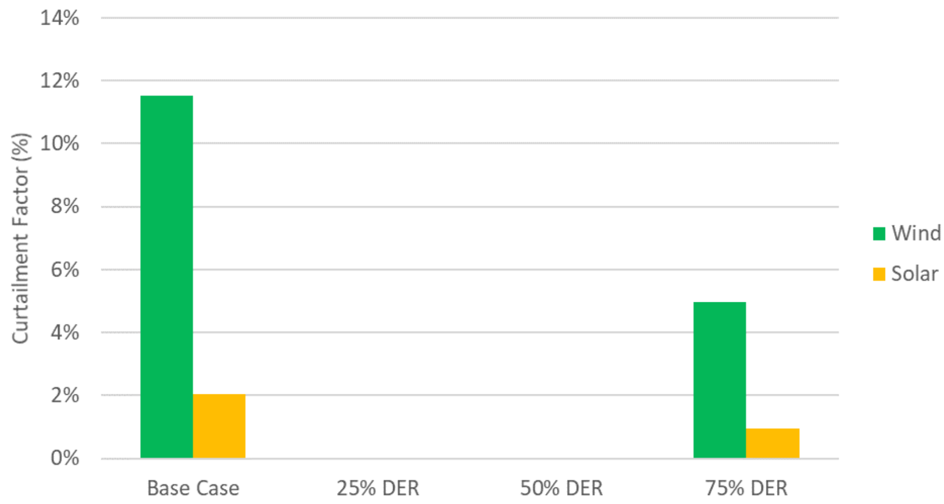

Figure 24: Curtailment Factor by Unit Type

This low level of curtailment is primarily due to the amount of battery storage that is also added to the hybrid systems. The impact of battery storage is clear when looking at Figure 25, which shows the net-generation of the battery storage fleet for the average day across the year. Positive numbers represent battery discharge and increased generation on the grid, and negative numbers represent charging (or increase in load). On the x-axis there are 24 hours starting with 0 and going to 23.

The chart shows the batteries on average discharge during evening peak load hours after sunset (hours 17 to 23) and early morning load hours before sunrise (0 to 6). Charging occurs predominately in the middle of the day, in line with the solar generation profile. This is also in line with the behavior shown in Figure 17. The net-generation changes highlight why we see minimal curtailment of solar while adding storage. As DER increases from 25% to 75%, the amount of generation charging the batteries in the middle of the day increases markedly, from just above 500 MW in the 25% DER case to more than 1,500 MW in the 75% DER case.

Figure 25: Average Battery Net Generation (left) and State of Charge (right) by Hour of Day

While looking at net-generation data is helpful it is also worthwhile to look at total energy, or MWh, of storage during an average day, as shown in Figure 26. This represents the amount of energy, on average, that is stored in the battery for use at a later time. The same profile is visible with the batteries charging during the day (increasing the battery storage to higher levels) and discharging in the morning and evening hours (depleting the battery storage to lower levels). From the 25% DER case to the 75% DER case there is more than twice as much energy stored in batteries going into the evening peak hours. Despite the 75% DER case starting from this higher level the batteries on average draw down to a very similar point across the three cases. This is due to the fact that batteries are also able to provide valuable grid services and some energy is stored during overnight periods so that the batteries can provide reserves in case they are needed unexpectedly.

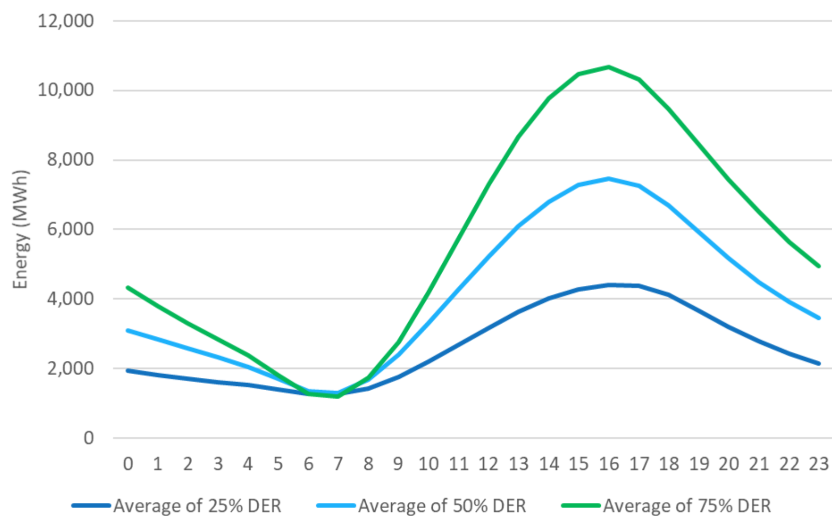

Figure 26: BESS Energy for the Average Day per Year

Another useful measure for battery utilization is the number of cycles that are accrued over the course of the year. It measures the total energy throughput of the battery, where one full charge and one full discharge is one cycle. Partial cycles can also be accrued, where two 50% charge and discharge events equal to one cycle. The total number of cycles provides an indication of how much the storage is utilized and is also important to measure expected degradation. There are multiple reasons why batteries may not be cycled fully each day:

- The solar resource is low and does not provide enough energy to charge the batteries and grid charging may not be economic nor necessary,
- The battery is not fully discharged because it is being utilized to provide contingency reserves,

The round-trip efficiency losses of charging the battery storage may not make it economic to charge all of solar energy when it can be delivered to the grid during the time of generation. This is illustrated in Figure 27 where the 25% DER case is on average seeing its battery resources cycle roughly 270 times per year while the 75% DER case has about 325 cycles per year. Note that this does not take into account potential additional behind-the-meter use cases of storage, which may change battery utilization due to an individual customer's use case. For example, any individual battery system may have output that is considerably different than the system-wide average, but on net the system would see battery utilization that generators during evening peak load hours and charges during the middle of the day.

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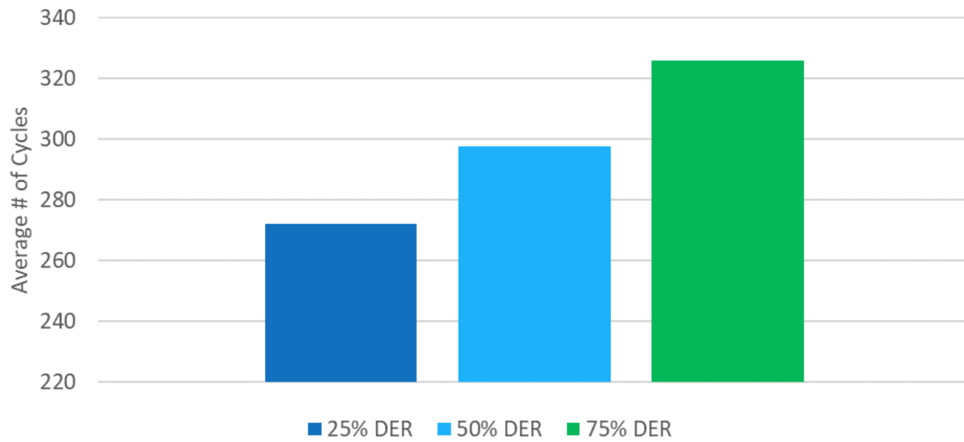

Figure 27: Annual Number of Battery Cycles by Scenario

5.5 Instantaneous Generation from Inverter-Based Resources

While the previous section covers the annual generation and utilization of DERs, it is critical to also evaluate the instantaneous operation of these resources across the entire year. This is because both solar and batteries (as well as wind) resources are inverter-based resources (IBR). IBR rely on a suite of power electronics, including the inverter, that help these units properly regulate their performance to meet grid conditions at any given time. As these resources take on a larger role in the grid there could be operational challenges, which are discussed in detail in Section 6. It is important to note that because solar and wind resources are variable they may, at times, reach very high levels of penetration (as a percentage of the grid's total resource mix) even if their annual generation levels are relatively modest.

Figure 28 shows that as more IBR is added with each scenario all hours have a greater total generation and percentage of IBR providing generation. Of particular note is that in the 50% DER and 75% DER case there are hours with 100% of generation coming from IBR, even after using storage to shift much of the surplus generation. Since inverter technologies needed to manage these conditions are still under development, reliability will need to be addressed through operational changes to mitigate challenges as well as consideration for synchronous condensers in higher penetration cases. In the 50% DER case only 4 hours across the entire year have all their energy coming from IBR – suggesting that this challenge could be mitigated with operational changes. However, in the 75% DER case nearly 1,250 hours have 100% of generation coming from IBR, this is just over 14% of all hours of the year. One could expect inverter technology advancing in the upcoming years to mitigate these situations, but if not the introduction of synchronous condensers could provide needed stability.

It is also helpful to see this data from an absolute MW perspective in the left plot. IBR generation often exceeds peak load (2,120 MW) in both the 50% DER and 75% DER cases due to the fact that much of the generation goes directly into the battery storage systems.

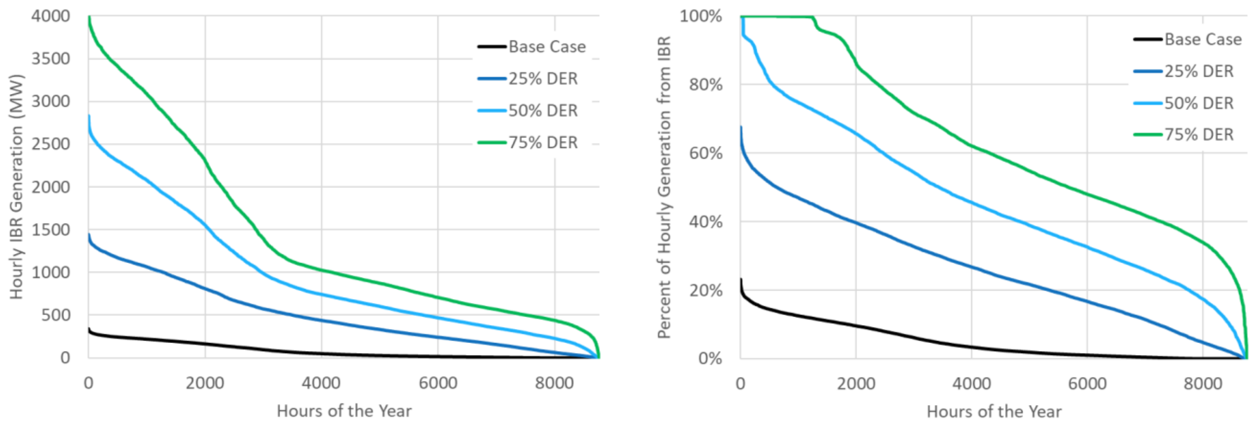

Figure 28: Duration Curve of IBR Generation (left) and Percent of Total Generation (right)

As mentioned above, the peak load is only 2,120 MW so it is clear there are hours when solar is generating much more than load. Although this surplus energy could be curtailed, Figure 24 shows this rarely happens. Instead this surplus is being used to charge batteries. Figure 29 highlights how even in the 25% DER case there are hours where solar is approaching 100% of load. By the time the system achieves 50% DER and 75% DER the system is experiencing times when solar is generating more than 200% of system load. This chart highlights the large role battery storage has on the system and the sheer scale of the resource mixes evaluated in this study.

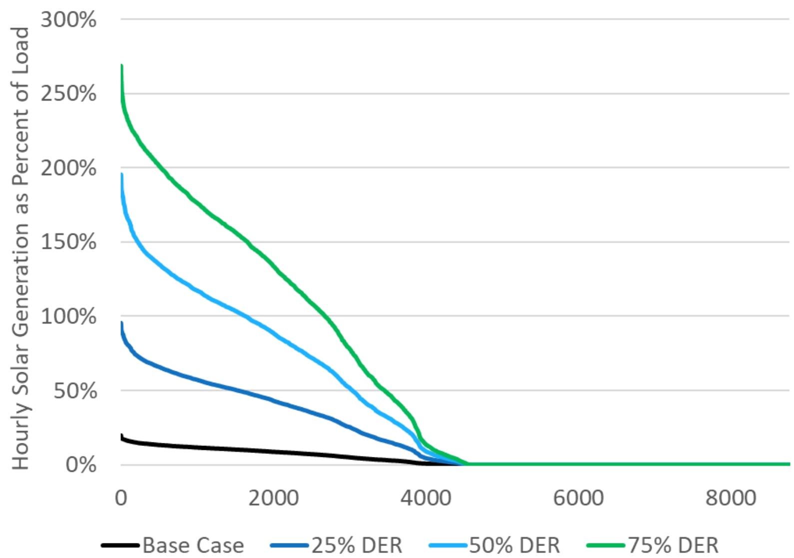

Figure 29: Duration Curve of Hourly Solar Generation as Percent of Load

Another way to view the impact of increased IBR on the system is to look at the number of fossil fuel-based units online across each hour of the year. This directly relates to the amount of synchronous inertia online (discussed more in Section 6). A system is generally more stable with a larger number of units online as there is more inertia and ability to maneuver the system to compensate for either a loss of any given generator or other unexpected changes to grid operations. In Figure 30 the Base Case has anywhere from 20 to 6 units online at any given hour, whereas the cases with an increased amount of

DER rarely have more than 8 units online. Both the 50% DER and 75% DER cases almost always have less than 6 units online, the minimum number of units online during any hour of the Base Case. The hours during which there are fewer fossil fuel units online correspond to periods of higher solar generation in the DER scenarios. The units that stay online during these periods are those providing more baseload like power, even if they are often forced to cycle themselves, which in the DER scenarios are the combined cycle units. This behavior is illustrated in the dispatch diagrams included in Figure 17 and Figure 18. The number of fossil units online does not represent a problem in and of itself, but it is a key metric to watch. Especially as the system spends an increasing amount of time operating in the range of 2 to 0 units as experienced in the 75% DER case.

And as above, the percentage of generation from fossil fuel-based units is a helpful way to see the impact that increased DER penetration has on the system. In Figure 31, the Base Case is almost entirely reliant on fossil fuel-based generation while there is a marked decrease on its reliance as the DER buildout increases. This is also apparent when looking at the absolute amount of generation from fossil fuel-based units, as shown in Figure 32. Although the reliance on fossil fuel-based units decreases with the integration of more DER capacity, they are still needed during more than a third of the year to cover more than 50% of load in even the 75% DER scenario. These are hours where there is either low solar output and/or high load.

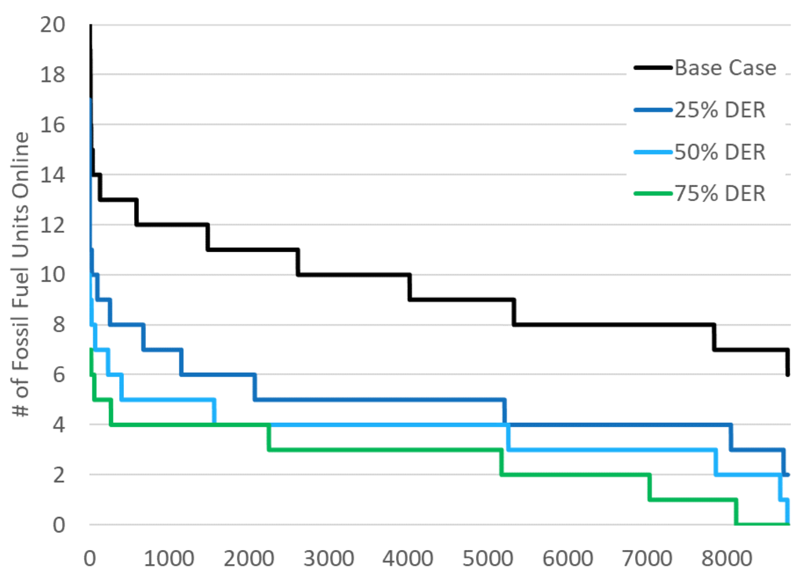

Figure 30: Duration Curve of Number of Fossil Fuel Units Online

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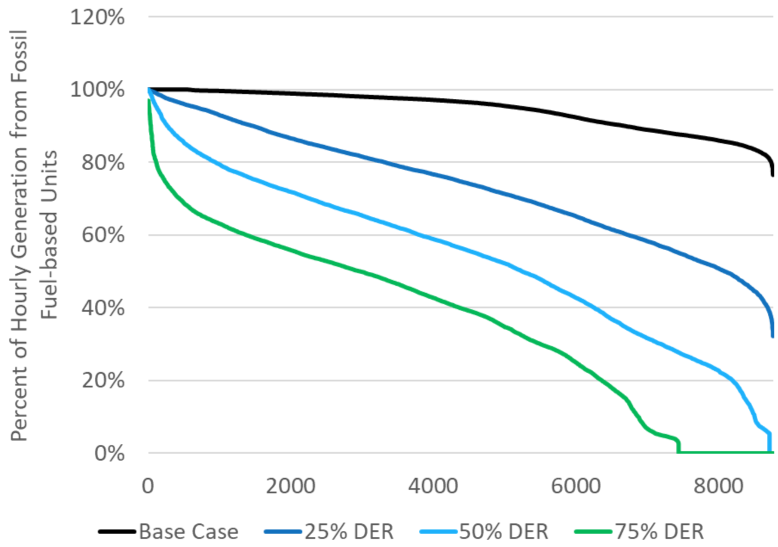

Figure 31: Duration Curve of Percent of Hourly Generation from Fossil Fuel-based Units

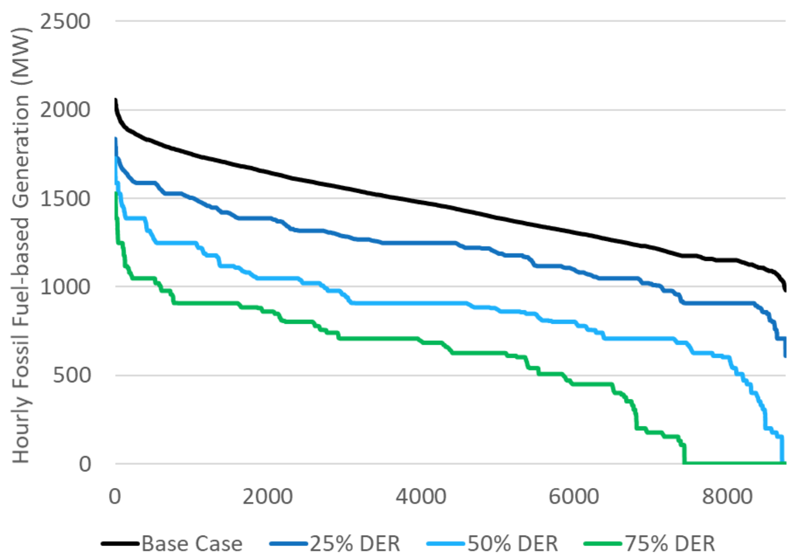

Figure 32: Duration Curve of Hourly Generation from Fossil Fuel-based Units

6 Grid Stability Analysis and Results

6.1 Introduction

All electric power grids must be analyzed to ensure stable operation under a large variety of operating conditions, environments, and grid disturbance events. This is true regardless of the level of renewables on the grid. However, grids with very high levels of renewables face more acute technical challenges because of the high-levels of inverter-based resources (IBR) like PV and battery systems and the displacement of conventional power plants with synchronous machine technology. However, these new resources also offer new benefits for supporting the grid in ways that were not previously available with a conventional power plant technology. These benefits are primarily due to the flexibility and speed of the inverters that form the interface between the resource (solar or battery) and the grid. The flexibility is because of a programmable response of inverters to different grid conditions and grid events. The speed refers to the faster rate at which IBRs are capable of responding to changing grid conditions. While a fast or faster response is not always desirable, it can be useful in certain circumstances. These advantages, coupled with an energy reservoir as in the case of battery storage, makes for a powerful combination (as shown through simulations of the grid in this section) that can help support a future grid with a dramatically different generation mix than the one that exists today.

6.2 Technical Challenges Assessed

To assess the stability of the grid under the proposed high-renewable scenarios, the following aspects of grid dynamic stability have been evaluated by simulating the response of the grid to disruptive events or grid disturbances. When studying a grid at such high levels of inverter-based generation, it is important to acknowledge the limitations of the simulation tools and to differentiate between challenges posed by the simulation tools and challenges posed by the operation of the physical grid itself. An overview of these challenges is presented in Table 10.

Table 10: Overview and Differentiation of Challenges for High-Renewable Grids

Grid Stability Challenges (Physical)	Analysis Challenges (Simulation Model)
Frequency Stability (i.e. low inertia)	Numerical solution divergence
Fault Recovery (i.e. ride-through)	Insufficient inverter detail represented
Inverter control stability	Insufficient grid detail represented

Grid Stability Challenges

The frequency stability challenge refers to the ability of a grid to maintain a frequency near its nominal value, in this case, 60Hz. Large deviations in system frequency from the nominal value (greater than about 1Hz) trigger emergency protection schemes like load-shedding, while very large deviations in frequency (greater than about 2Hz) push the grid close to its limit and often result in a grid-wide collapse or blackout.

Grid frequency is maintained close to 60Hz by maintaining a balance between generation and load. If generation exceeds load (for instance, due to a sudden loss of load), then grid frequency rises and generation must be reduced to bring frequency back to nominal. If generation drops below load (for instance, due to a sudden loss of generation), then grid frequency decreases and additional power must be injected to the grid, or load must be reduced or shed, in order to restore grid frequency.

These corrective actions must be taken quickly, within a few seconds or less, in order to be effective. This is because grid frequency will continue to deviate further and further from its nominal value until the power balance is restored. Providing the corrective power too late will result in a grid blackout if the grid frequency has already reached a point beyond which there is no return due to the excessive disconnection of other generators for self-protection reasons. Furthermore, the window of time in order to restore power balance after the initial loss of generation event is dependent primarily on the size of the initial power imbalance (MW of power generation being produced by the generator that suddenly disconnects or “trips”) and the number and size of remaining synchronous machines (conventional generating units) online. Each synchronous machine online provides an “inertia” to the grid that opposes sudden changes in grid frequency, just as a car driving down the road continues to coast even if accelerator pedal is suddenly not depressed. More synchronous machines and physically larger synchronous machines contribute higher amounts of inertia, which helps provide a longer window of time to correct the power imbalance. However, as more renewable generation comes online and fewer synchronous machines are needed, the inertia of the grid decreases and the window of time to respond to a loss of generation, particularly a large loss of generation, shrinks.

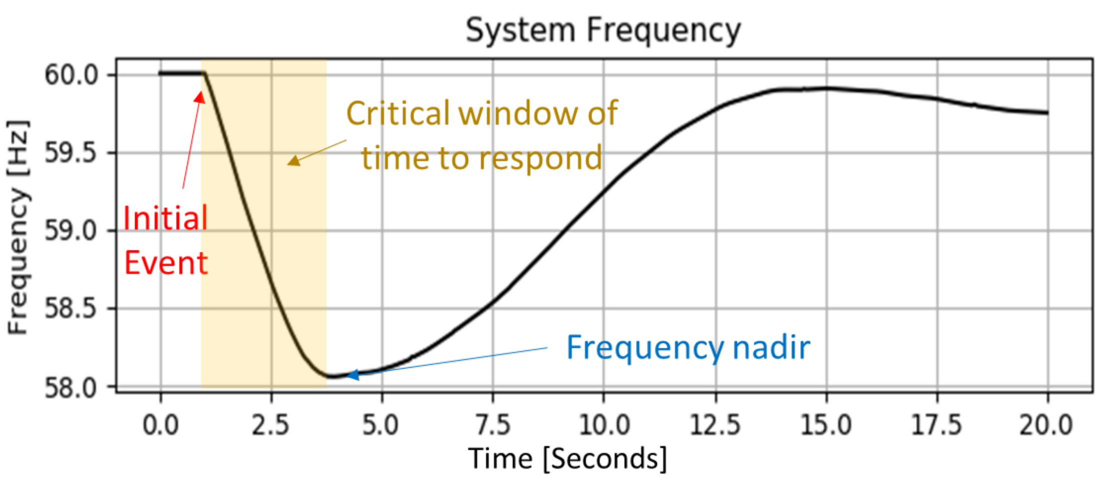

Figure 33 : Illustration of a Loss of Generation Event on Grid Frequency

In this analysis, the focus is on a loss-of-generation event because it is generally more difficult to quickly increase generation power than it is to quickly reduce power from existing generation, as would be needed for correct a loss of load event. In this analysis, it is assumed that the auxiliary load of a generating unit remains online even if the generator itself is lost, which is typical as the pumps, fans, and control systems of a power plant are designed to remain connected to the grid even if the generator disconnects.

Another group of challenges is termed “Fault Recovery,” which is the ability of the grid to recovery from a fault event, or a short-circuit on the grid. Grid faults may be causes by obstructions like trees falling on transmission lines, lightning strikes of lines or towers, the collapse of transmission towers, etc. When such a fault occurs, the grid is designed to quickly remove the faulted transmission line from service, thereby “clearing” the fault from the grid, as shown in Figure 1. The intention is that the grid continues to operate without the line in-service until a crew can be dispatched to repair the line.

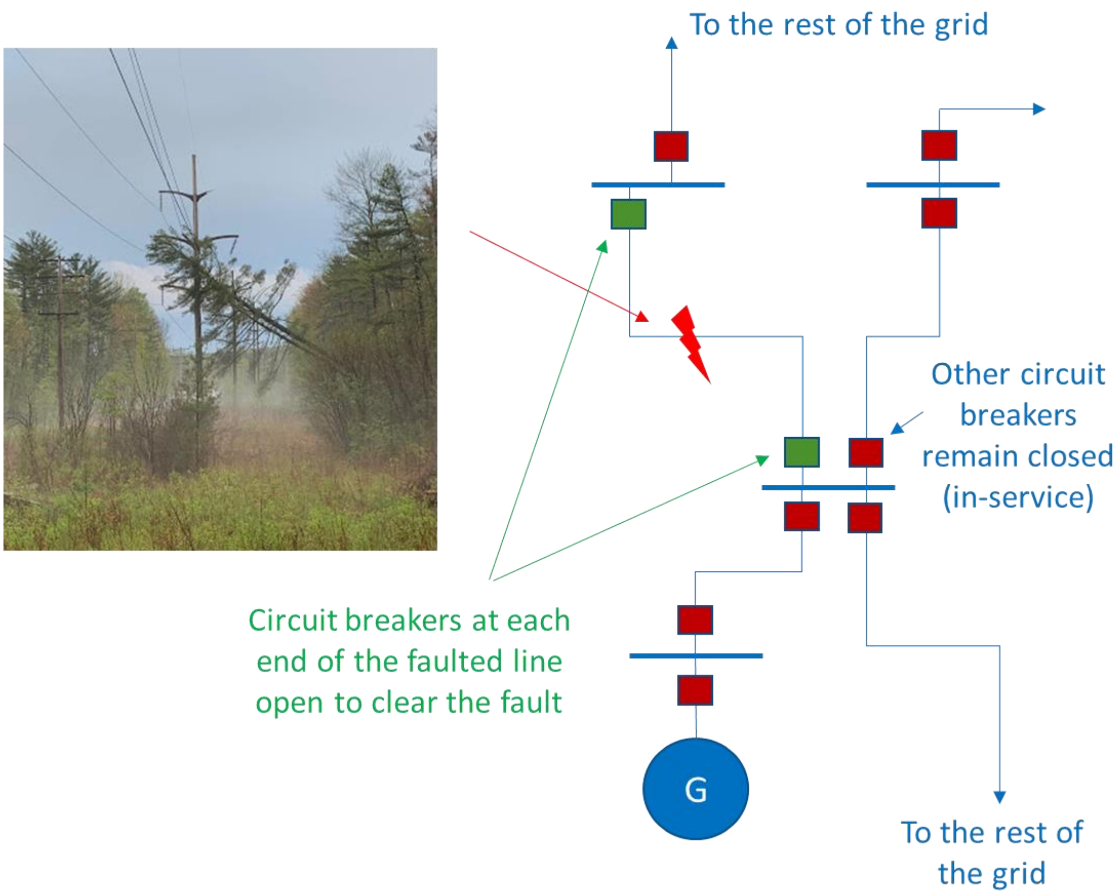

Figure 34: Illustration of a Grid Fault Event

In the brief period of time between the onset of the obstruction contacting the transmission line and the time when the circuit breakers on either end of the line open, the voltage on the line is severe depressed from a normal voltage of near 1.0 per-unit (pu) to near 0.0 pu, as shown in Figure 35.

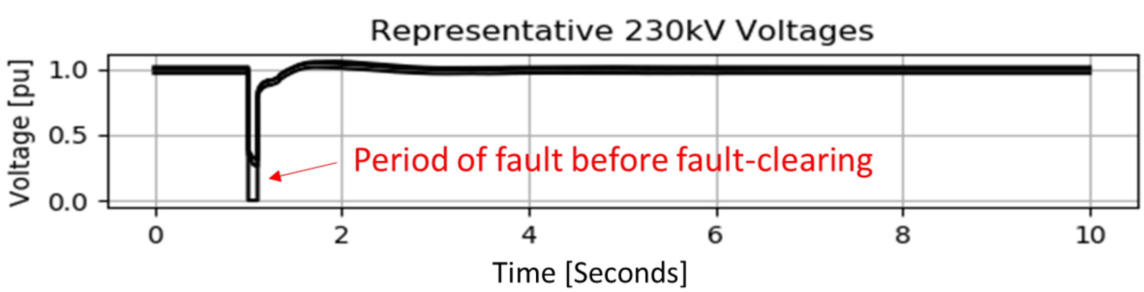

Figure 35: Illustration of a Fault Event Simulation

During a fault event where voltages are severely depressed, the ability of the transmission system to transmit power is very limited, such that generators cannot deliver the power they are generating and load suddenly stop receiving power. The impact this has on the grid is highly dependent on the type of generation (synchronous or inverter-based), the configuration of the generator's controls, the types of loads (i.e. electric lighting loads behave very differently from electric motor loads in air-conditioners), and the depth of voltage depression as seen by each generator and load. Furthermore, grid response to a fault depends on the duration of the fault (the time before the fault is cleared) and the number of phases involved in the fault. For this analysis, faults are assumed to be 100msec in duration, involving all three phases, and have zero fault impedances; assumptions which are aligned with PREPA's transmission planning practices. It is important to note that three-phase faults are the most severe type of fault and also the rarest type of fault in reality. Therefore, these assumptions are considered conservative.

The final group of challenges considered are inverter control stability challenges. These refer generally to the behavior of an inverter to respond in a stable manner to grid events like the loss-of-generation events and fault events described. Examples of unstable behavior includes oscillatory behavior to a failure to ride-through and recover from the disturbance without causing voltages or currents that are damaging to the inverter or other equipment. While time oscillatory behavior may be acceptable for brief periods of time (well-damped behavior), sustained or growing oscillations are not acceptable. Such oscillations may be the result of improper tuning of inverter controls for the grid conditions, or they may be the result of interactions among various inverters and/or synchronous machines on the system. These unstable behaviors are often initiated by a fault or loss-of-generation event, and therefore, the simulated disturbances are also testing for inverter control stability.

This analysis is intended to be an initial foray into analyzing ambitious and challenging set of proposed scenarios that shows a viable path forward by identifying challenges, potential mitigations, and where more attention is warranted. It is acknowledged that this analysis does not cover every aspect of grid stability. For instance, transmission protection systems are a critical part of operating a reliable grid as they are responsible for quickly identifying faults on the transmission system and clearing them with minimal impact. The industry has recognized that high levels of IBR present new challenges in the correct identification and discrimination of grid faults by some transmission protection schemes. While this analysis considers basic transmission system protection (voltage and frequency deviations), it does not consider the detailed inner workings of actual transmission line protection relays on the grid, which should be considered at some point along the journey to realizing the proposed scenarios.

Analysis Challenges

The simulation tools and models used in this analysis are widely used across the industry for transmission studies and stability analysis, and these models have been found to work well for grid with low to moderate levels of inverter-based equipment relatively to the levels of synchronous machine-based equipment on the grid. As the collective rating of IBRs approaches the collective rating of synchronous machines on the grid model, or even in a region of the grid model, several problems in the analytical domain can arise:

- The simulation tools struggle to find a numerical solution or converge. While a failure to converge can be indicative of an infeasible operating condition in reality, this is not necessarily the case. Other tools or methods must be applied to confirm that such a conclusion is valid. To mitigate this challenge, the parameters of the solution engine have been adjusted to improve the convergence characteristics of the model.
- The simplifying approximations made during inverter model development of actual inverter equipment and controls may no longer be valid in an inverter-dominant model. For instance, the

simplification or omission of special control functions and features may become more pronounced such that the model is no longer representative of the actual equipment. In general, the industry intends to develop models that are conservative such that inaccuracies due to simplifications made to the model cause the model to behave worse in simulation than in the field. Therefore, poor model performance is not always reflective of poor equipment performance. To mitigate this, the industry's best-in-class models have been applied and tuned to achieve good performance.

- The simulation tool, being a fundamental-frequency positive-sequence solution engine, is limited in its ability to capture all of the physical reality of the real world. Very fast transient events, transient responses, phase imbalances, harmonics, and non-sinusoidal phenomena are not captured in such a model. Other tools like electromagnetic transient (EMT) analysis tools have been developed to capture more completely these details as well as to facilitate full representation of inverter hardware and controls. However, these models require an order-of-magnitude more detail and complexity, which makes them more appropriate for subsequent detailed study work and not for initial study work.

It can be difficult to differentiate between a true grid stability problem and a modeling and analytical tool problem when analyzing dynamic simulation results with very high levels of inverter-based generation. In some cases, the simulation model may fail and appear to result in a loss of the grid when the grid operation would have been feasible in reality, resulting in a false-negative. It may also be possible to have false-positive results where the model predicts stable operation for what would be unstable in reality, but these cases are rare as the models are generally designed to be conservative and avoid producing false-positive results. Through experience and probing of the simulation tools, an engineering judgment is made on the results of the simulations presented in this analysis to determine at what point the PSSE models are to be believes and at what point other tools and models are needed for drawing conclusions.

6.3 Case Selection

The grid stability simulations capture the dynamic response of the grid over the course of 10 to 20 seconds following a grid event like a loss of generation or a fault event. Because it is impractical to simulate the dynamic response of the grid over the course of an entire year, as was evaluated in the production cost analysis, a selection of "snapshots" in time from each of the scenarios was selected for simulation of dynamic grid stability. The selection of these "snapshots" is very important as they must be chosen to be representative of a range of grid operations and not "cherry-picked" as worst-case or best-case operations, which would skew the conclusions drawn from the results.

To guide selection of representative snapshots for dynamic simulation, two important factors are defined and quantified for every hour of the year for each of the four scenarios. These are:

- **System Inertia**, H_{sys} [MW-s]: System inertia is a measure of the total inertia contribution from all online synchronous machines. Lower values of system inertia are associated with fewer synchronous machines online and result in the grid frequency moving faster after a disturbance, which makes a successful recovery of the grid more difficult.

$$H_{sys} = \sum_{0}^{i} MVA_i H_i$$

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Where:
i is the i^{th} synchronous machine online in the grid, and
H_i is the inertia of the individual synchronous machine in per-unit on its MVA base

- **Synchronous Ratio** [-]: The synchronous ratio is defined as the ratio of the total rating (MVA) of synchronous machines online to the net generation (MW) of IBR at the time. Lower values of synchronous ratio indicate that the grid is becoming more inverter-dominant, which makes fault recovery and inverter control stability more difficult and also challenges the numerical methods used in the simulation tools.

$$Sync\ Ratio = \frac{\sum MVA_{sync\ machines\ online}}{\sum MW_{IBR\ generation,net}}$$

To see how these two important factors behave for the scenarios evaluated, a time-series of the first week of grid operations is shown in Figure 36. The top two windows show the total thermal generation and the total IBR generation in MW, respectively. The bottom two windows show the system inertia (H) and the synchronous ratio, respectively. In examining the inertia time-series, its shape is stepped as synchronous machines are brought online or taken offline. In the current scenario (black), the reduced inertia period tends to occur during overnight (early morning) periods where load is reduced and there is less need for power plants to be online, as would be expected. Examining the synchronous ratio time-series, the current scenario (black) shows generally high values (off the chart) indicating that there are far more synchronous machines online than MW production of IBR, as would be expected. During mid-day periods when there is more solar generation, the synchronous ratio dips into the 10-15 range, as would be expected.

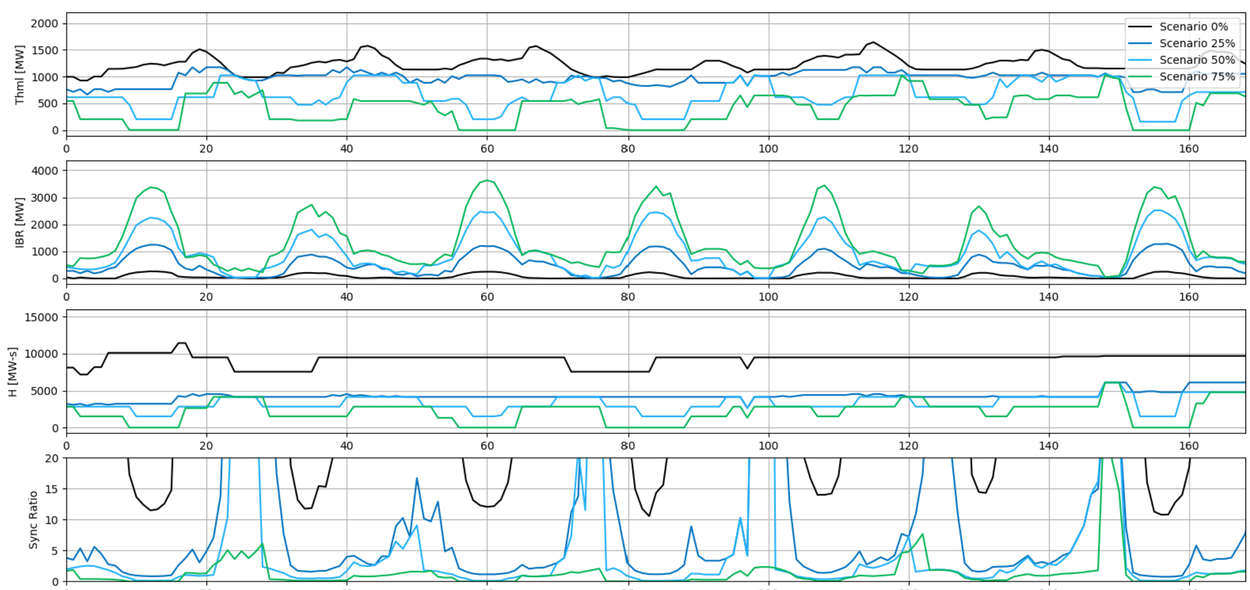

Figure 36: One-Week Time-Series of Grid Operations and Key Stability Factors

To examine the system inertia and synchronous ratio over an entire year of operation, the values of the time-series are sorted to form a duration curve for each factor and each scenario, which is plotted in

Figure 37. As expected, the scenarios with higher levels of renewables appear as lower values on the chart, indicating that those scenarios contain more hours of operation that are challenging to grid stability. Also note the extremely low values where system inertia and synchronous ratio both drop to zero, indicating that the production cost simulation anticipates time of an all-inverter-based grid. In the 50% scenario, this is expected for a small handful of hours in a year, which could be managed with relatively small operational changes to maintain a minimum number of synchronous machines online. In the 75% scenario, a fully inverter-based grid would be expected for over 1000 hours in a year, which would require advanced inverter technology like grid-forming inverters and/or the use of existing technologies like synchronous condensers, both of which are discussed in more detail in Section 6.6 .

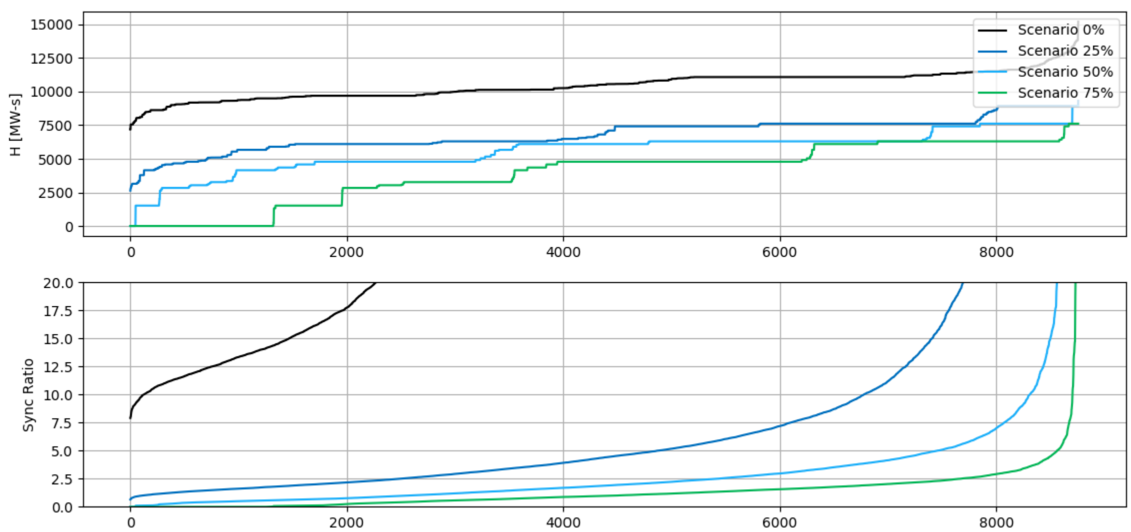

Figure 37: Duration Curve of Key Grid Stability Factors

Next, the specific hours or snapshots of grid operation are selected for dynamic simulation, which are shown on the duration curves as red dots in Figure 38. The selection criteria included that each scenario be evaluated, but with a focus on higher renewable scenarios. It is important that a range of system inertia values be evaluated (different “stair steps” on the plots) as well as to capture a range of synchronous ratios, with a focus on lower values where IBR generation is higher.

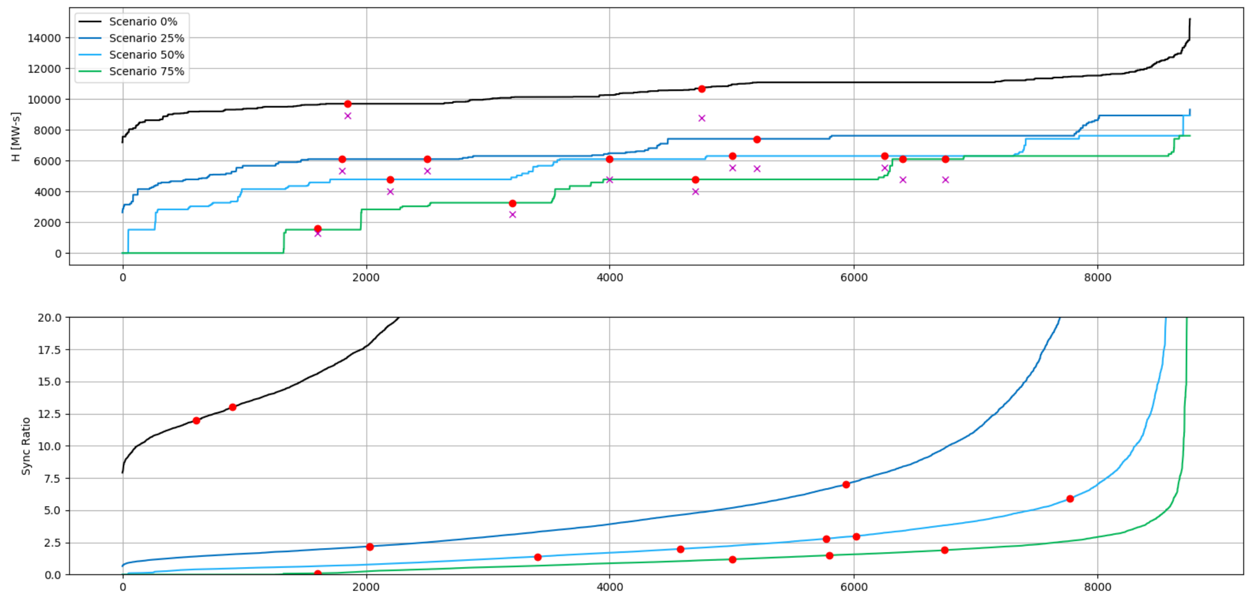

Figure 38: Case Selection for Dynamic Stability Simulations

Furthermore, it is important to consider for the loss-of-generation events, conditions where there is high levels of generation from the largest unit because the loss of a very large generator is more devastating to the grid than the loss of a small or minimally-dispatched generator, even if the system inertia in that case was slightly lower. Table 11 shows the highest dispatch of the largest single generators on the system for each scenario; the red text highlights the value and unit with a maximum dispatch for the scenario.

The cases that include the maximum dispatch shown in red have been included in the analysis for loss-of-generation events as they challenge grid stability in ways not necessarily captured by the system inertia and synchronous ratio factors alone. A magenta "X" on the system inertia plot shown in Figure 38 is used to mark the system inertia level remaining on the grid after a loss of the largest unit. To provide more context for these, the last row of Table 11 shows the percentage of hours over a year of operations where the unit with maximum generation is within 90% of its annual maximum dispatch.

Table 11: Highest Single Unit Dispatch Generation Values for Each Scenario

Generator Unit	Pmax (MW)	Base Case	25% DER Peak MW	50% DER Peak MW	75% DER Peak MW
AES (1 or 2)	227	155	0	0	0
Eco Electrica ST	181	178	181	181	181
Costa Sur ST (5 or 6)	410	360	410	**410**	**410**
Aguirre ST (1 or 2)	450	**367**	**450**	0	0
Palo Seco ST (3 or 4)	216	156	0	0	0
% of hours red unit is within 90% of Peak MW		0.3%	1.2%	13%	3.8%

It is noted that the loss of the entire Eco Electrica combined-cycle power plant (507MW total) is not considered in the loss-of-generation scenarios, but only loss of the largest individual unit of Eco Electrica

– the steam-turbine generator (STG). It is acknowledged that Eco Electrica is connected to the remainder of the grid by a single 230kV transmission line. While this line is short and its right-of-way well-managed, a loss of this line would result in a loss of the entire Eco Electrica plant, and potentially a system-wide blackout.

For each of the selected cases evaluated, faults were analyzed on 6 different transmission lines across the system, which is shown in Table 12 and Figure 39. As previous discussed, all faults are analyzed as three-phase, zero-impedance, six-cycle fault-and-clear events. The double-circuit transmission line from Aguirre to Aguas Buenas is modeled as both circuits being simultaneously faulted and cleared.

Table 12 : Summary of Transmission Fault Locations Evaluated

From Bus	To Bus	Circuit Voltage	Number of Circuits
Aguirre	Aguas Buenas	230	2
Costa Sur	Manati	230	1
Costa Sur	Maya TC	230	1
Costa Sur	Dbocas Fase	230	1
Cayey	Caguas	115	1
Guanica	San German	115	1

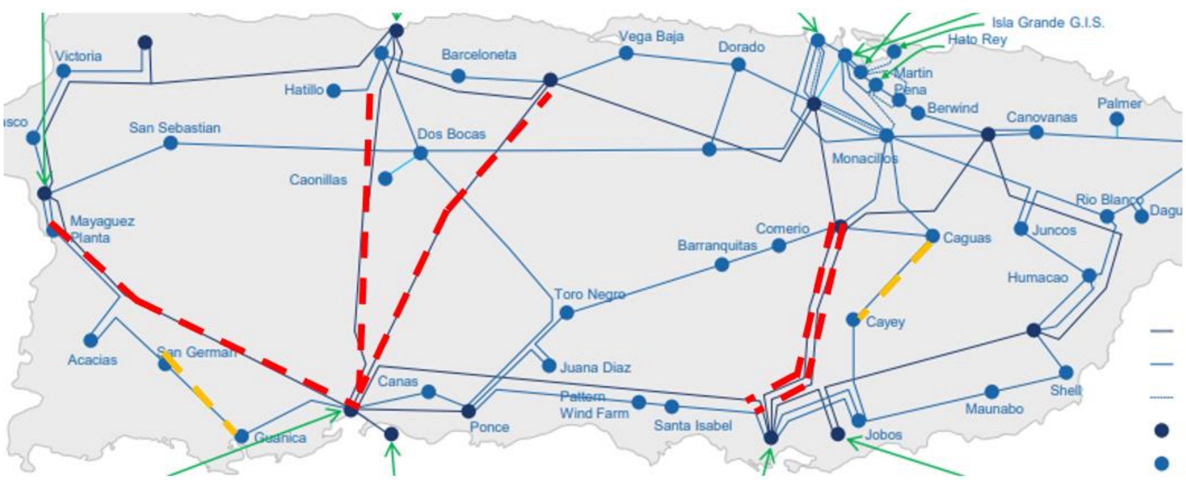

Figure 39: Transmission Fault Locations Evaluated

6.4 Loss of Generation Results

There are a few typical indicators used to evaluate grid performance for a loss-of-generation event, including frequency nadir and the amount of under-frequency load-shedding (UFLS). In addition, other indicators of performance include the rate-of-change-of-frequency (RoCoF), damping, system voltage excursions, and the quality of the recovery of the system. It is important to note that the Puerto Rican grid uses a sophisticated UFLS scheme that does not simply monitor grid frequency but also monitors the dynamics of grid frequency when decided whether or not to shed load. Such a system intends to minimize load shedding. In this case, the frequency nadir is a less meaningful metric because both severe and moderate grid events result in approximately the same frequency nadir. Therefore, the amount of UFLS is used instead as a primary indicator of system stress and margin from blackout.

First, the simulated response of the grid is shown in Figure 40 for a case in the current scenario with a loss of Aguirre STG2, where there is ample system inertia and a generally good recovery to the loss of generation. System frequency immediately begins to drop at 1.0 second when the generator is tripped. Three seconds later, the grid frequency has reached its lowest point and returns to a new steady-state point slightly below the nominal frequency, as would be expected until grid operator actions return the frequency to nominal. System voltages, of which a few 230kV buses are shown in the second window, indicate that voltage is well-controlled and after an initial loss of voltage support, voltages quickly recover, albeit with some relatively small oscillations due to the interaction of the remaining synchronous machines on the system. Figure 41 shows the collective response of the thermal generation fleet and the DER, which consists only of distributed PV. Thermal power generation decreases first due to the loss of the Aguirre unit, and then remain low due to the combination of load-shedding and a lack of governor response from the remaining thermal fleet. The DER power also drops in two large chunks, first at 3.5 seconds and again just after 7.5 seconds. This occurs for the portion of DER that is behind the UFLS scheme, such that as some load is shed to help the grid recover, some portion of the DER is shed. While not desirable, this is an expected result for most UFLS schemes operating on grids with significant levels of DER. A total of 255 MW is shed of a starting 1840 MW of total load.

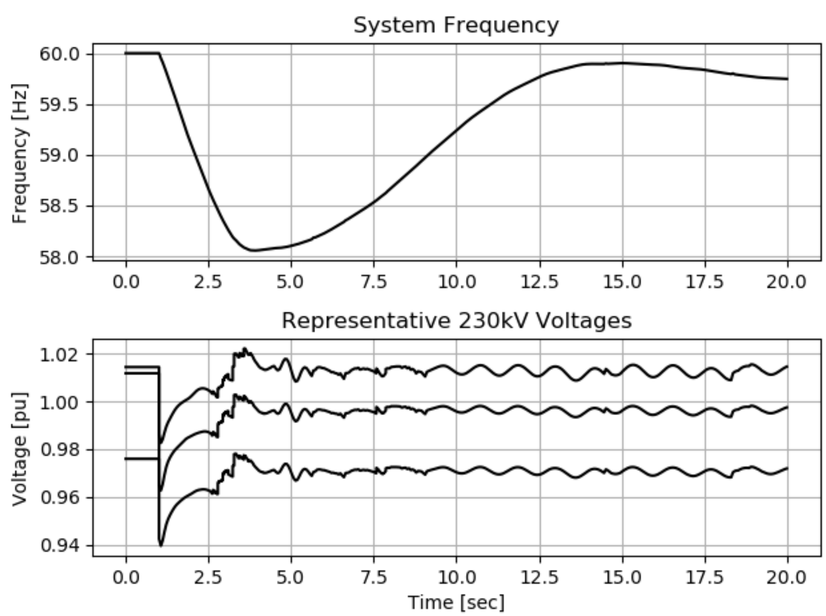

Figure 40: System-Level Response to a Loss-of-Generation Event, Current Scenario

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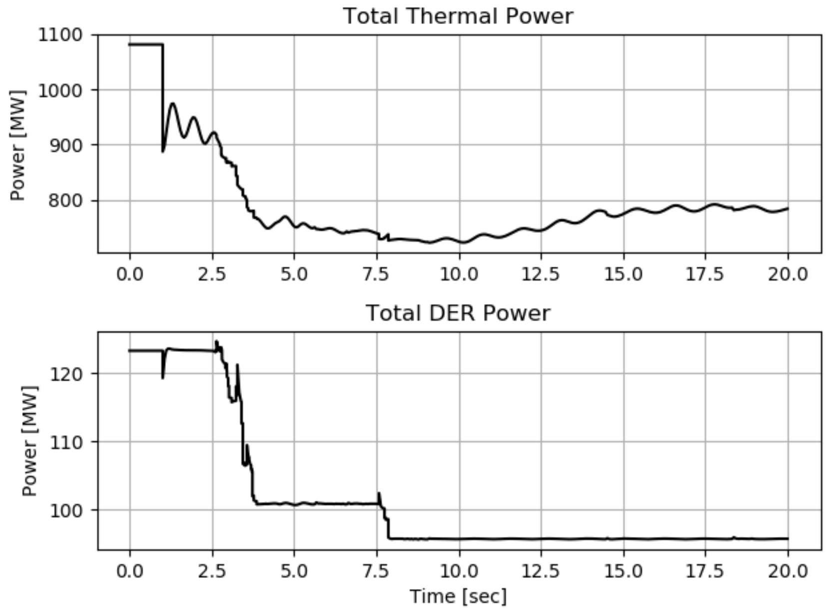

Figure 41: Generation Response to a Loss-of-Generation Event, Current Scenario

Looking at the 50% scenario in Figure 42, a snapshot is evaluated for stability that considers the loss of the Eco Electrica STG at a time when there is 200MW of DER net generation online. Figure 42 shows the response of the grid for 3 different variations. First, in the dotted traces, the generator is tripped and frequency declines as we saw in the previous graphs. The UFLS is activated, shedding load as well as over 100MW of DER that is integrated with the load. However, system frequency continues to decline, ultimately leading to a system-wide blackout because there is insufficient power injection from other resources to restore the grid to a stable equilibrium.

To mitigate this, fast-frequency response (FFR) functions are applied to the DER. The dashed trace of Figure 42 shows the response of the grid assuming that the DER has 50MW of FFR available and appropriately tuned to be deployed in 1 second. The UFLS is still activated (255MW) and 100MW of DER is disconnected from the grid by the UFLS. However, about 100MW of DER remains connected to help the grid survive, albeit with little margin. Grid frequency in the dashed trace stabilizes, but at a very low value near 58Hz. In the third variation, it is assumed that 150MW of FFR is available within the DER to be deployed over the course of 2 to 3 seconds. This fast and substantial injection of active power from DER is sufficient to stop grid frequency from falling past 59 Hz, where the grid stabilizes until subsequent grid operator actions can be taken to restore the grid frequency to 60Hz. Furthermore, no load is shed in this event. This demonstrated the power of properly configured FFR in not only saving the system from a blackout condition, but also potentially avoid load-shedding completely.

When the UFLS operates during an emergency event on the grid, one or more pieces of the distribution system are suddenly disconnected from the transmission system, typically at a 38kV substation. Each piece of the now-disconnected distribution system forms a separate and much smaller “islanded” grid. These small, islanded distribution grids would likely be comprised of different levels of DER (both solar and BESS) and load (residences and commercial/industrial centers without DER). The viability of an islanded distribution system to sustain itself and continue serving load as a microgrid or minigrid is complex and requires detailed study and specific design decisions that are beyond the scope of this analysis.

Most DER inverters are configured with "anti-islanding" detection logic that is designed to quickly detect a disconnection from the larger grid and shut down the DER, preventing an island from forming. This behavior has been historically desired for several reasons including safety of personnel and equipment, but this is changing. Even if the anti-islanding logic was disabled and even if there was sufficient battery energy and inverter power capabilities from all DER to cover the demand, today's inverters are not capable of sustaining a small, all-inverter grid, nor is the distribution system (specifically its voltage regulation and protection systems) designed to operate in this manner. In order to enable islanded microgrid operation, specific design and analysis is required for both the DER and the distribution system.

However, it is possible and relatively simpler to achieve a resiliency benefit from DER at the individual building. In the event of a loss of grid service, a building equipped with appropriately configured DER and sufficient inverter power rating and battery energy charge to cover essential loads for a period of time could disconnect from the grid at the building's electric service entrance and initiate islanded operation of the building alone. This is a simpler option because it does not require coordination of multiple DER or use of the distribution system in a way for which it was not designed. This approach could be used widely across the island in the 50% and 75% scenarios, given the number of households and DER ratings contemplated in this study.

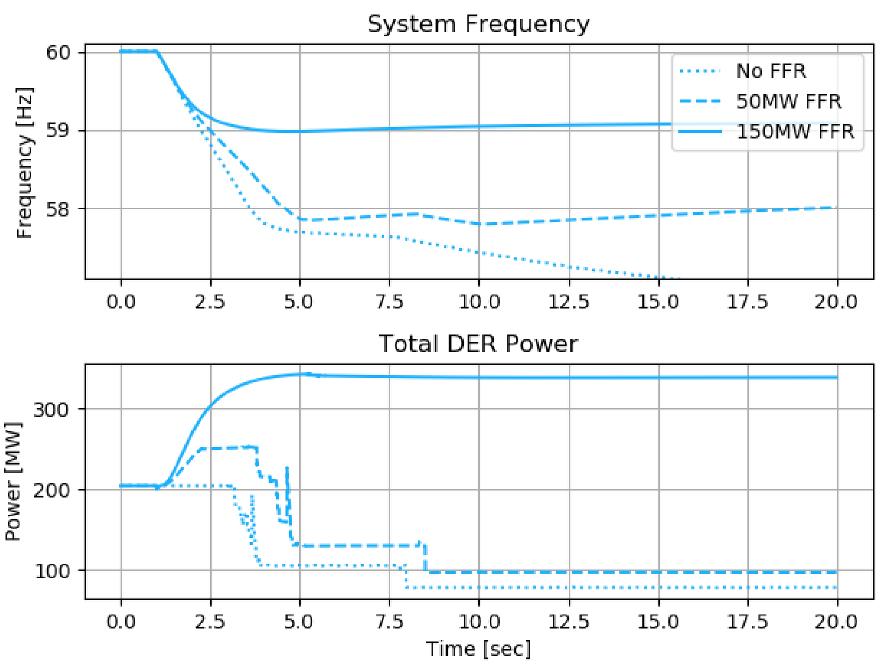

Figure 42: Grid Response to a Loss-of-Generation Event with Varying DER FFR, 50% Scenario

In the 75% scenario, Figure 43 shows the results of a case that considers a loss of the Costa Sur unit 6 dispatched at 410MW, leaving a system inertia level of 4780 MW-s remaining on the grid, which constitutes a very challenging condition. A total of 234MW of UFLS is activated in this case, which sheds a portion of the DER that was helping in the recovery of the grid. Ultimately the grid stabilizes with a peak deployment of nearly 250MW of FFR from DER and a sustained response of nearly 150MW of FFR from DER. However, it is noted that more than 250MW of total FFR are needed prior to the event to achieve this result because a portion of the DER is shed with the UFLS activation.

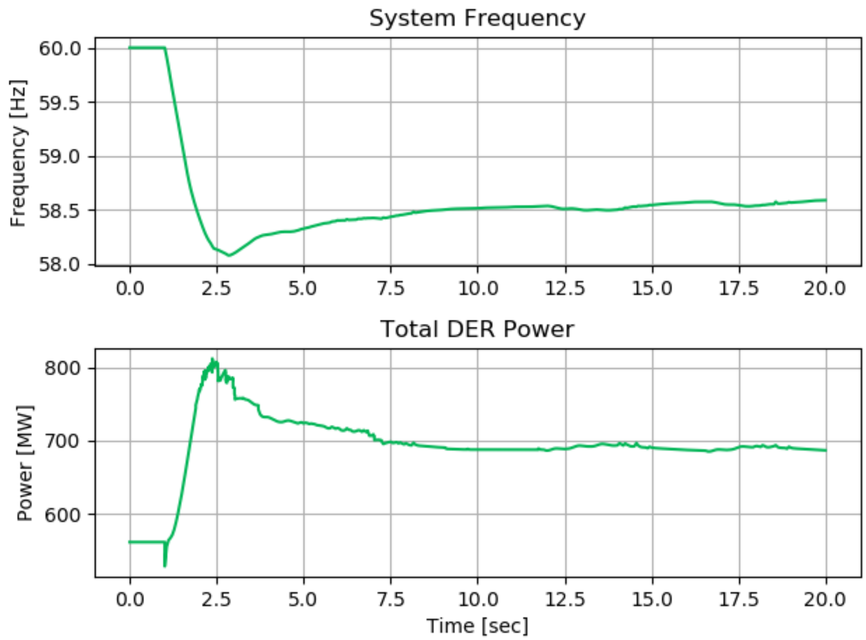

Figure 43: Grid Response to a Loss-of-Generation Event with DER FFR, 75% Scenario

The simulation of the remaining selected cases across all of the scenarios has been performance and the results are summarized and trends are highlighted in Figure 44. On the x-axis, the system RoCoF is plotted, which includes the impact not only of decreasing system inertia but also the MW dispatch of generator tripped, according to the equation:

$$RoCoF = \frac{\Delta P_{generation}}{2H_{sys}}$$

The stability of the system is challenged more for larger losses of generation as well as for lower levels of system inertia, both of which are captured in the RoCoF calculation, so that higher RoCoF values are indicative of more challenging loss-of-generation events. On the y-axis, the maximum deployed FFR is plotted. Each simulation is plotted as a point on the graph that is further color-coded according to the response of the grid in terms of whether the grid survives, and if so, how much UFLS was activated. Finally, the shaded regions of the plot are similarly color-coded to highlight the trends shown by the simulated cases, where the red region shows blackouts expected, the white region shows grid survival with no UFLS, and the yellow and orange regions show the survival with varying levels of load shedding.

As IBRs increase on the grid and conventional generation is displaced, the grid spends more time operating on the right half of the plot shown in Figure 44. If no mitigations were applied, it would be expected that blackouts would occur more frequently for loss of generation events. However, if FFR (note this is only one of many types of mitigation) is applied, it can not only enable the grid to survive loss-of-generation events, but also reduce or eliminate the need for load shedding. It is important to note that correctly applying FFR is not trivial. If the FFR is tuned to be too slow, it will not be effective and the grid may fail to survive the event. However, if the FFR is tuned to be too fast, it may over-react and/or result in oscillatory behavior and participate in adverse interactions with other grid equipment, destabilizing the grid and ultimately leading to a failure to survive the event.

It is also important to note that this graph and these results are based having some synchronous machines online. These results do not necessarily apply to an all-inverter based system, as will be discussed in more detail in Section 6.6.

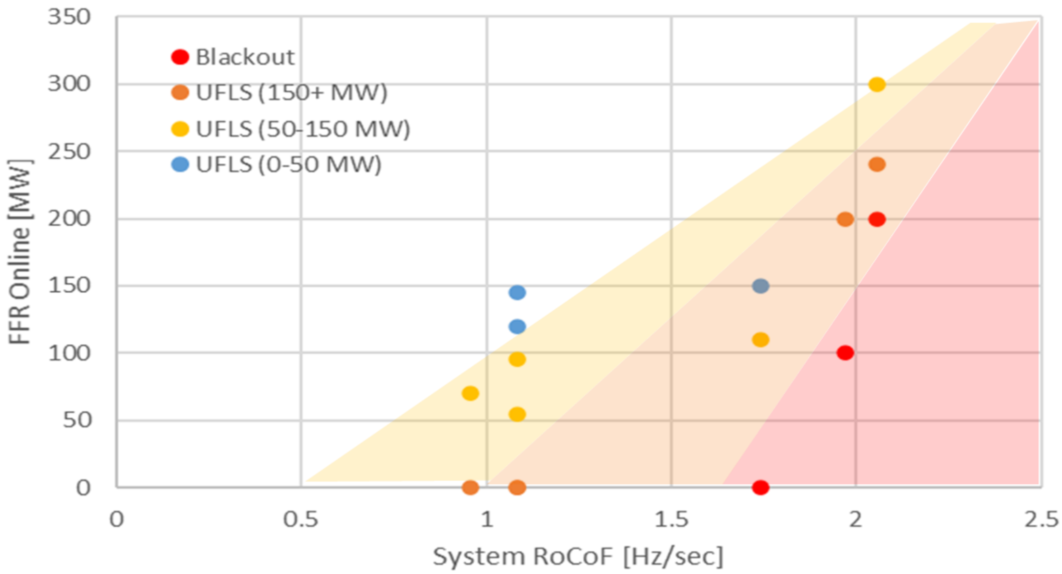

Figure 44 : Summary and Trends Identified from Loss-of-Generation Events

6.5 Fault-and-Clear Scenarios

A grid fault simulation result is shown first for the current scenario with a fault on the Costa Sur – Mayagüez 230kV transmission line in Figure 45 and Figure 46. At the onset of the fault, which is applied at 1.0 seconds, the voltage on the 230kV system is pull down below 0.5pu across the island. As a result, the electrical power being transmitted drops and there is an acceleration of the synchronous generators which results in an increase in grid frequency. As the fault is cleared, voltage quickly recovers, as does active power, which contains some damped oscillations due to the interaction of synchronous machines on the grid.

As shown in Figure 46, the DER also see very low voltages, which causes a reduction in active power. The DER are configured to provide voltage support for large voltage excursions, which can be seen by the attempt to increase reactive power output while voltages are low. After the fault is cleared, voltage return to a normal range and reactive power returns to its pre-fault level. Active power also decreases briefly due to the FFR functions acting to correct the over-frequency event. This performance is expected and is generally considered good.

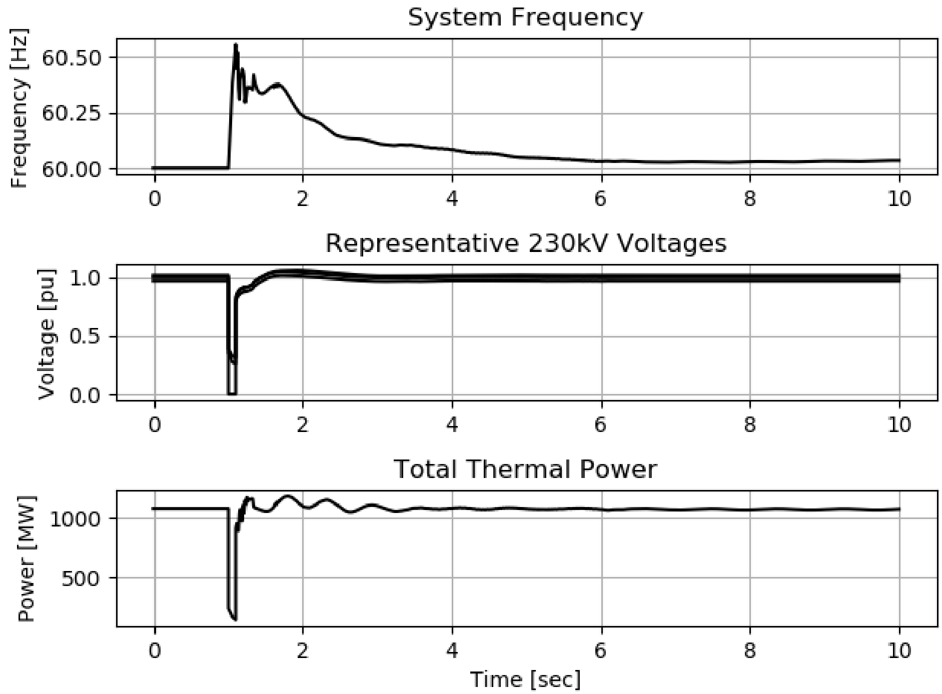

Figure 45: System-Level Response to a Fault Event, Current Scenario

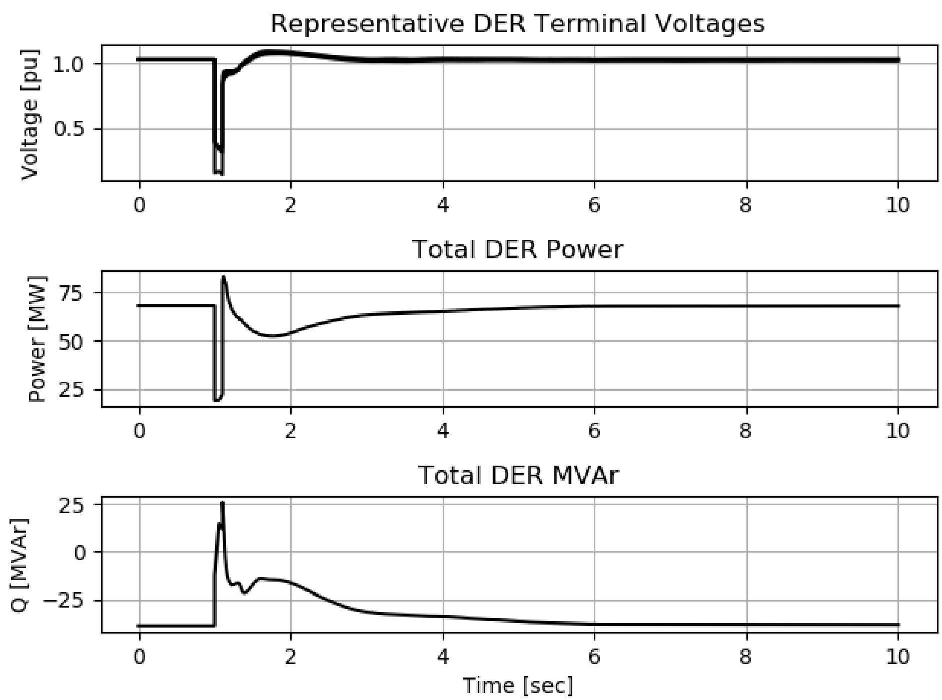

Figure 46: DER-Level Response to a Fault Scenario, Current Scenario

Next, the 50% scenario is assessed for two variations in DER configuration, which is shown in Figure 47, where the magenta trace shows the results from the same fault (Costa Sur – Mayagüez) and same DER configuration that was used in the current scenario shown in Figure 45 and Figure 46. This DER configuration already included FFR and volt-var response as well as ride-through protection settings consistent with modern values like California's Rule 21 and Hawaii's Rule 14H. However, this DER configuration reaches its limits for this 50% scenario case.

Unlike with the current scenario case where the synchronous ratio was 12.0, this 50% scenario case has a synchronous ratio of 2.0, meaning there is a significantly reduced presence of synchronous machines online, which is broadly in the direction of creating "weak grid" conditions. The weak grid conditions mean that there is less fast-acting voltage support typically provided by synchronous machines. This reduced support is manifested by the delayed recovery of voltage following fault clearing, as shown between 1 and 3 seconds in the simulation in Figure 47. This delayed voltage recovery is due to the stalling and re-starting of induction motor loads like residential air conditioners, which are represented by the dynamic composite load model. As the voltage gradually recovers, it achieves a level where the motor loads re-start, which results in a reduction in reactive power consumption and an increase in system voltage. The increase in voltage is seen across the system, including at the DER voltage levels. Despite the DER's attempt to control large voltage excursions (outside a +/- 5% of nominal) with their volt-var control functions, the high voltages persist above 1.1pu for over one second, causing most of the DER to trip. The sudden loss of power generation from the DER appear to the grid like an extremely large loss-of-generation event where there is no FFR from the DER available to arrest the decline in system frequency, resulting in a grid blackout.

However, by further increasing the volt-var response provided by the DER and expanding the over-voltage protection settings to tolerate 1.19pu voltage at the DER terminals for up to 4 seconds, the DER are able to ride-though and continue providing essential support to sustain the grid and its recovery, as shown in the solid blue traces of Figure 47.

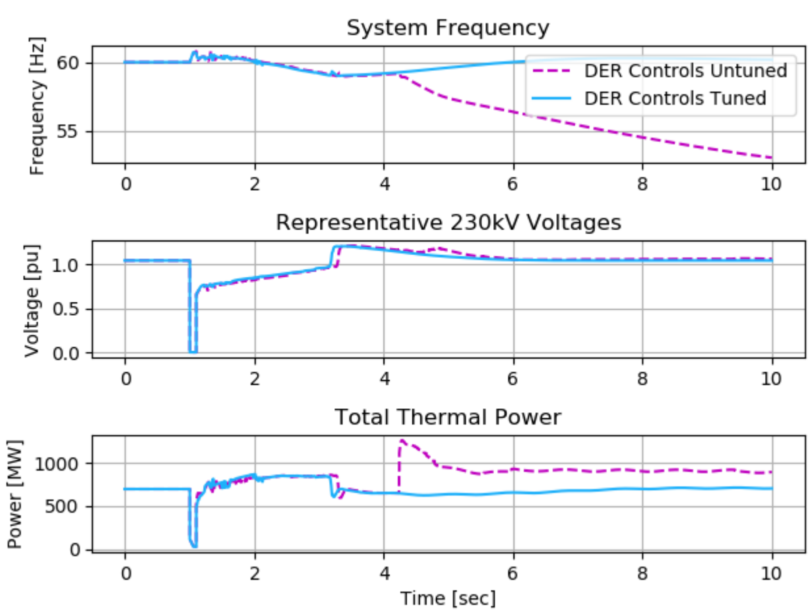

Figure 47: Grid Response to a Fault Event, Varying DER Controls, 50% Scenario

A fault on the double-circuit 230kV transmission line is evaluated for the same case of the 50% scenario as shown in Figure 47, where the results are plotted in Figure 48. Both traces of simulation utilize the best DER controls configuration, informed by the results of prior simulations. However, the difference between the magenta simulation, which shows a dramatic problem, and the blue simulation which shows reasonable response and survival of the system is the simulation time-step applied to the dynamic simulation in PSSE. The typical ¼ cycle time step used in most fundamental frequency dynamic simulation tools has been applied throughout these simulations and is used for the magenta simulation. For the blue simulation, a 1msec time step is used. The results of a model should not vary for small changes in time-step, and the fact that the result changes so dramatically indicates that these simulated grid conditions are beyond the capability of the simulation tools. While a more capable and detailed model may corroborate the survival shown in the blue trace, this cannot be assumed.

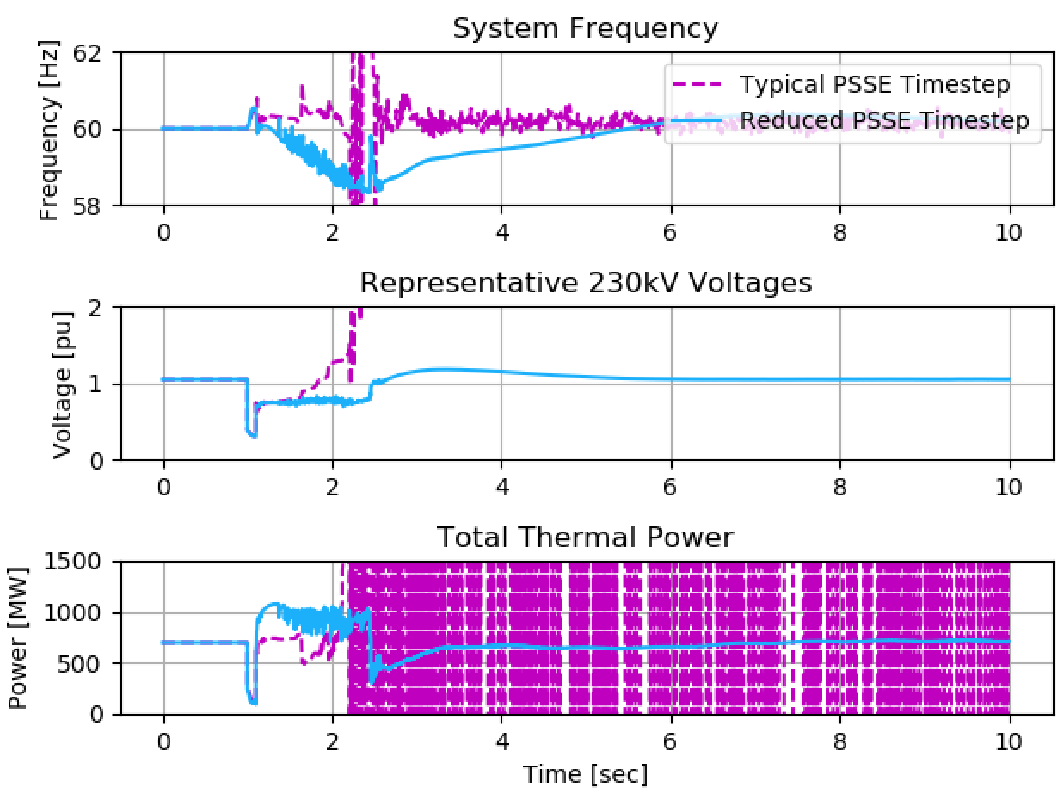

Figure 48: Grid Response to a Fault Event, Varying Simulation Time Step, 50% Scenario

The simulation of a case from the 75% scenario with a synchronous ratio of a mere 0.1 as shown in Figure 49 for both a typical time-step and a reduced time-step both show divergent numerical behavior, indicating that such scenarios are simply beyond the capability of the positive-sequence fundamental-frequency simulation tools, a result that was expected. Therefore, the stability of the grid for fault conditions for the very high IBR cases common in the 75% scenario cannot be evaluated in PSSE. Alternative methods for evaluating these cases are discussed in Section 6.6.

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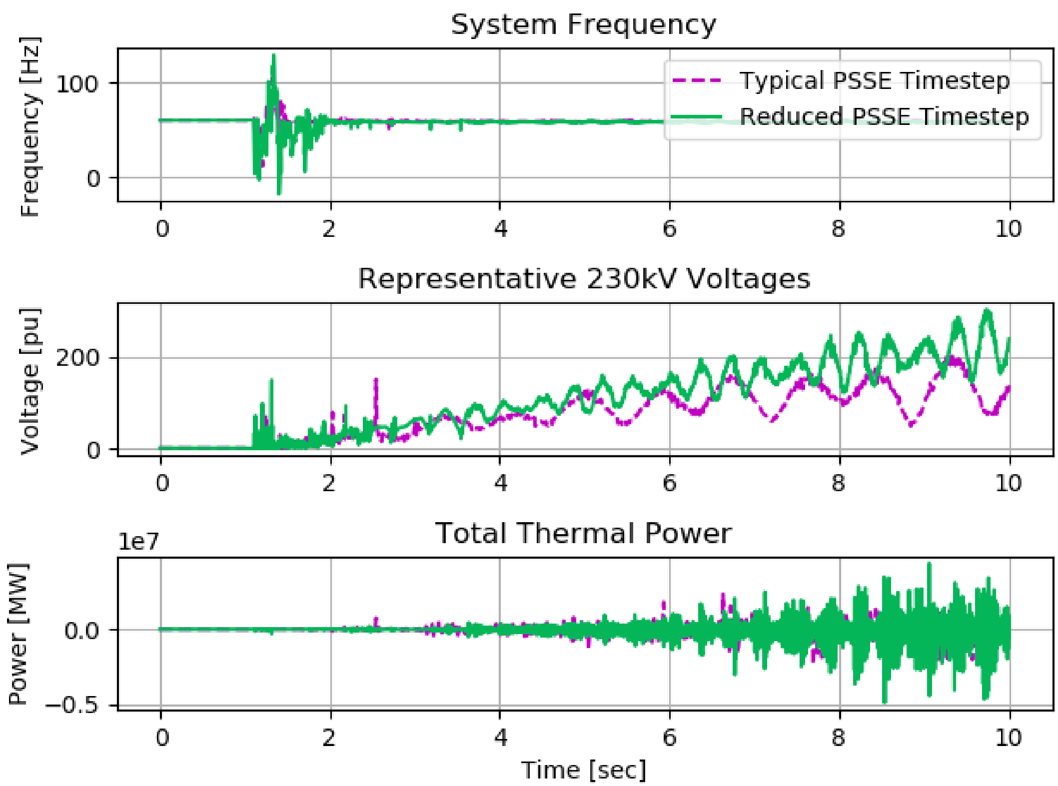

Figure 49: Grid Model Response to a Fault Event, Varying Simulation Time Step, 75% Scenario

A large set of simulations was performed for six different grid faults across cases from each scenario with various DER configurations in order to capture a broad range of operating conditions and identify the most effective DER control settings. The results are simplified and summarized in the following figures, which are color-coded as follows:

- Green cells for in cases where performance is considered good, similar to that shown in the current scenario in Figure 45.
- Orange is used for marginal performance where the grid survives but with some loss of DER and/or loss of load.
- Red is used for cases in which the system does not survive the fault event.
- Brown is used for cases in which there is evidence that the simulation tool is not capable of accurately simulating the event, as in Figure 49.

The following summaries including Figure 50, Figure 51, and Figure 52 show the evolution of DER controls and the resulting improvement in performance of the grid in response to transmission fault events. Beginning with basic implementation of "smart-inverter" functions and ending with tuned smart-inverter functions and reasonably expanded protection settings, the performance can be greatly improved.

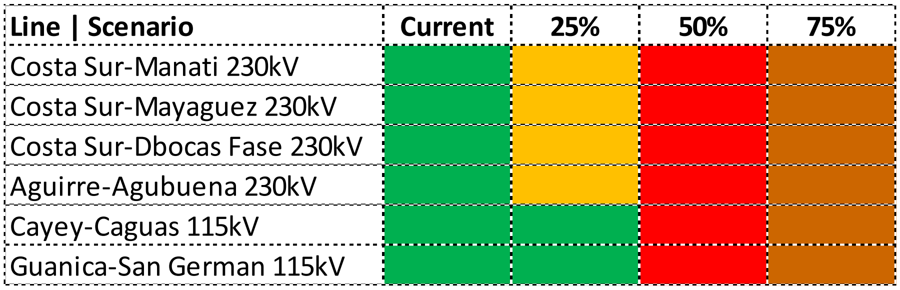

Figure 50: Performance Summary for Grid Faults with Basic DER Functionality

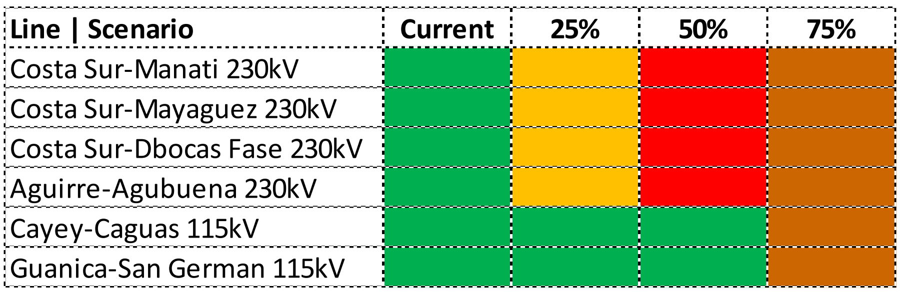

Figure 51: Performance Summary for Grid Faults with FFR and Improved Volt-Var DER Functionality

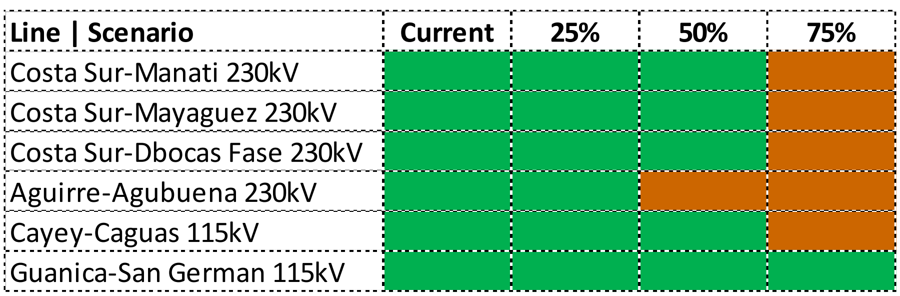

Figure 52: Performance Summary for Grid Faults with FFR and Improved Volt-Var and Expanded Over-Voltage Protection from DER

6.6 Very High Penetration Scenarios

Very high penetration of inverter-based resources like solar PV, battery energy storage, wind and whether or not they are distributed or utility-scale resources are challenging to grid operations for reasons of grid stability and resource adequacy. For resource adequacy, long-duration (multi-day) storage would be needed to cover outlier weather events where wind and solar resources may be very low for consecutive days or weeks. While there is plenty to be discussed on resource adequacy, this section will focus on the challenges due to grid stability.

High penetrations of IBR challenge grid stability because it typically implies that there are relatively few conventional synchronous-machine-based resources online, which provide important stabilizing benefits to the grid. The primary stabilizing characteristic of synchronous machine technologies is that they provide short-term (fractions of a second) storage of energy with a very high capability to release the energy (maximum currents that are multiples of their rated currents). The short-term energy reservoir in synchronous machines comes in two forms: the rotational energy of the spinning rotor and drivetrain and the magnetic field energy in the steel core of the generator. The rotational energy, typically described as inertia, acts to stabilize grid frequency during sudden changes in the power balance on the grid, like for loss-of-generation events. The magnetic field energy helps to provide a constant "voltage anchor" for the grid.

Today's inverter-based resources are designed to expect the grid to have these characteristics of inertia and "voltage anchors," and therefore, they rely on a certain level of synchronous machine technology to be connected to the grid with the IBRs. If today's IBR are connected to a grid that does not exhibit enough of these characteristics (ie. because there are too few synchronous machines online), then disturbances like a loss-of-generation will cause the grid to "move" or change state too quickly for the IBR to respond in a stabilizing way to support the grid. The result is typically a disconnection of the IBR and a lack of support to the grid that ends is partial or complete blackout.

There are two general approaches for enabling very high levels of IBRs on a grid. One approach is to improve the design and behavior of the IBRs such that they provide the inertia and "voltage anchor" characteristics that support the grid similar to the way synchronous machines do. This concept has been termed "grid-forming" inverter technology by in the industry. The second approach is to maintain the inertia and "voltage anchor" characteristics of the grid by keeping a sufficient number of synchronous machines online. Both approaches are briefly discussed.

Grid-forming inverter technology is in its infancy as of this publication. The primary thrust is in re-writing the inverter's software-defined controls so that the inverter provides the instantaneous inertial response and voltage support that synchronous machines do. However, this task is not easy for inverter manufacturers. Not only is it a fundamentally different control strategy than what has typically been used, but the response – and therefore, the effectiveness on the grid – is still subject to the inverter's hardware limitations in terms of current-handling capability and access to short-term energy reserves. On the grid operations and planning side, there is the challenge of specifying the technical needs from advanced grid-forming IBR in order to have a system that is stable and can achieve higher levels of renewable penetration. The inverter technology and application development is a journey. It will not simply be flipping a switch over to grid-forming inverter technology and going straight to 100% inverter-based grid operation. But in the time-frames discussed, it is achievable.

The second approach of utilizing synchronous machine technologies to provide the needed grid-stabilizing characteristics can be done a few ways. One way is to maintain a minimum level of conventional resources online when committing and dispatching conventional generation. This is often described as designating some conventional units as "must-run" units. This approach almost always costs more to run the grid because units that would be economically decommitted are now forced to run, causing the remaining units or less expensive units to be run at lower outputs or at less efficient operating points. This approach is evaluated in Section 7.1 as a production cost sensitivity.

Another method is to use synchronous condensers to provide the synchronous machine characteristics and not modify the dispatch and commitment decisions, which can be left economically optimized. A synchronous condenser is essentially a synchronous generator without a turbine attached that is connected to the grid and rotating synchronously with the grid. Without a turbine attached, it cannot generate power and it does not burn fuel. But it does provide inertia and “voltage anchor” support to stabilize the grid, as well as steady-state reactive power support. Synchronous condensers have some relatively small losses, which must be provided by the grid, so they consume some power any time they are operating. Synchronous condensers can be procured and commissioned as new units, or existing power plant generators can be converted to synchronous condensers, often for substantial cost savings. However, synchronous condensers can introduce their own stability challenges and cause power system swings, which should be studied and understood in advance.

6.7 Summary

The grid stability analysis shows that as the penetration of inverter-based resources increases, the challenges to maintain grid stability, especially in the face of significant disturbance events like a loss-of-generation or a grid fault, become more acute. To make this more concrete, the grid stability challenges have been distilled into two factors: (1) system inertia or “H” [MW-s] and (2) Synchronous Ratio. The duration curve of inertia and the synchronous ratio are plotted for each of the four scenarios evaluated in Figure 53. As expected, higher-penetrations of IBR are associated with lower values of inertia and lower synchronous ratios, and are therefore more challenging to the stability of the grid.

In Figure 53, three levels of grid stability risk are shown color-coded as white, yellow, and red. In the white region, risk is considered low as this is a region where conventional power plants dominate the grid and conventional planning and operating practices are effective in maintaining stability. The current scenario has nearly all hours of operation in this low-risk region.

The next risk region is yellow, indicating higher levels of risk to grid stability and a significant change to traditional grid planning and operating practices. This analysis finds that through utilization of advanced inverter functions (like FFR and volt-var) and careful configuration of DER protection and response characteristics, the grid can be stable in the yellow region. This region is where the 25% and 50% scenarios have the bulk of their operating conditions.

Finally, the highest risk for grid stability is indicated by the red regions. This region is characterized by inverter-dominant grid operations and requires new methods, approaches, utilization of technologies, and analytical tools to achieve acceptable levels of stability and reliability. These may include dynamic and probabilistic planning and stability assessments, use of emerging inverter technologies like grid-forming technology, and the use of detailed electromagnetic transient simulation tools. In addition, conventional synchronous machine-based technologies like synchronous condensers can be deployed in conjunction with the other new technologies to help serve as a bridge to the new future grid.

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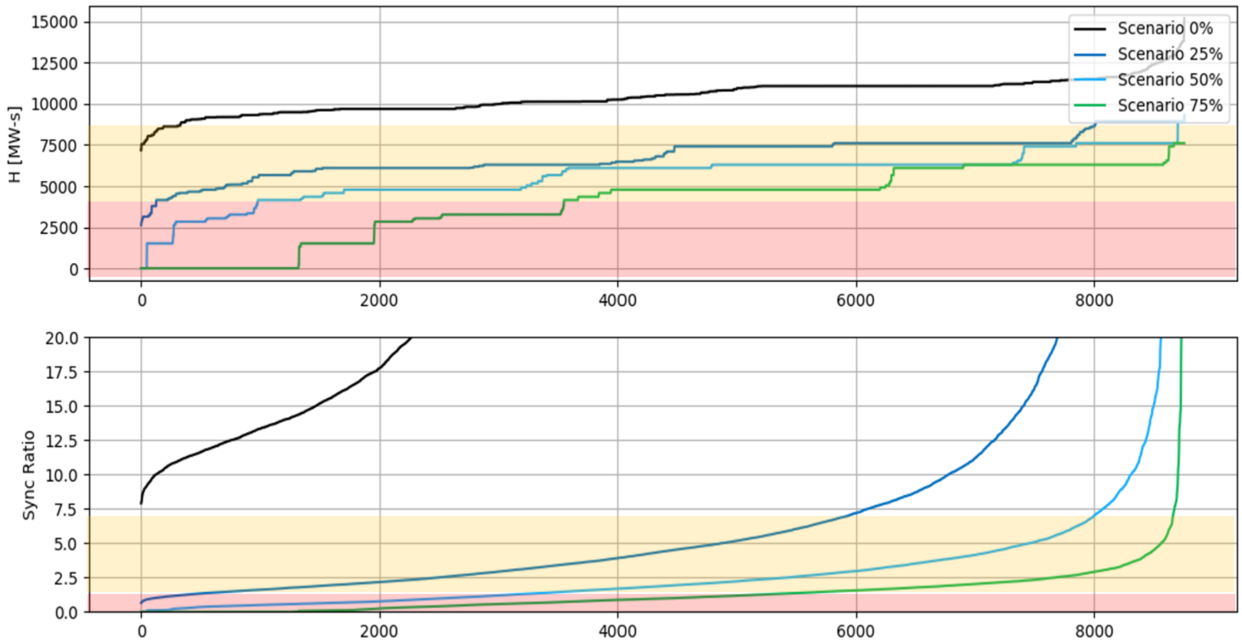

Figure 53: Summary of Risk Considering the Maturity of Inverter Technologies in 2020

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7 Sensitivity Analysis

7.1 Grid Stability Sensitivity

As Section 5.5 indicates, the DER scenarios quickly reach periods of very high instantaneous inverter-based generation. This would represent some of the highest levels of IBR integration seen anywhere in the world today and could pose a reliability risk if unmitigated. To operate reliably at these levels would require one of three options:

- Grid-forming inverter technology that does not require synchronous generation to operate, but is currently being developed and is in commercial infancy,
- The addition of synchronous condensers, a mature technology commercially available today,
- Operational changes that commit additional synchronous generators to maintain a minimum inertia level, which would lead to solar curtailment.

Each of these mitigations comes at cost, and preference is given to grid-forming inverter controls because would not require significant capital expenditures like synchronous condensers, or increased fuel consumption and curtailment like operational changes. However, a sensitivity was evaluated to simulate the effects of grid stability constraints. This provides a clear example that reliability can be maintained even at very high DER integration if grid-forming technologies are not made available and synchronous condensers are not installed. This is especially useful to show the effects of grid stability constraints on near-term DER integration.

The Grid Stability Sensitivity is built around implementing two separate constraints within the PLEXOS model. These system constraints are informed by the initial results of the grid stability analysis conducted in PSSE (see Section 6). The first constraint requires unit commitment to maintain system inertia above 4,000 MW-s. The second constraint requires system dispatch to maintain a synchronous ratio of greater than 1.5. The synchronous ratio is measured as the relative difference between the thermal units' MVA contribution and the net-generation of inverter-based resources (IBR). These constraints will work together to put bounds on the operation of the system that ensure a greater level of reliability without relying on the introduction of grid forming inverters or synchronous condensers, as assumed across all Base Cases.

As discussed in the grid stability analysis the 75% DER is the most effected case. The high penetrations of IBR results in extended periods of low system inertia. Figure 54 shows that in the 75% DER Base Case the system inertia was less than 4,000 MW-s for more than 3,500 hours of the year. In the Grid Stability sensitivity all hours where above 4,000 MW-s and almost all were higher than the same hour from the Base Case even if it was already above 4,000 MW-s. This is primarily due to the inclusion of the synchronous ratio constraint which is shown in Figure 55. While the system inertia was below the target of 4,000 MW-s for roughly 3,500 hours in the base case, the synchronous ratio was less than 1.5 for close to 6,200 hours.

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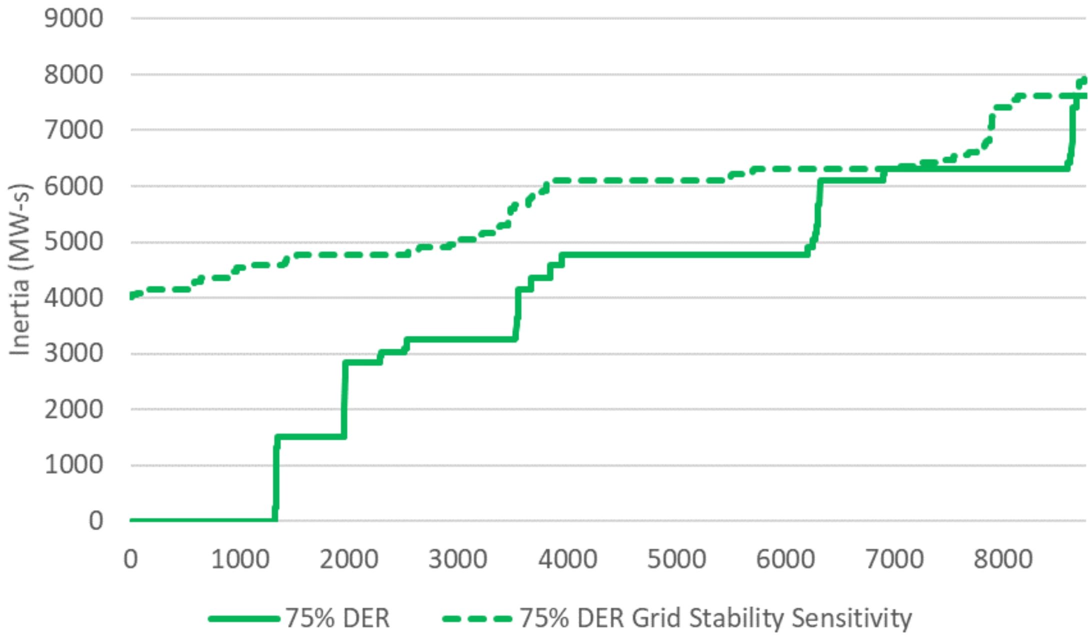

Figure 54: Duration Curve of System Inertia

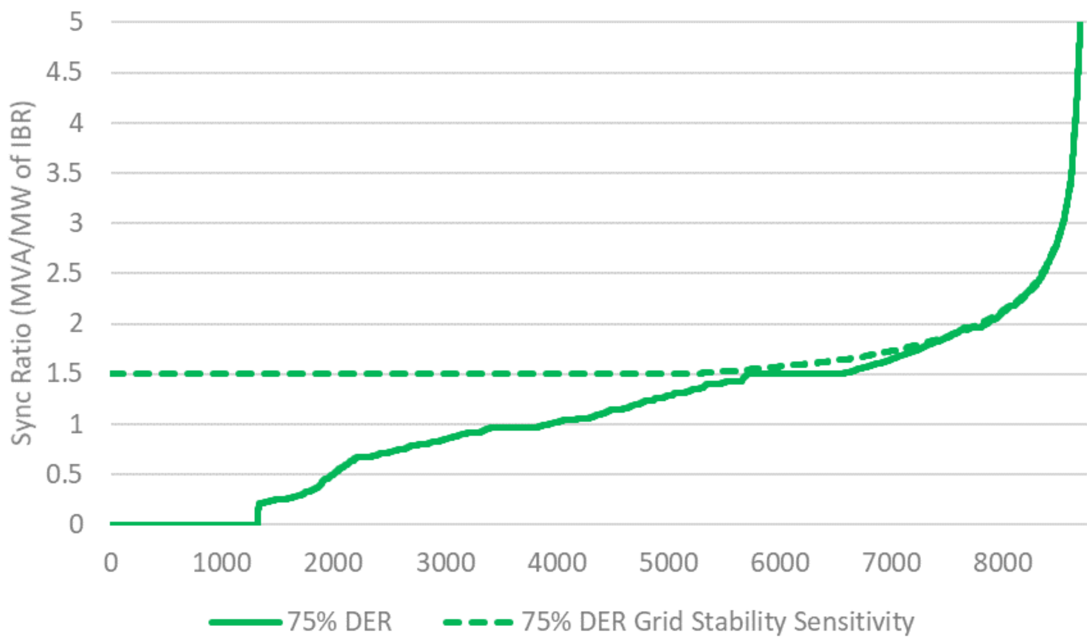

Figure 55: Duration Curve of Synchronous Ratio

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These constraints had little impact on the Base Case, 25% DER, and 50% DER cases as can be seen from the little to no change in annual net generation between the cases in Figure 56. There are small changes in the 50% DER case but it is not until the 75% DER case that the Grid Stability sensitivity shows meaningful differences from the 75% DER Base case. There is an increase in generation from Combined Cycle, ST, and GT units in the Grid Stability sensitivity. This makes sense as these units are committed more often to ensure enough thermal generation is online to maintain adequate system inertia and synchronous ratio. With this increase in thermal generation there is a requisite decline in solar generation and an increase battery usage.

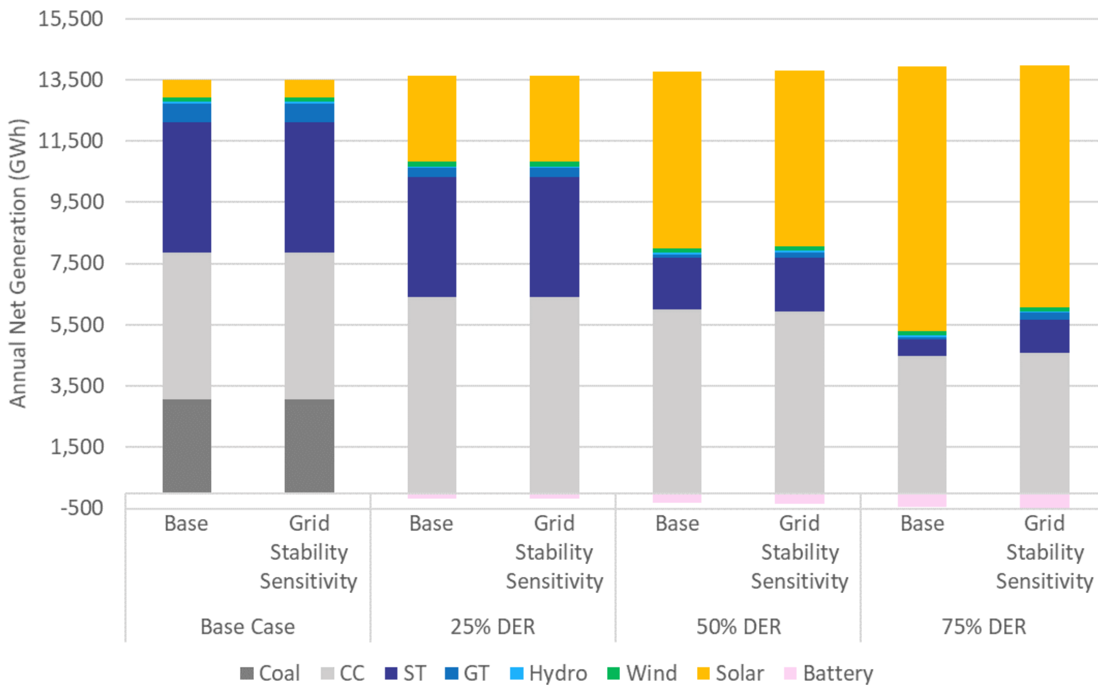

Figure 56: Annual Net Generation for Base cases versus Grid Stability Sensitivity

As more thermal generation is kept online during the peak hours of solar production to ensure grid stability there is an uptick in curtailment of IBR. Figure 57 shows that there is no difference in curtailment for the Base Case and 25% DER cases. While the 50% DER case has a slight increase from zero curtailment to less than 1%. The 75% DER case experiences a more significant increase in curtailment, going from roughly 1% to about 9.5%. Although this increase is more substantial than the other three cases the absolute amount of curtailment of only 9.5% is still reasonable for a system with 75% of its energy coming from renewable resources.

This increase in curtailment was lessened by more fully utilizing the battery resources on the grid. This can be seen by comparing the average number of cycles per year the batteries go through between the two case, as shown in Figure 58. Again the 25% DER case shows little to no change, but the 50% and 75% DER cases both have noticeable increases in the number of cycles the batteries go through per year. This is because the thermal generation is not backing down during the middle of the day as much in the Grid Stability sensitivity so the solar power is displaced and can no longer be consumed by the grid. Instead as much of it as possible is going into the batteries for use later in the evening.

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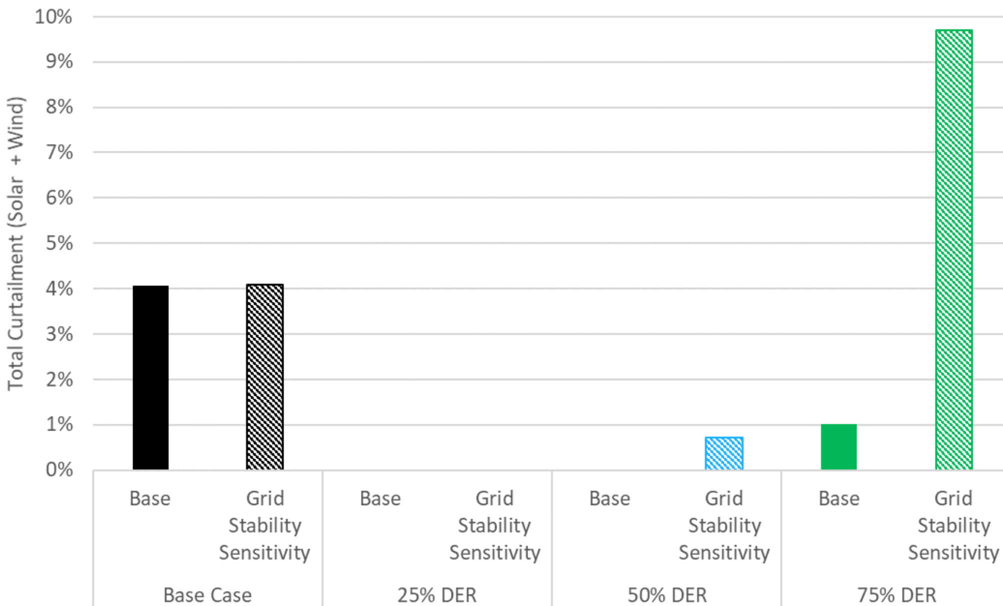

Figure 57: Total Renewable Curtailment

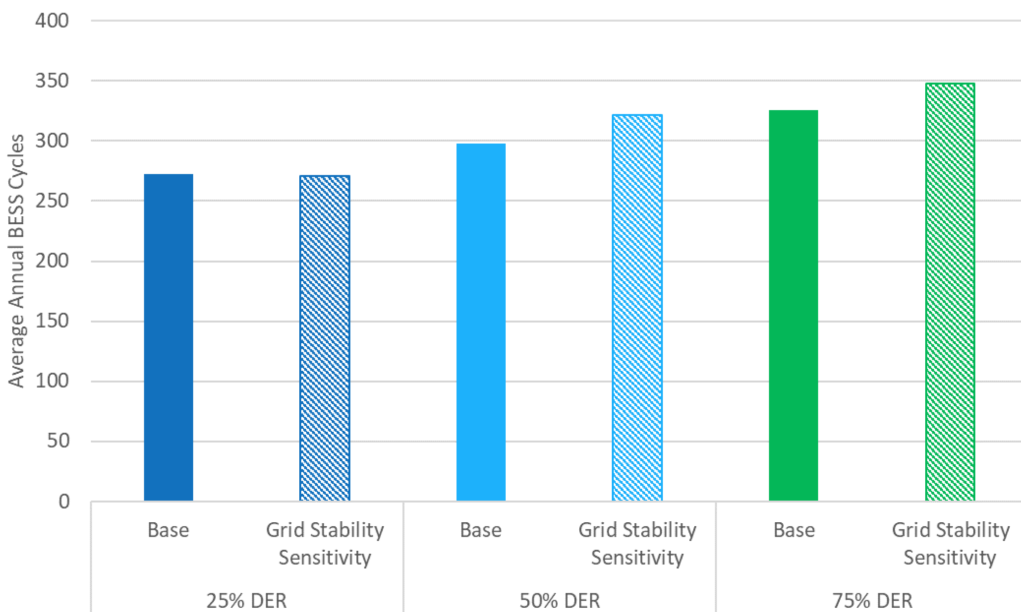

Figure 58: Average Battery Cycles per Year

These changes in operating behavior are apparent when comparing the dispatch of the two 75% DER cases for just a 3-day period, as shown in Figure 59. In the 75% DER case each of the three days experiences an extended period of little to no thermal generation in the middle of the day. However, in the Grid Stability sensitivity these periods are eliminated and an ample amount of thermal generation across multiple unit types remains online across all hours of the day. The increase in battery usage is also apparent as total generation in the Grid Stability sensitivity nears 4,000 MW each of the three days, whereas in the 75% DER Base case the peak is not much higher than 3,500 MW. This change is wholly from the battery being utilized more as Net Load remains unchanged between the two cases.

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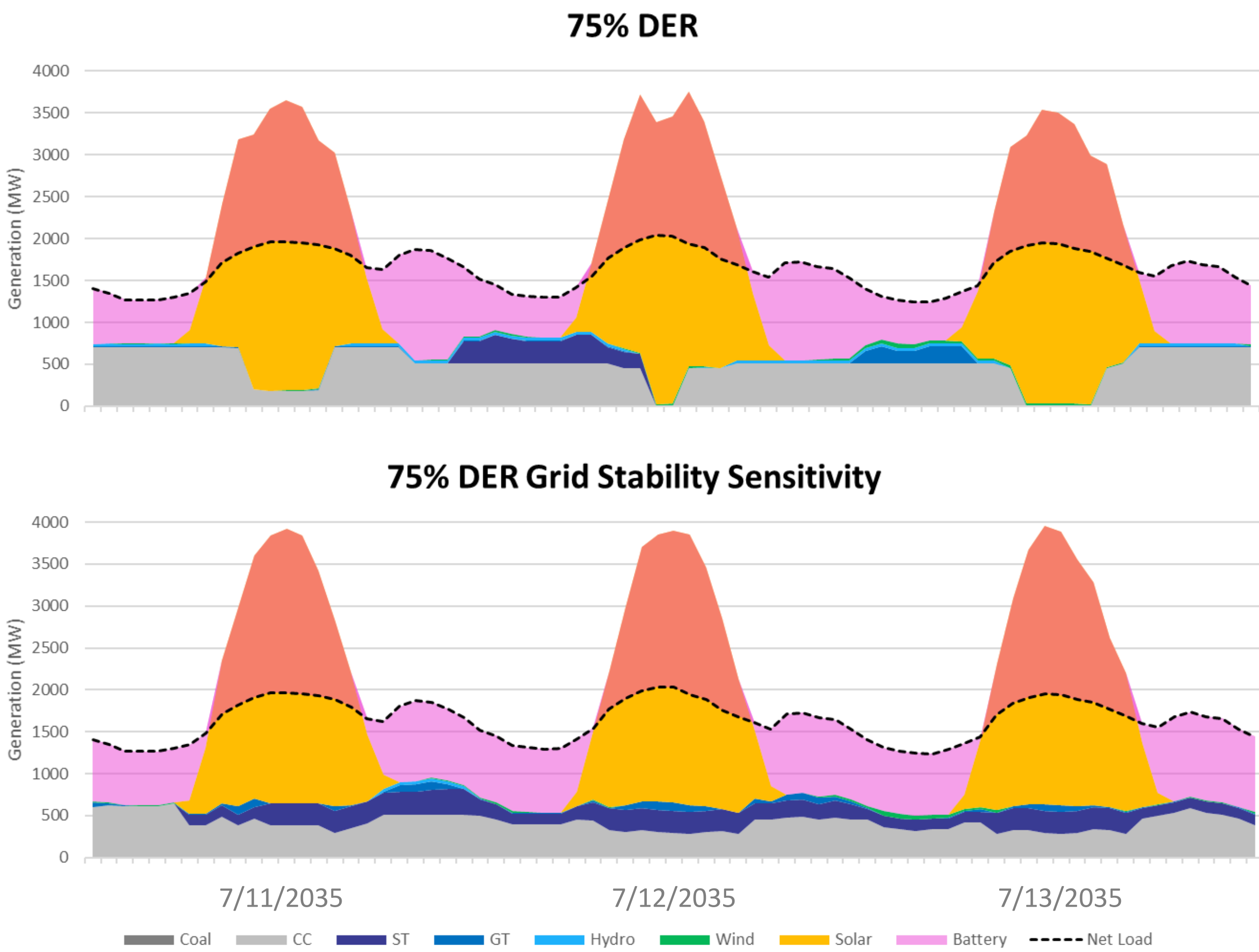

Figure 59: Dispatch Diagram of 75% DER cases from July 11th to July 13th, 2035

On a cost basis the trends discussed above continue to hold. When comparing the total system cost (fuel costs, VO&M costs, and start costs), as shown in Table 13 there is little change in the Base Case and 25% DER. In the 50% DER case the total system costs only increase about $11 million, but in the 75% DER case the costs increase more than $127 million per year. Although this is a significant increase from the 75% DER Base case it is important to note that even with that increase it is still a more substantial decline from any of the three other cases. In addition, this demonstrates that operational changes can be an effective – and economic -mitigation strategy for managing grid stability at lower DER integration levels.

Table 13:Total System Cost between the Base Cases and Grid Stability Sensitivity Cases

Scenario	Base Case		25% DER		50% DER		75% DER	
Sensitivity	Base	Grid Stability Sensitivity	Base	Grid Stability Sensitivity	Base	Grid Stability Sensitivity	Base	Grid Stability Sensitivity
Total (real 2020 $millions)	1,086	1,086	989	990	732	743	473	600

7.2 AES Accelerated Retirement Sensitivity

In addition to the Grid Stability Sensitivity, a sensitivity evaluating an accelerated retirement of AES was conducted. The study year for all previous cases has been 2035, but for the purposes of this sensitivity a study year of 2024 was chosen. On the basis of PV and storage deployment, this represents a realistic timeline for the retirement of both AES units from the system. Based on this view an updated load profile was created to reflect expected load in 2024. In Table 14 the total annual sales assumptions for the AES Accelerated Retirement Sensitivity is compared against the 2035 Load used in all other cases. The 2035 load includes reaching a 25% energy efficiency target by 2035. As the 2024 load is an intermediate step an energy efficiency target of 11% was used. For more discussion on this please refer to the subsequent report by EFG.

Table 14: AES Accelerated Retirement Sensitivity Load Assumptions

	2035 Load	AES Accelerated Retirement (2024) Load
Total Annual Sales (GWh)	11,736	13,932

Just as load was adjusted to match the updated study year of 2024 the buildout of DPV and batteries has been adjusted to reflect what can reasonably be assumed to be completed by 2024. The starting point for this intermediate DER buildout is the 25% DER case as it represents the most achievable buildout in the near term. The updated buildout is outline in Table 15. The AES Accelerated Retirement Sensitivity only evaluates the effects of AES 1 & 2 retiring from the system, unlike the other retirements outlined in Section 2.3.

Table 15: DER Buildout Assumptions for the AES Accelerated Retirement Sensitivity

	25% DER Base Case	AES Accelerated Retirement Sensitivity
Residential DPV (MW)	1,350	614
Commercial DPV (MW)	142	65
Battery (~4.5 hours) (MW)	1,179	442

For comparison purposes the sensitivity results also include an updated Base Case run which used the increased load from Table 14. This will allow for a direct comparison of how a system with today's composition compares with one that has added DER capacity and retired AES.

With the retirement of AES the AES Accelerated Retirement Sensitivity case shows a significant increase in generation by CC units, as shown in Figure 60. This is in line with what was seen in the main results in Figure 15. However, with only an intermediate buildout of DER capacity as compared with even the 25% DER base case there is also a significant increase in generation by ST units. With the retirement of AES the system lost 454 MW of capacity. This capacity was replaced with more than 500 MW of DPV and another 442 MW of ~4.5 hour batteries. However, even though a greater amount of capacity was added to the system than retired the capacity factor of the units added is much lower than that of AES. From a reliability standpoint each system evaluated below saw zero instances of unserved energy or reserve shortages, but the DER added to the system still does not produce enough energy to fully replace AES's generation. Therefore, ST units have taken a greater role in generation than in previous cases to fully replace the energy once provided by AES.

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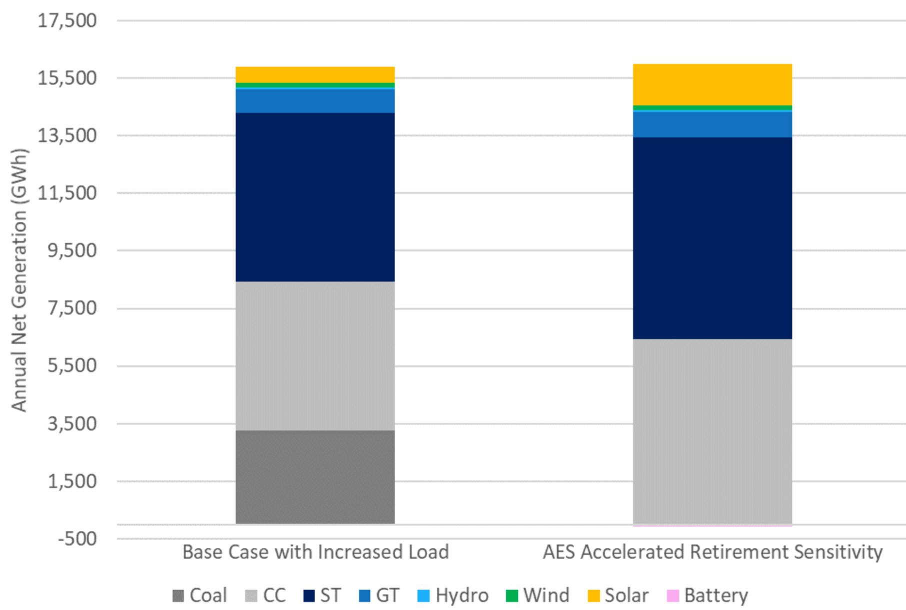

Figure 60: Annual Net Generation for the AES Accelerated Retirement Sensitivity

Total System Costs show a similar trend with the AES Accelerated Retirement Sensitivity resulting in roughly $68 million of increased costs, as shown in Table 16. This increase in costs is mostly from oil-fired (primarily ST units) generation replacing lower cost coal-fired generation.

Table 16: Total System Costs for the AES Accelerated Retirement Sensitivity

	Base with Increased Load	AES Accelerated Retirement Sensitivity
Total System Costs (real 2020 $millions)	1,349	1,417

Dispatch diagrams highlighting the same weeks as those shown earlier are included in Figure 61 and Figure 62. Please note that although these are the same weeks previously highlighted in Figure 18 and Figure 19 the load for the cases below was scaled higher to reflect the expected conditions for the study year 2024. As noted earlier, both CC and ST units are being dispatched more often with the retirement of AES. Even with less DER on the system than previously evaluated cases the presence of more solar and batteries is clear in the AES Accelerated Retirement Sensitivity. Unlike in the previous evaluated cases there are hours shown below where batteries are charging off of thermal generation instead of almost entirely off of solar. This shift is most likely due to the more limited amount of generation from solar in this case versus the three main DER cases. And ties back into why ST units play a more significant role in the system as discussed above.

Overall, the accelerated retirement of AES is feasible with an incremental buildout of DER to help replace lost capacity. The system will be able to properly operate and meet demand throughout the year.

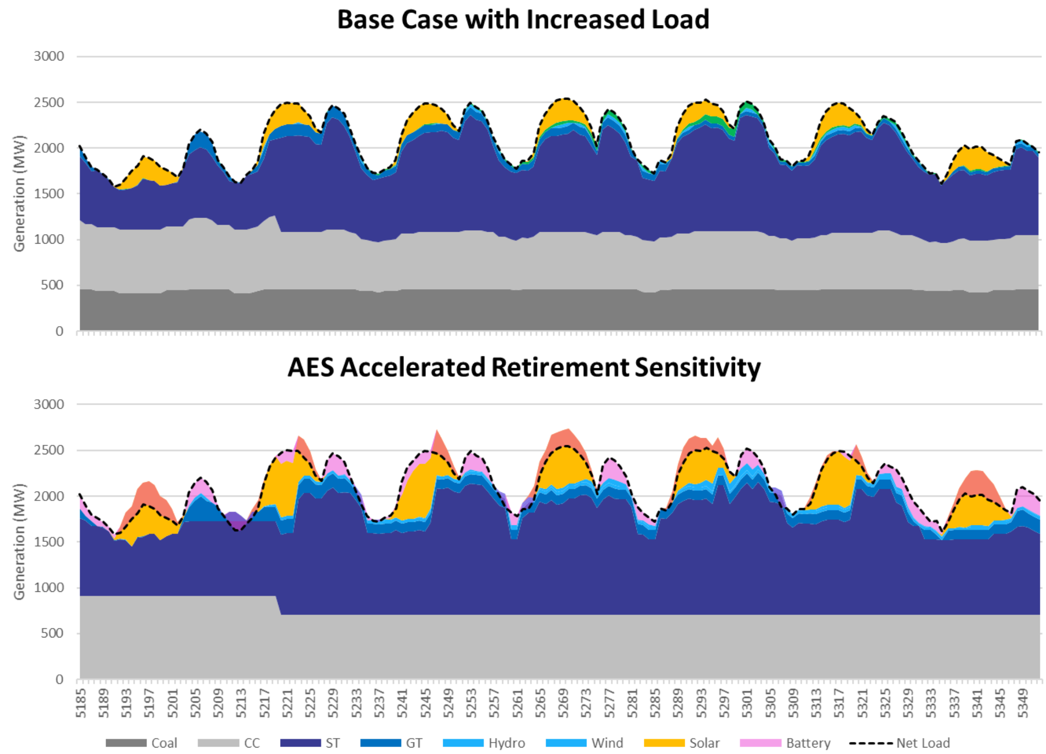

Figure 61: Dispatch Diagrams, AES Retirement Sensitivity, Peak Load Week (Aug 5)

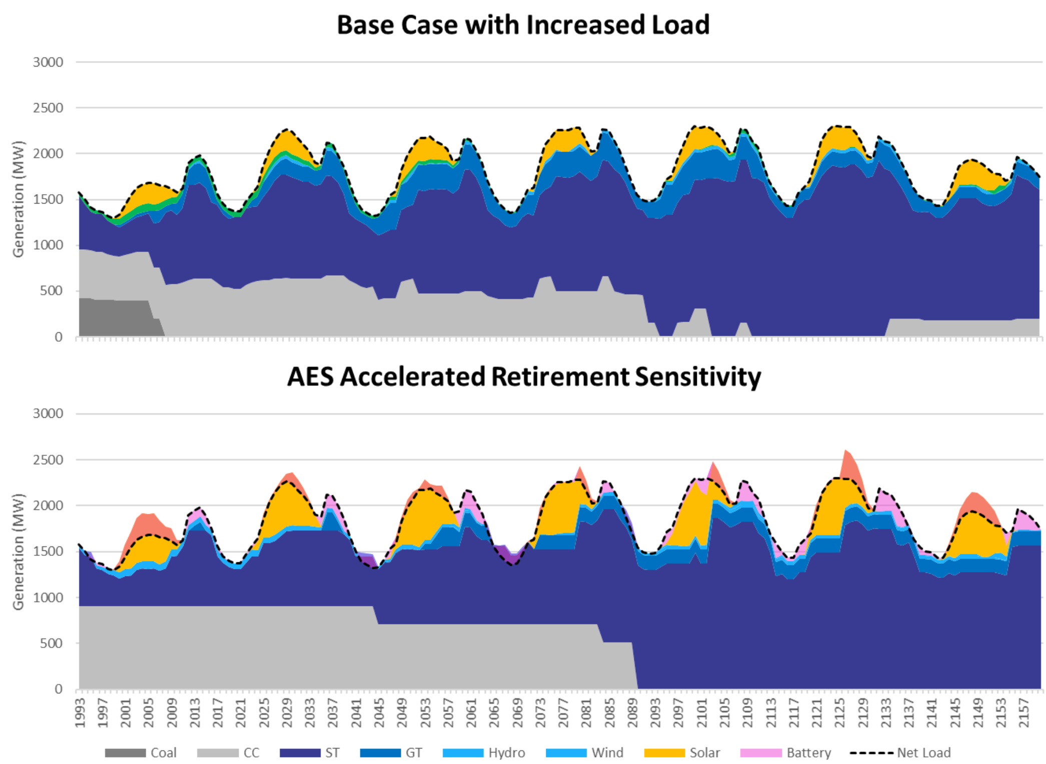

Figure 62: Dispatch Diagrams, AES Retirement Sensitivity, Max Renewable Week (Mar 25)

8 Mitigations and Recommendations

Integrating significant levels of distributed energy resources can be accomplished in an economic manner that improves reliability, resiliency, and grid stability. However, this transition will require changes to operational practices as well as investments in generation, transmission, distribution, and enabling technologies. Some of these mitigations are provided in the list below.

- Increased flexibility of the conventional fossil fleet will become increasingly important. Investments to increase flexibility, specifically part-load operation and cycling, should be evaluated to ensure reliable operation of the generators.
- Load flexibility will also be an important aspect of DER integration. Investments made to utilize loads for conventional demand response (reducing load during peak demand period) and grid services will be an important aspect of grid reliability with fewer fossil units available.
- To reach levels of DER integration evaluated in this study, increased visibility and control of DER resources will be important. This can be achieved either directly via centralized communications or control by the grid operator or with third-party aggregators. Investments in aggregation and DER monitoring would allow the system operator could consider expected generation from DER resources to commit and dispatch the system at least in part, based on system needs.
- The distributed battery storage in this analysis was assumed able to provide grid services like fast frequency response (FFR) autonomously. However, in order for the DER to have the capability (headroom) to respond quickly and autonomously when needed, the DER must be operated to maintain a minimum level of power and energy reserves. To augment the reserves from DER, it is also possible to use utility-scale BESS resources with FFR.
- It will be important to manage DER inverter configuration closely to have an accurate record of all DER control settings. This is a critical step for having an accurate model of the grid so it is possible to understand and mitigation challenges that arise.
- It is recommended to have the ability to adjust the response characteristics and protection settings as the grid evolves. The ability to update inverter settings remotely can go a long way toward mitigation “legacy inverter control” settings that are no longer appropriate for a future grid and end up hampering the grids ability to integrate higher levels of renewables.
- As significant levels of DER are integrated, it is recommended to revisit the under-frequency load-shedding scheme to coordinate it with downstream DER, which may be providing support to the grid during disturbances and should avoid being disconnected.
- It is recommended that grid stability analysis for very high penetrations of renewables be conducted with more appropriate models like electromagnetic transient (EMT) simulation models. Note that it is not considered necessary to represent the entire Puerto Rican grid in EMT, but representing reasonable-sized portions will provide tremendous insight to the inverter controls and behaviors that could inform detailed inverter specification documents.
- It is recommended to study emerging inverter technologies like grid-forming inverter technology and its potential benefits for stabilizing a high-renewable inverter-dominant Puerto Rican grid.
- It is recommended to review existing transmission protection schemes to check for schemes like line-distance protection that may be vulnerable to misoperation when high levels of inverter-based resources are present.

9 Key Findings

The results of this study are significant and clearly illustrate that Puerto Rico can radically shift its power system to one that is based on local, renewable, and resilient distributed energy resources. This can be done in a way that improves system reliability, grid stability, and resiliency for Puerto Rico's ratepayers. This transition will yield environmental benefits with reduced CO_2 emissions and other environmental pollutants and will considerably decrease fossil fuel consumption in Puerto Rico. This will make the power system, and the economy, less susceptible to the fuel price volatility of oil markets and more energy independent. In addition, the study results produced the following key findings:

- DER can be used as a tool to accelerate the retirement of Puerto Rico's aging fossil fleet replacing that capacity with more flexible, clean, and resilient technology. The AES coal plant, for example, could be retired by 2024 provided there is enough investment in DERs and energy efficiency.
- As solar integration increases across Puerto Rico it will be spread out across the island. While any individual solar site may have a large amount of variability due to cloud cover, the island-wide variability will be significantly reduced.
- Increased flexibility will be required by the fossil fleet, especially for the CC units, which will be expected to cycle on and offline more often and run for fewer hours per year. This may change the maintenance requirements, cycling costs, and reliability of these generators in the future.
- Renewable curtailment is quite low across all scenarios and is highest (on a relative basis) in the Base Case before any storage is added. Total renewable energy perspective, curtailment is limited to 1% even in the highest DER scenarios.
- Oil and gas both experience more than a 50% decline in consumption by the 75% DER scenario. As a result, Puerto Rico would be less susceptible to fuel price volatility and would become more energy independent with increased DER adoption. This reduction in fuel consumption also translates to a more than 70% reduction (over 6 million tons) in carbon dioxide emissions by the 75% DER case.
- The production cost savings (not accounting for capital cost of new resources) from introducing more DER onto the grid while also retiring fossil fuel-based generation are considerable, with savings range anywhere from roughly $144 million (25% DER) to $703 million per year (75% DER). This equates to an avoided energy cost of $64 to $86/MWh of additional solar energy.
- Another benefit of DER integration is that the resources are sited directly at the loads, reducing the total amount of energy the flows across the transmission network. This yields reliability, resiliency, and avoided transmission loss benefits. Across the scenarios analyzed, DER reduced net flows across the network as each individual region becomes more self-sufficient with the increase in DERs located within that respective region.
- In the 50% DER and 75% DER case there are hours with 100% of generation coming from IBR, even after using storage to shift much of the surplus generation. With current inverter technologies and the absence of synchronous condensers, this level of operation would not be reliable, but changes to operations can be made to ensure reliability if those mitigations are not available.
- DER inverter controls for grid-response is critical to achieving stable grid operation up through the 50% scenario. The use of DER inverter functions like frequency-watt response (FFR) and volt-

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var response that are tuned for fast-response are effective in stabilizing the grid for significant disturbances. About 300MW of FFR is needed to enable the grid to survive generation-loss events through the 50% scenario.

- For very high penetrations of DER, more detailed analytical tools (like electromagnetic transient tools) are needed to assess the stability of the 75% scenario, particularly with higher-fidelity representation of the inverter-based resources.
- Reducing the maximum dispatch of the largest single generating unit, committing addition conventional generators, and utilizing synchronous condensers are effective approaches based on existing technology and traditional practices that can be used to mitigation grid stability challenges for very high penetration scenarios.

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10 Next Steps

The power system evolution evaluated in this study is significant and should not be taken lightly. If implemented, these changes would make Puerto Rico one of the highest inverter-based renewable grids in the world, which industry leading DER integration. While this study was comprehensive, it was not exhaustive. There are unaddressed technical, economic, reliability, and organizational challenges that should be evaluated further. These include, but are not limited to the following:

- Further research should be conducted to better understand the role of forecasting, both for the solar resource and in the way DER is operated more generally. This study did not explicitly consider forecasting of the solar resource or battery utilization. Instead it was assumed that the battery storage additions could effectively manage the uncertainty in the solar resource.
- Further analysis could be conducted to evaluate the role of microgrids to provide both local resiliency benefits and grid benefits. This study did not evaluate specific DER systems or microgrids, but instead evaluated the bulk-system impact on the grid.
- This study assumed aggregated control and visibility of the DER. While this may be appropriate for long-term system planning several years in the future, DER aggregation has, as of yet, not been deployed at scale. Near-term analysis on DER integration should be evaluated to consider challenges of operations prior to aggregated control and visibility.
- Additional study work should be conducted to quantify reliability impacts of retiring generation in the appropriate manner, specifically using resource adequacy methods. The retirements analyzed in this study were selected conservatively but did not rely on detailed retirement and reliability analysis.
- More detailed analysis is required for assessing the stability of grid for inverter-dominant grid operations like those from the 75% renewable scenario. This would include electromagnetic transient (EMT) simulation tools with high-fidelity inverter models to better understand the stability of the grid with today's grid-following inverter technology and the emerging grid-forming inverter technology.
- The development of a DER inverter behavior specification is recommended to clearly define the performance, characteristics, and functions needed to enable a stable and reliable future grid that is reliant on DER.
- A review of existing transmission protection schemes to check for schemes like line-distance protection that may be vulnerable to misoperation when high levels of inverter-based resources are present.

Appendix

Additional Data and Assumptions

Table 17: Calculations of Resilient Homes, DER Capacity, and Renewable Energy by Scenario

Row	Formula	Property	25% DER	50% DER	75% DER
A	Assumed	Renewable Energy as % of Total Load	25%	50%	75%
B	Input Data	Total Number of Homes in Puerto Rico	1,500,000	1,500,000	1,500,000
C	Input Data	Owner Occupied # of Homes	986,165	986,165	986,165
D	Input Data	Active Residential Customers	1,340,652	1,340,652	1,340,652
E	Input Data	Percent of Non Apartment Houses	95%	95%	95%
F	Input Data	Number of Customers with home suitable for Rooftop PV	1,000,000	1,000,000	1,000,000
G	= F / D	Percent of Customers that have a home suitable for Rooftop PV	75%	75%	75%
H	Assumed	Percent of homes with a rooftop PV system by Load Year	50.0%	75.0%	100.0%
I	Assumed	Assumed average rooftop PV size (kW)	2.7	2.7	2.7
J	= (F * H * I) / 1000	Residential Installed rooftop PV (MW)	1,350	2,025	2,700
K	Input Data	NREL SAM Capacity Factor[1]	19.2%	19.2%	19.2%
L	= (J * K * 8760) / 1000	Total Generation of Rooftop PV (GWh)	2,271	3,406	4,541
M	Assumed	Gross Energy Sales before EE (GWh)[2]	15,648	15,648	15,648
N	= M * 25%	Energy Efficiency Assumption (GWh)[3]	3,912	3,912	3,912
O	= M - N	Gross Energy Sales after EE (GWh)	11,736	11,736	11,736
P	= A * O	Renewable Target (GWh)	2,934	5,868	8,802
Q	Input Data	Existing Renewable Generation from UPV and Wind (GWh)	423	423	423
R	= P - L - Q	Additional Renewable Generation from C&I (GWh)[4]	240	2,039	3,838
S	= (R * 8760) / (K * 8760)	Necessary Renewable Buildout from C&I (MW)	143	1,212	2,282
T	= J + S	Total PV Capacity (Residential Rooftop PV + C&I (MW)	1,493	3,237	4,982
U	= (J-172) * 4.5	Storage Buildout for Residential DPV (MWh)[5]	5,301	8,339	11,376

Notes

1. Based on data from NREL Puerto Rico Simulated High Resolution Dataset, National Solar Radiation Database
2. From PREPA IRP, Exhibit 3-11: Gross Energy Demand for Generation
3. Based on Queremos Sol's Energy Efficiency and Conservation Policy Objective of 25% by 2035
4. C&I refers to commercial and industrial customers, as well as carports and repurposed landfills
5. Assumed weighted average of solar PV and battery systems, ranging from 1.8 kW, 4.2 kWh to 4.2 kW, 21.6 kWh systems.
   172 nets out existing rooftop PV from battery calculations

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Table 18: Retirement Priority Ranking

Unit Name	Type	Capacity (MW)	Generation Cost ($/MWh)	FO&M ($/kW-y)	Age (Yrs)	Emissions Rate (ton/MWh)	Flexibility	Forced Outage Rate	Location (0 = North, 1 = South)	Retirement Weight	Retirement Rank
AES 1	Coal	227	40	38.37	19	1.01	5	0.03	1	150	1
AES 2	Coal	227	40	38.37	19	1.01	5	0.03	1	150	2
Palo Seco Steam 3	ST	216	134	46.47	61	0.84	3	0.42	0	147	3
Palo Seco Steam 4	ST	216	134	46.47	60	0.84	3	0.42	0	147	4
Aguirre Steam 2	ST	450	131	32.04	46	0.84	3	0.2	1	140	5
Aguirre Steam 1	ST	450	130	32.04	46	0.83	3	0.2	1	140	6
Aguirre CCGT 1	CC	260	274	22.64	44	0.90	2	0.2	1	132	7
Aguirre CCGT 2	CC	260	274	22.64	44	0.90	2	0.2	1	132	8
Yabucoa GT12	GT	21	365	26.54	50	1.16	1	0.15	**1**	130	9
Yabucoa GT11	GT	21	365	26.54	50	1.16	1	0.15	**1**	130	10
Aguirre GT21	GT	21	365	26.54	49	1.16	1	0.15	1	129	11
Aguirre GT22	GT	21	365	26.54	49	1.16	1	0.15	1	129	12
Costa Sur GT11	GT	21	365	26.54	49	1.16	1	0.15	1	129	13
Costa Sur GT12	GT	21	365	26.54	49	1.16	1	0.15	1	129	14
San Juan Steam 7	ST	100	142	49.02	56	0.91	3	0.15	0	125	15
San Juan Steam 8	ST	100	142	49.02	52	0.91	3	0.15	0	123	16
Costa Sur Steam 6	ST	410	106	35.96	48	0.57	3	0.04	1	122	17
Costa Sur Steam 5	ST	410	106	35.96	49	0.57	3	0.02	1	120	18
Vega Baja GT11	GT	21	365	26.54	50	1.16	1	0.15	**0**	105	19
Vega Baja GT12	GT	21	365	26.54	50	1.16	1	0.15	**0**	105	20
Daguao GT11	GT	21	365	26.54	49	1.16	1	0.15	0	104	21
Daguao GT12	GT	21	365	26.54	49	1.16	1	0.15	0	104	22
Palo Seco GT12	GT	21	365	26.54	49	1.16	1	0.15	0	104	23
Palo Seco GT21	GT	21	365	26.54	49	1.16	1	0.15	0	104	24
Palo Seco GT11	GT	21	365	26.54	49	1.16	1	0.15	0	104	25
Jobos GT11	GT	21	365	26.54	48	1.16	1	0.15	0	104	26
Jobos GT12	GT	21	365	26.54	48	1.16	1	0.15	0	104	27
Palo Seco GT22	GT	21	365	26.54	48	1.16	1	0.15	0	104	28
Palo Seco GT31	GT	21	365	26.54	48	1.16	1	0.15	0	104	29
Palo Seco GT32	GT	21	365	26.54	48	1.16	1	0.15	0	104	30
EcoElectrica	CC	507	81	29.89	22	0.44	2	0.02	1	89	31
Cambalache GT 2	GT	83	159	24.44	44	1.00	1	0.1	0	81	32
Cambalache GT 3	GT	83	159	24.44	44	1.00	1	0.1	0	81	33
San Juan CCGT 6	CC	200	85	27.4	13	0.63	2	0.18	0	77	34
San Juan CCGT 5	CC	200	83	27.4	13	0.61	2	0.18	0	77	35
Mayaguez Plant 1	GT	50	119	26.54	12	0.75	1	0.09	0	60	36
Mayaguez Plant 2	GT	50	119	26.54	12	0.75	1	0.09	0	60	37
Mayaguez Plant 3	GT	50	119	26.54	12	0.75	1	0.09	0	60	38
Mayaguez Plant 4	GT	50	119	26.54	12	0.75	1	0.09	0	60	39

Table 19: Fossil Unit Average Heat Rate Curves

Category	Unit Name	Min Stable Level	Max Capacity	Heat Rate Coeff (ax^2)	Heat Rate Coeff (bx)	Heat Rate Coeff (c)	MW1	MW2	MW3	MW4	MW5	MW6	MW7	AHR1	AHR2	AHR3	AHR4	AHR5	AHR6	AHR7
Coal	AES 1	166	227	0.00896	6177	363	166	176	186	197	207	217	227	9,849	9,814	9,792	9,783	9,783	9,792	9,808
Coal	AES 2	166	227	0.00896	6177	363	166	176	186	197	207	217	227	9,849	9,814	9,792	9,783	9,783	9,792	9,808
CC	Aguirre CCGT 1	46	260	0.02546	-745	1379	46	82	117	153	189	224	260	30,404	18,220	13,995	12,164	11,368	11,114	11,179
CC	Aguirre CCGT 2	46	260	0.02546	-745	1379	46	82	117	153	189	224	260	30,404	18,220	13,995	12,164	11,368	11,114	11,179
CC	EcoElectrica	275	507	0.00879	-501	1810	275	314	352	391	430	468	507	8,496	8,025	7,731	7,563	7,486	7,478	7,523
CC	San Juan CCGT 5	106	200	0.02266	-510	726	106	122	137	153	169	184	200	8,741	8,214	7,889	7,702	7,616	7,605	7,652
CC	San Juan CCGT 6	106	200	0.02333	-525	748	106	122	137	153	169	184	200	9,003	8,460	8,124	7,933	7,844	7,833	7,881
ST	Aguirre Steam 1	143	450	0.00443	6057	705	143	194	245	297	348	399	450	11,618	10,547	10,016	9,747	9,624	9,591	9,617
ST	Aguirre Steam 2	143	450	0.00448	6120	712	143	194	245	297	348	399	450	11,739	10,656	10,121	9,849	9,725	9,691	9,717
ST	Costa Sur Steam 5	131	410	0.00494	6149	652	131	178	224	271	317	364	410	11,773	10,699	10,166	9,895	9,771	9,738	9,764
ST	Costa Sur Steam 6	131	410	0.00494	6149	652	131	178	224	271	317	364	410	11,773	10,699	10,166	9,895	9,771	9,738	9,764
ST	Palo Seco Steam 3	69	216	0.00935	6135	343	69	94	118	143	167	192	216	11,747	10,675	10,143	9,873	9,749	9,716	9,742
ST	Palo Seco Steam 4	69	216	0.00935	6135	343	69	94	118	143	167	192	216	11,747	10,675	10,143	9,873	9,749	9,716	9,742
ST	San Juan Steam 7	32	100	0.02180	6622	171	32	43	55	66	77	89	100	12,671	11,519	10,947	10,656	10,523	10,487	10,515
ST	San Juan Steam 8	32	100	0.02170	6590	170	32	43	55	66	77	89	100	12,609	11,462	10,893	10,603	10,471	10,435	10,463
GT	Aguirre GT21	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
GT	Aguirre GT22	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
GT	Cambalache GT 2	50	83	0.00118	8967	206	50	56	61	67	72	78	83	13,150	12,748	12,419	12,146	11,916	11,719	11,549
GT	Cambalache GT 3	50	83	0.00118	8967	206	50	56	61	67	72	78	83	13,150	12,748	12,419	12,146	11,916	11,719	11,549
GT	Costa Sur GT11	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
GT	Costa Sur GT12	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
GT	Daguao GT11	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
GT	Daguao GT12	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
GT	Jobos GT11	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
GT	Jobos GT12	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
GT	Mayaguez Plant 1	25	50	0.00158	7236	100	25	29	33	38	42	46	50	11,286	10,719	10,296	9,969	9,708	9,496	9,320
GT	Mayaguez Plant 2	25	50	0.00158	7236	100	25	29	33	38	42	46	50	11,286	10,719	10,296	9,969	9,708	9,496	9,320
GT	Mayaguez Plant 3	25	50	0.00158	7236	100	25	29	33	38	42	46	50	11,286	10,719	10,296	9,969	9,708	9,496	9,320
GT	Mayaguez Plant 4	25	50	0.00158	7236	100	25	29	33	38	42	46	50	11,286	10,719	10,296	9,969	9,708	9,496	9,320
GT	Palo Seco GT11	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
GT	Palo Seco GT12	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
GT	Palo Seco GT21	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
GT	Palo Seco GT22	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
GT	Palo Seco GT31	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
GT	Palo Seco GT32	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
GT	Vega Baja GT11	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
GT	Vega Baja GT12	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
GT	Yabucoa GT11	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
GT	Yabucoa GT12	13	21	0.00580	11180	65	13	14	16	17	18	20	21	16,260	15,802	15,424	15,106	14,835	14,602	14,400
Other	Landfill Gas	2	4	0.03047	11180	12	2	2	3	3	3	4	4	17,437	16,562	15,908	15,402	14,999	14,671	14,400

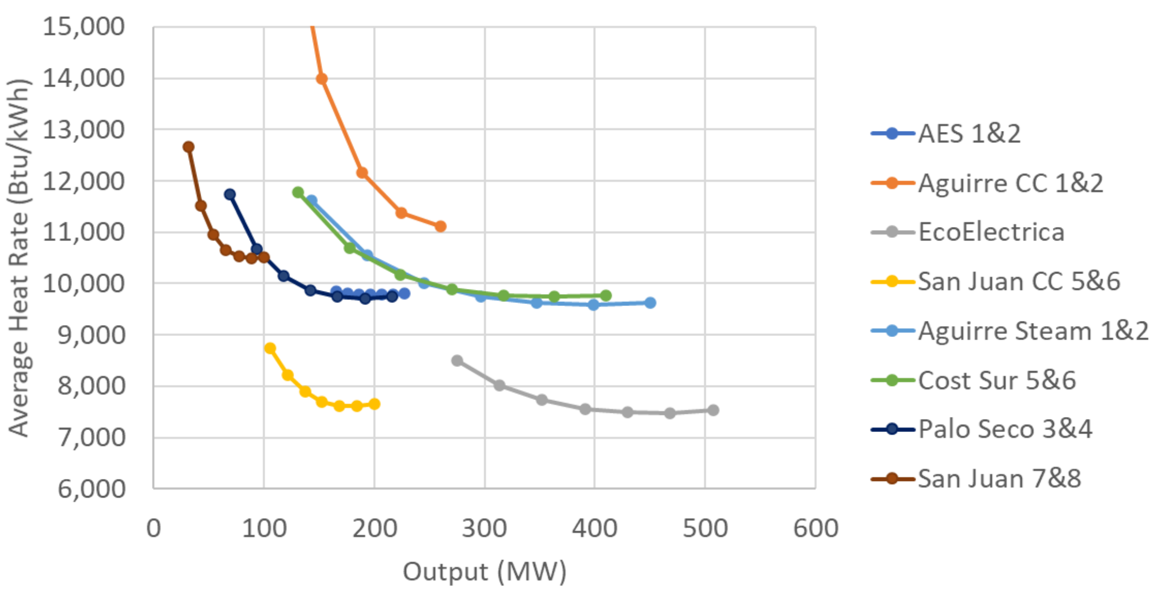

Figure 63: Fossil Unit Average Heat Rate Curves

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Table 20: DER Capacity by Region, Customer Class, and Scenario

	DPV Capacity (MW)			Battery Capacity (MWh)		
	25% DER	50% DER	75% DER	25% DER	50% DER	75% DER
Residential	**1,350**	**2,025**	**2,700**	**5,301**	**8,339**	**11,376**
Arecibo	145	211	277	517	815	1,112
Bayamón	251	378	504	994	1,562	2,133
Caguas	221	331	440	860	1,350	1,841
Carolina	162	246	329	656	1,035	1,409
Mayagüez	152	227	302	590	923	1,260
Ponce ES	62	88	114	206	324	446
Ponce OE	118	176	234	459	720	981
San Juan	239	369	499	1,021	1,611	2,196
Commercial	**143**	**1,212**	**2,282**	**0**	**0**	**0**
Arecibo	12	102	191	0	0	0
Bayamón	12	106	199	0	0	0
Caguas	19	162	304	0	0	0
Carolina	13	110	207	0	0	0
Mayagüez	21	181	341	0	0	0
Ponce ES	5	41	76	0	0	0
Ponce OE	8	68	129	0	0	0
San Juan	52	443	834	0	0	0
Total	**1,493**	**3,237**	**4,982**	**5,301**	**8,339**	**11,376**
Arecibo	157	312	468	517	815	1,112
Bayamón	264	483	703	994	1,562	2,133
Caguas	240	492	744	860	1,350	1,841
Carolina	175	356	536	656	1,035	1,409
Mayagüez	174	408	643	590	923	1,260
Ponce ES	67	129	191	206	324	446
Ponce OE	126	245	363	459	720	981
San Juan	291	812	1,333	1,021	1,611	2,196

*Includes existing distributed rooftop PV

Table 21: Dynamic Load Model Parameters for PSSE CMLDBU Model

CON	Description	Param Set 1	Param Set 2	Param Set 3	Param Set 4
J+0	LOAD MVA BASE	-1	-1	-1	-1
J+1	SUBSTATION SHUNT B (PU OF MVA BASE)	0	0	0	0
J+2	Rfdr - Feeder R (pu of Load MVA base)	0.04	0.02	0.03	0.05
J+3	Xfdr - Feeder X (pu of Load MVA base)	0.04	0.02	0.03	0.05
J+4	Fb - Fraction of Feeder Compn at substation end	0.75	0.75	0.75	0.75

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J+5	Xxf - Transformer Reactance - pu of load MVA base	0.08	0.08	0.08	0.08
J+6	Tfixhs - High side fixed transformer tap	1	1	1	1
J+7	Tfixls - Low side fixed transformer tap	1	1	1	1
J+8	LTC - LTC flag (1=active, 0=inactive)	0	0	0	0
J+9	Tmin - LTC min tap (on low side)	0.9	0.9	0.9	0.9
J+10	Tmax - LTC max tap (on low side)	1.1	1.1	1.1	1.1
J+11	Step - LTC Tstep (on low side)	0.0063	0.0063	0.0063	0.0063
J+12	Vmin - LTC Vmin tap (low side pu)	1.025	1.025	1.025	1.025
J+13	Vmax - LTC Vmax tap (low side pu)	1.04	1.04	1.04	1.04
J+14	TD - LTC Control time delay (sec)	30	30	30	30
J+15	TC - LTC Tap adjustment time delay (sec)	5	5	5	5
J+16	Rcmp - LTC Rcomp (pu of load MVA base)	0	0	0	0
J+17	Xcmp - LTC Xcomp (pu of load MVA base)	0	0	0	0
J+18	FmA - Motor A Fraction	0.201	0.221	0.201	0.221
J+19	FmB - Motor B Fraction	0.146	0.162	0.146	0.162
J+20	FmC - Motor C Fraction	0.064	0.062	0.064	0.062
J+21	FmD - Motor D Fraction	0.151	0.249	0.151	0.249
J+22	Fel - Electronic Device Fraction	0.145	0.108	0.145	0.108
J+23	PFel - PF of Electronic Load	1	1	1	1
J+24	Vd1 - Voltage at which electronic loads start to drop	0.7	0.7	0.7	0.7
J+25	Vd2 - Voltage at which all electronic load have dropped	0.5	0.5	0.5	0.5
J+26	PFs - Static Load Power Factor	-0.997	-0.997	-0.997	-0.997
J+27	P1e - P1 exponent	2	2	2	2
J+28	P1c - P1 coefficient	0.485	0.311	0.485	0.311
J+29	P2e - P2 exponent	1	1	1	1
J+30	P2c - P2 coefficient	0.515	0.689	0.515	0.689
J+31	Pfrq - Frequency sensitivity	0	0	0	0
J+32	Q1e - Q1 exponent	2	2	2	2
J+33	Q1c - Q1 coefficient	-0.5	-0.5	-0.5	-0.5
J+34	Q2e - Q2 exponent	1	1	1	1
J+35	Q2c - Q2 coefficient	1.5	1.5	1.5	1.5
J+36	Qfrq - Frequency sensitivity	-1	-1	-1	-1
J+37	MtypA - Motor type	3	3	3	3
J+38	LFmA - Loading factor (MW/MVA rating)	0.75	0.75	0.75	0.75
J+39	RaA - Stator resistance	0.04	0.04	0.04	0.04
J+40	LsA - Synchronous reactance	1.8	1.8	1.8	1.8
J+41	LpA - Transient reactance	0.12	0.12	0.12	0.12
J+42	LppA - Sub-transient reactance	0.104	0.104	0.104	0.104
J+43	TpoA - Transient open circuit time constant	0.095	0.095	0.095	0.095

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J+44	TppoA - Sub-transient open circuit time constant	0.0021	0.0021	0.0021	0.0021
J+45	HA - Inertia constant	0.1	0.2	0.2	0.1
J+46	etrqA - Torque speed exponent	0	0	0	0
J+47	Vtr1A - U/V trip1 V (pu)	0.7	0.75	0.65	0.7
J+48	Ttr1A - U/V trip1 time (sec)	0.02	0.02	0.02	0.02
J+49	Ftr1A - U/V trip1 fraction	0.2	0.2	0.2	0.2
J+50	Vrc1A - U/V trip1 reclose V (pu)	1	1	1	1
J+51	Trc1A - U/V trip1 reclose time (sec)	99999	99999	99999	99999
J+52	Vtr2A - U/V trip2 V (pu)	0.5	0.6	0.55	0.45
J+53	Ttr2A - U/V trip2 time (sec)	0.02	0.02	0.02	0.02
J+54	Ftr2A - U/V trip2 fraction	0.7	0.7	0.7	0.7
J+55	Vrc2A - U/V trip2 reclose V (pu)	0.7	0.78	0.75	0.65
J+56	Trc2A - U/V trip2 reclose time (sec)	0.1	0.08	0.12	0.16
J+57	MtypB - Motor type	3	3	3	3
J+58	LFmB - Loading factor (MW/MVA rating)	0.75	0.75	0.75	0.75
J+59	RaB - Stator resistance	0.03	0.03	0.03	0.03
J+60	LsB - Synchronous reactance	1.8	1.8	1.8	1.8
J+61	LpB - Transient reactance	0.19	0.19	0.19	0.19
J+62	LppB - Sub-transient reactance	0.14	0.14	0.14	0.14
J+63	TpoB - Transient open circuit time constant	0.2	0.2	0.2	0.2
J+64	TppoB - Sub-transient open circuit time constant	0.0026	0.0026	0.0026	0.0026
J+65	HB - Inertia constant	0.5	0.3	0.4	0.4
J+66	etrqB - Torque speed exponent	2	2	2	2
J+67	Vtr1B - U/V trip1 V (pu)	0.6	0.5	0.65	0.7
J+68	Ttr1B - U/V trip1 time (sec)	0.02	0.02	0.02	0.02
J+69	Ftr1B - U/V trip1 fraction	0.2	0.2	0.2	0.2
J+70	Vrc1B - U/V trip1 reclose V (pu)	0.75	0.8	0.7	0.75
J+71	Trc1B - U/V trip1 reclose time (sec)	0.05	0.05	0.1	0.15
J+72	Vtr2B - U/V trip2 V (pu)	0.5	0.6	0.55	0.65
J+73	Ttr2B - U/V trip2 time (sec)	0.02	0.02	0.02	0.02
J+74	Ftr2B - U/V trip2 fraction	0.3	0.3	0.3	0.3
J+75	Vrc2B - U/V trip2 reclose V (pu)	0.65	0.75	0.7	0.8
J+76	Trc2B - U/V trip2 reclose time (sec)	0.05	0.1	0.08	0.15
J+77	MtypC - Motor type	3	3	3	3
J+78	LFmC - Loading factor (MW/MVA rating)	0.75	0.75	0.75	0.75
J+79	RaC - Stator resistance	0.03	0.03	0.03	0.03
J+80	LsC - Synchronous reactance	1.8	1.8	1.8	1.8
J+81	LpC - Transient reactance	0.19	0.19	0.19	0.19
J+82	LppC - Sub-transient reactance	0.14	0.14	0.14	0.14

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J+83	TpoC - Transient open circuit time constant	0.2	0.2	0.2	0.2
J+84	TppoC - Sub-transient open circuit time constant	0.0026	0.0026	0.0026	0.0026
J+85	HC - Inertia constant	0.1	0.2	0.15	0.2
J+86	etrqC - Torque speed exponent	2	2	2	2
J+87	Vtr1C - U/V trip1 V (pu)	0.65	0.6	0.55	0.65
J+88	Ttr1C - U/V trip1 time (sec)	0.02	0.02	0.02	0.02
J+89	Ftr1C - U/V trip1 fraction	0.2	0.2	0.2	0.2
J+90	Vrc1C - U/V trip1 reclose V (pu)	1	1	1	1
J+91	Trc1C - U/V trip1 reclose time (sec)	9999	9999	9999	9999
J+92	Vtr2C - U/V trip2 V (pu)	0.5	0.6	0.55	0.55
J+93	Ttr2C - U/V trip2 time (sec)	0.02	0.02	0.02	0.02
J+94	Ftr2C - U/V trip2 fraction	0.3	0.3	0.3	0.3
J+95	Vrc2C - U/V trip2 reclose V (pu)	0.65	0.75	0.7	0.7
J+96	Trc2C - U/V trip2 reclose time (sec)	0.1	0.08	0.16	0.12
J+97	Tstall - Stall dealy (sec)	9999	9999	9999	9999
J+98	Trestart - Restart delay (sec)	0.3	0.5	0.4	0.6
J+99	Tv - Voltage input time constant(sec)	0.02	0.02	0.02	0.02
J+100	Tf - Frequency input time constant(sec)	0.05	0.05	0.05	0.05
J+101	CompLF - Compressor load factor, p.u. of rated power	1	1	1	1
J+102	CompPF - Compressor power factor at 1.0 p.u. voltage	0.98	0.98	0.98	0.98
J+103	Vstall - Compressor stall voltage at base condition (p.u.)	0.52	0.52	0.52	0.52
J+104	Rstall - Compressor motor res. with 1.0 p.u. current	0.1	0.1	0.1	0.1
J+105	Xstall - Compressor motor stall reactance - unsat.	0.1	0.1	0.1	0.1
J+106	LFadj - Load factor adjustment to stall voltage	0	0	0	0
J+107	Kp1 - Real power constant for running state 1	0	0	0	0
J+108	Np1 - Real power exponent for running state 1	1	1	1	1
J+109	Kq1 - Reactive power constant for running state 1	6	6	6	6
J+110	Nq1 - Reactive power exponent for running state 1	2	2	2	2
J+111	Kp2 - Real power constant for running state 2	12	12	12	12
J+112	Np2 - Real power exponent for running state 2	3.2	3.2	3.2	3.2
J+113	Kq2 - Reactive power constant for running state 2	11	11	11	11
J+114	Nq2 - Reactive power exponent for running state 2	2.5	2.5	2.5	2.5
J+115	Vbrk - Compressor motor "break-down" voltage (p.u.)	0.86	0.82	0.8	0.84

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J+116	Frst - Fraction of motors capable of restart	0.2	0.2	0.2	0.2
J+117	Vrst - Voltage at which motors can restart (p.u.)	0.95	0.93	0.97	0.94
J+118	CmpKpf - Real power constant for frequency dependency	1	1	1	1
J+119	CmpKqf - Reactive power constant for frequency dependency	-3.3	-3.3	-3.3	-3.3
J+120	Vc1off - Voltage 1 at which contactors start dropping out (p.u.)	0.5	0.6	0.65	0.55
J+121	Vc2off - Voltage 2 at which all contactors drop out (p.u.)	0.4	0.45	0.5	0.4
J+122	Vc1on - Voltage 1 at which all contactors reclose (p.u.)	0.6	0.7	0.75	0.65
J+123	Vc2on - Voltage 2 at which contactors start reclosing (p.u.)	0.5	0.55	0.6	0.5
J+124	Tth - Compressor motor heating time constant(sec)	15	20	10	18
J+125	Th1t - Temperature at which compressor motor begin tripping	0.7	0.7	0.7	0.7
J+126	Th2t - Temperature at which compressor all motors are tripped	1.9	1.9	1.9	1.9
J+127	Fuvr - Fraction of compressor motors with undervoltage relays	0.1	0.1	0.1	0.1
J+128	UVtr1 - 1st voltage pick-up (p.u.)	0.6	0.5	0.55	0.65
J+129	Ttr1 - 1st definite time voltage pick-up (sec)	0.02	0.04	0.03	0.02
J+130	UVtr2 - 2nd voltage pick-up (p.u.)	0	0	0	0
J+131	Ttr2 - 2nd definite time voltage pick-up (sec)	9999	9999	9999	9999

Additional Results and Figures

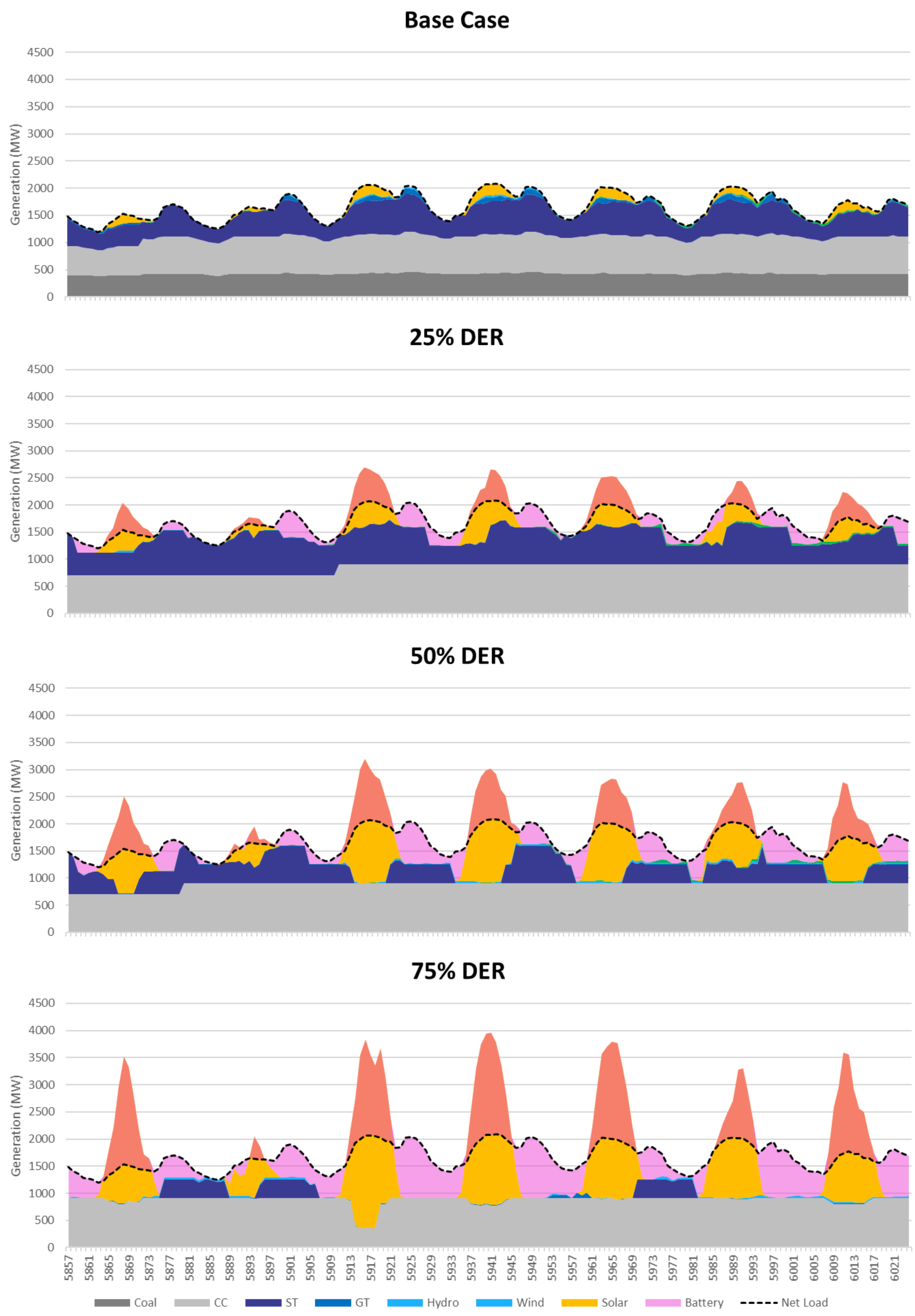

Figure 64: Dispatch Diagram, Minimum Renewables Generation (Sept 2)

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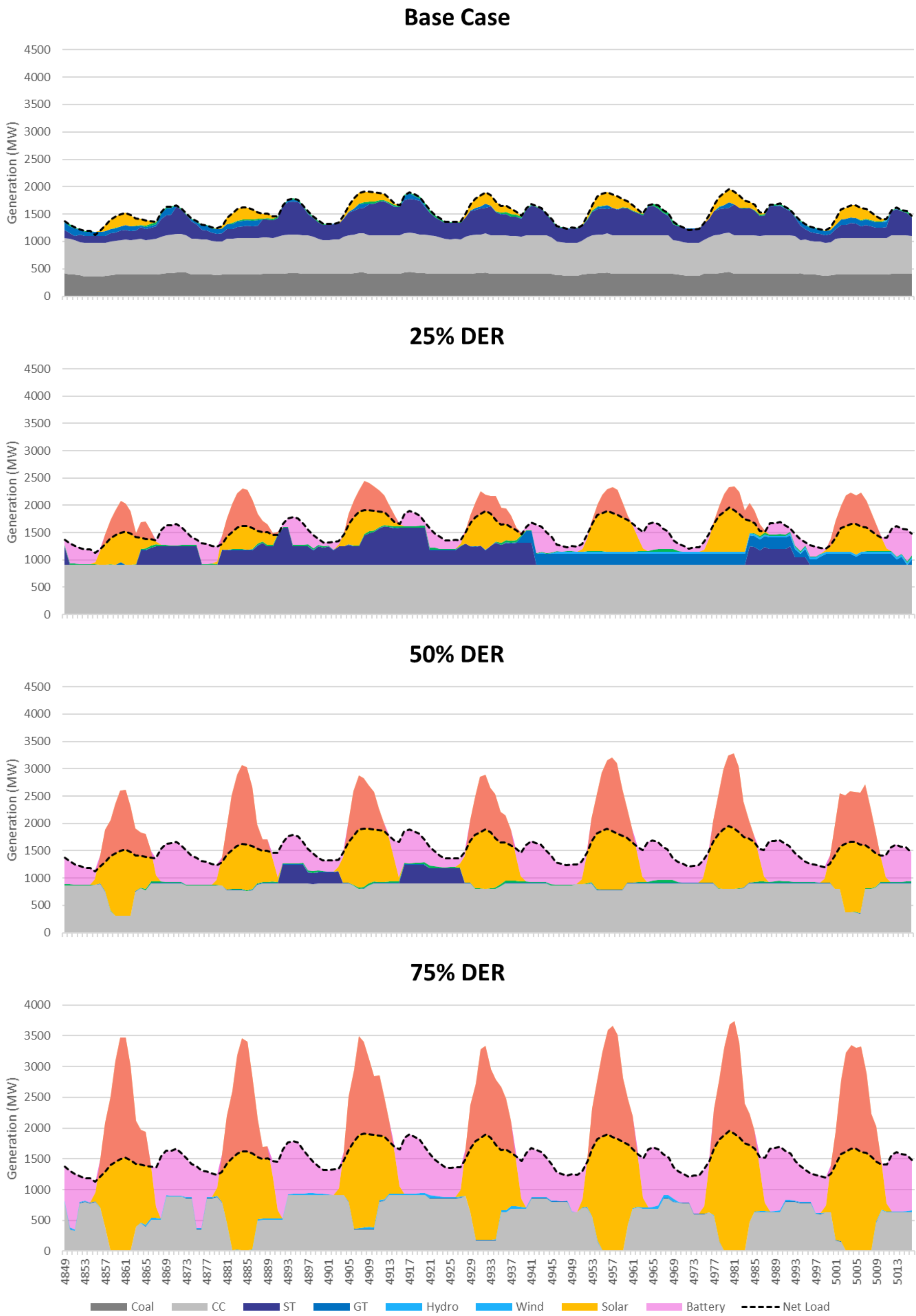

Figure 65: Dispatch Diagram, Representative Average Week (July 22)

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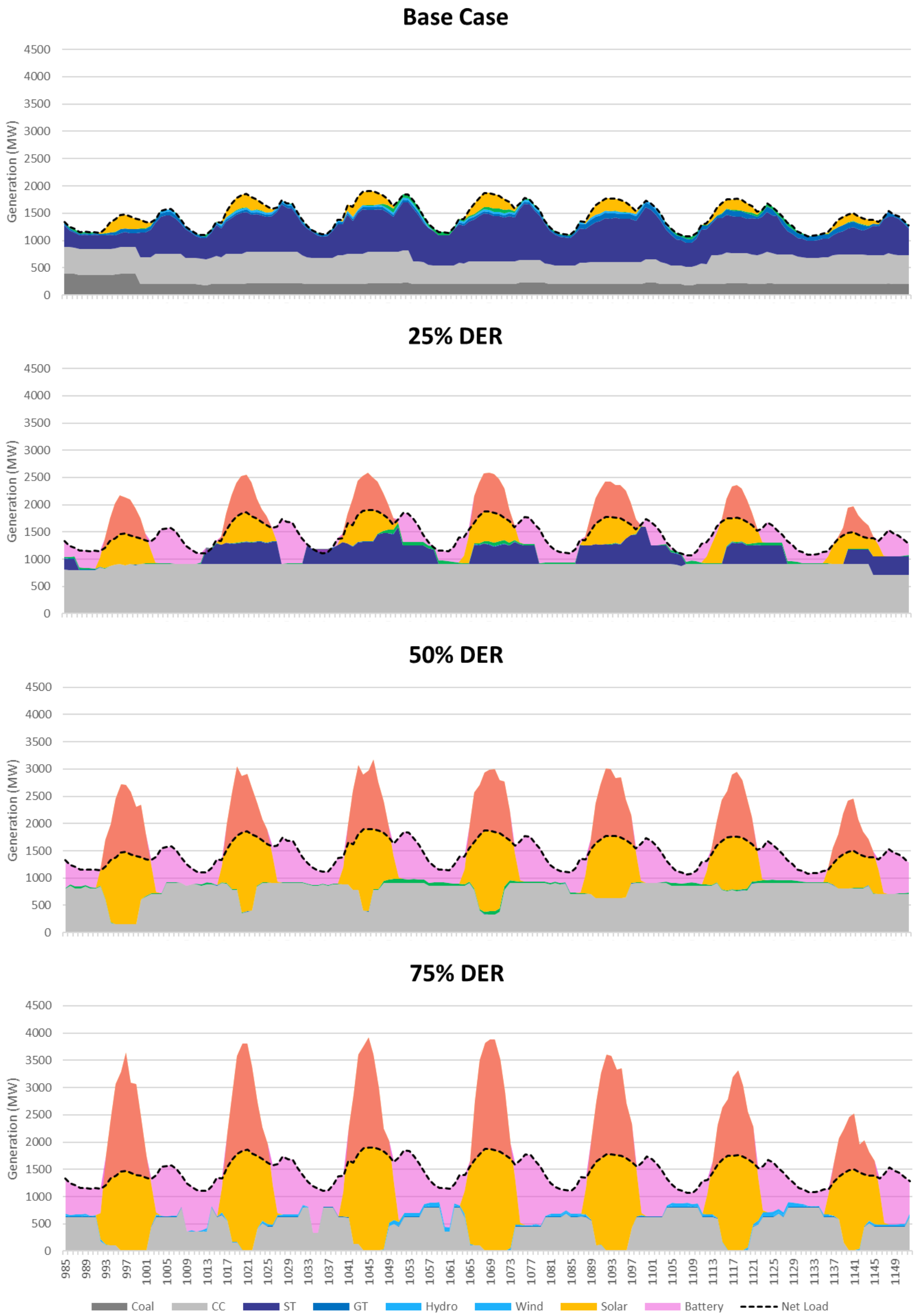

Figure 66: Dispatch Diagram, Minimum Demand (Feb 11)

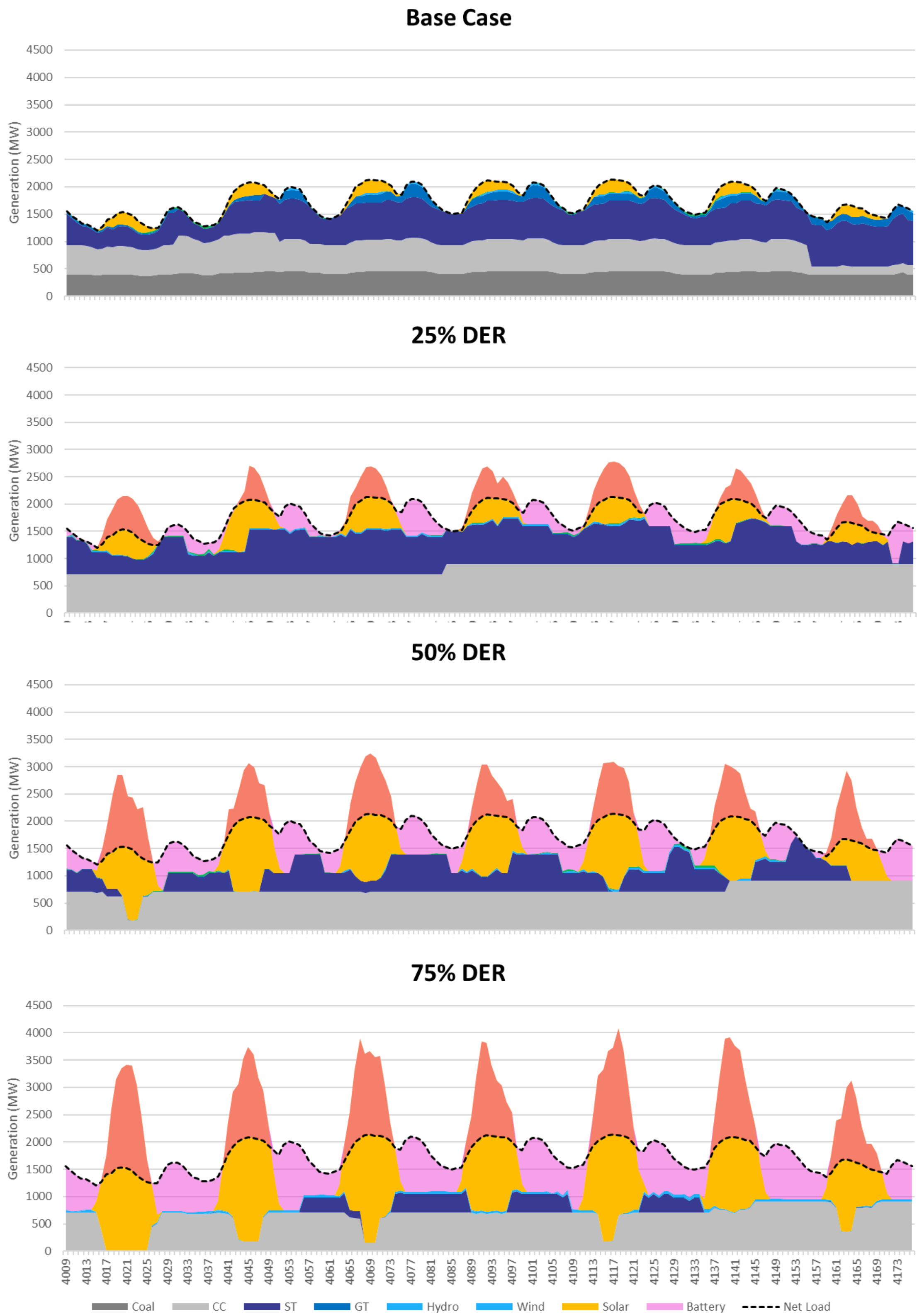

Figure 67: Dispatch Diagram, High Demand Period (June 17)

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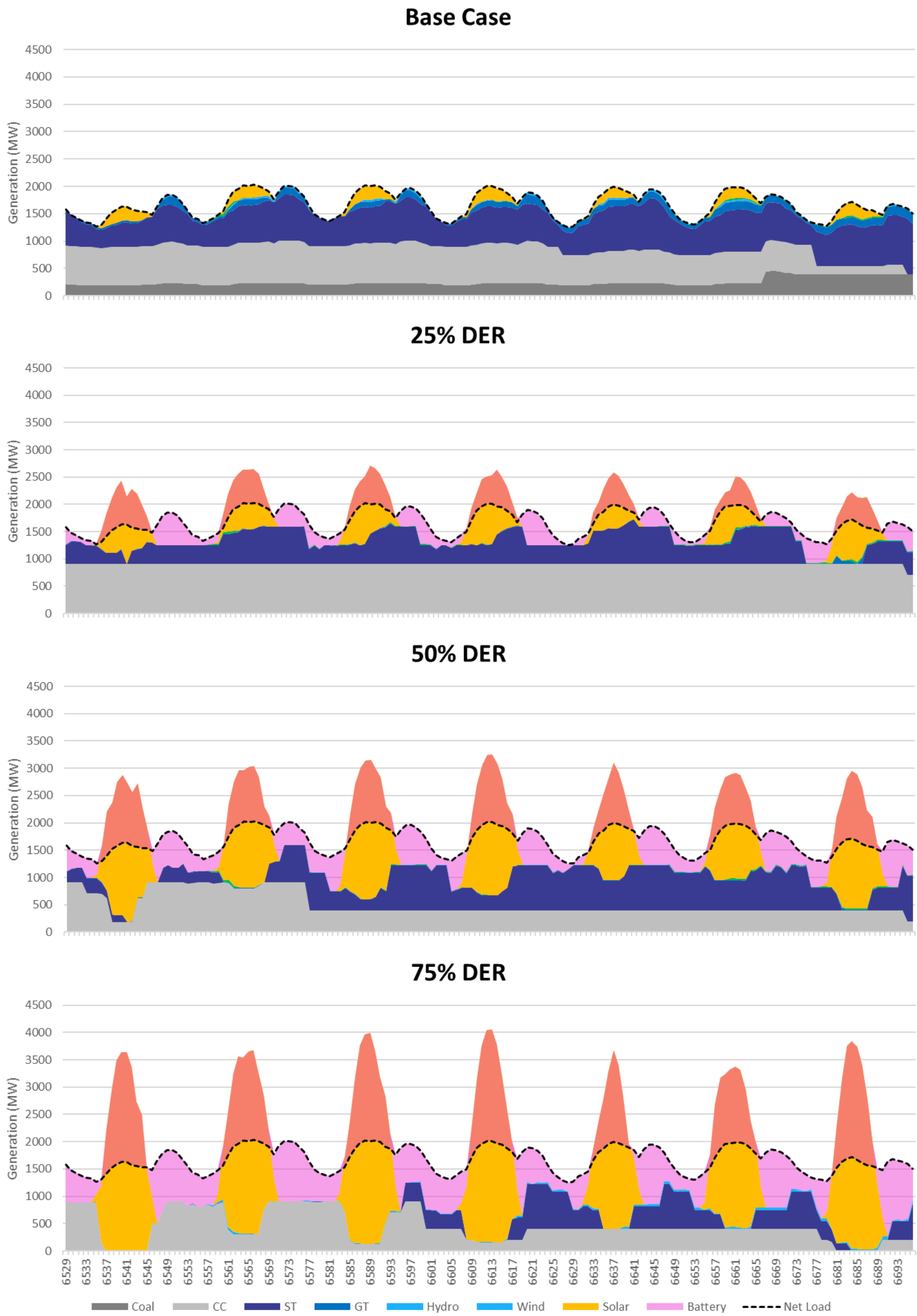

Figure 68: Dispatch Diagram, High Renewables Generation (Sept 30)

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Table 22: Annual Fuel Consumption and Emissions

		Base Case	25% DER	50% DER	75% DER
Consumption (MMBtu)	Coal	30,095,500	-	-	-
	Oil	28,868,900	24,086,510	19,235,470	12,613,700
	Gas	58,462,330	65,887,810	44,084,710	27,454,930
Consumption (fuel type units)	Coal (short tons)	1,544,151	-	-	-
	Oil (bbls)	4,884,857	4,146,285	3,326,911	2,182,950
	Gas (BCF)	58.46	65.89	44.08	27.45
Carbon Dioxide Emissions (tons)	Coal	3,095,319	-	-	-
	Oil	1,916,469	1,454,400	1,129,674	738,118
	Gas	3,420,044	3,854,435	2,578,960	1,606,115
	Total	8,431,833	5,308,834	3,708,634	2,344,233
Change from Base Case					
Consumption (MMBtu)	Coal		(30,095,500)	(30,095,500)	(30,095,500)
	Oil		(4,782,390)	(9,633,430)	(16,255,200)
	Gas		7,425,480	(14,377,620)	(31,007,400)
Consumption (fuel type units)	Coal (short tons)		(1,544,151)	(1,544,151)	(1,544,151)
	Oil (bbls)		(738,572)	(1,557,946)	(2,701,907)
	Gas (BCF)		7	(14)	(31)
Carbon Dioxide Emissions (tons)	Coal		(3,095,319)	(3,095,319)	(3,095,319)
	Oil		(462,069)	(786,795)	(1,178,351)
	Gas		434,391	(841,085)	(1,813,929)
	Total		(3,122,998)	(4,723,199)	(6,087,600)
Percent Change from Base Case					
Consumption (MMBtu)	Coal		-100%	-100%	-100%
	Oil		-17%	-33%	-56%
	Gas		13%	-25%	-53%
Consumption (fuel type units)	Coal (short tons)		-100%	-100%	-100%
	Oil (bbls)		-15%	-32%	-55%
	Gas (BCF)		13%	-25%	-53%
Carbon Dioxide Emissions (tons)	Coal		-100%	-100%	-100%
	Oil		-24%	-41%	-61%
	Gas		13%	-25%	-53%
	Total		-37%	-56%	-72%

Title: ***Puerto Rico Distribution Modeling***

Synopsis: *Summary of Results of modeling of high penetrations of distributed photovoltaic / battery energy storage systems in the Puerto Rican Distribution System.*

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Date: *2021-03-08*

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Table I-1 – Revision History

Date	Revision No.	Description
12/15/2020	01	Initial Revision for Review
01/05/2021	02	Revised per Review Comments
02/08/2021	03	Revised per Review Comments

Table I-2 – Table of Figures

Table I-3 – List of Abbreviations

Abbreviation	***Definition***
AAAC	All Aluminum Alloy Conductor
ACSR	Aluminum Conductor Steel Reinforced
AL	Aluminum
ANSI	American National Standards Institute
AWG	American Wire Gauge
BESS	Battery Energy Storage System
CU	Copper
DER	Distribution Energy Resource
EPR	Ethylene Propylene Rubber
EPRI	Electric Power Research Institute
ESRI	Environmental Systems Research Institute
GIS	Geographic Information System
HD	Hard Drawn
IEEE	Institute of Electrical and Electronic Engineers
LTC	Load Tap Changer
PREPA	Puerto Rico Electrical Power Authority
PSS/e	Power System Simulator for Engineering
PV	Photovoltaic / Photovoltaic System
SOW	Scope of Work
URD	Underground Residential Distribution
VAR	Volt Ampere Reactive
XLP	Cross-linked Polyethylene (insulation)

I. Executive Summary

In cooperation with Cambio PR, Telos Energy and the Energy Futures Group, EE Plus has performed a comprehensive analysis of the impact of high penetrations of highly distributed DER facilities on the Puerto Rico distribution system. This analysis contemplated four analytical scenarios, aligned with analyses performed by Telos Energy on the generation and transmission system. The four scenarios included:

- Base Case scenario, including Photovoltaic (PV) systems and Battery Energy Storage Systems (BESS) currently installed and approved for operation on the distribution system;
- 25% Penetration Scenario, including existing systems and 50% resilient homes, with approximately 1500 MW of PV and BESS systems;
- 50% Penetration Scenario, including existing systems and 75% resilient homes, with approximately 3200 MW of PV and BESS systems; and
- 75% Penetration Scenario, including existing systems and 100% resilient homes, with approximately 5000 MW of PV and BESS systems.

The analyses included the construction of distribution models of approximately 90% of the Puerto Rico Electric Power Authority (PREPA) system within the OpenDSS distribution modelling software. Models were developed based on:

- Distribution GIS data provided by PREPA;
- 7 representative Distribution models in Synergi;
- Annual PV dispatch data provided by the Plexos modelling performed by Telos Energy;
- Annual regional load data provided by the Plexos modelling performed by Telos Energy;
- System impedance and bus loading allocation provided by the PSS/e modelling performed by Telos Energy; and
- Industry and PREPA distribution standards.

The assumptions and methodologies applied to these analyses are documented within this report, and have been coordinated throughout the analytical process with all participating entities. Additional more detailed analyses, with greater granularity, are provided in Volume II of this report, and the data files that support the analyses are included in Volume III of the report.

Although data used was provided by PREPA the model has been independently developed by

EEPlus on behalf of CAMBIO PR and in no way represents any proposal, projection or representation of the Puerto Rico Electric Power Authority.

The results of the analysis indicate that on a steady state basis, the Puerto Rico distribution system can support high levels of distribution penetration, if deployed as envisioned by Cambio and the Queremos Sol group. The deployment will require infrastructure improvements within the distribution system throughout the island. The magnitude of the infrastructure is obviously contingent upon the scenario considered, but even at the highest penetration levels, only approximately 2,525 lines miles of distribution improvement may be required. It is important to note that these results are constrained by both the assumptions detailed herein and the accuracy of the GIS data provided by PREPA. To the extent that these factors are changed, the results may be impacted.

These results are both encouraging and somewhat more favorable in terms of both scope and projected cost than were initially anticipated. Prior experience with the analysis of larger, lumped PV / BESS applied to distribution systems had yielded much higher levels of infrastructure improvement necessary to support deployment. Similar results were anticipated for these analyses. However, owing to two key factors, EE Plus analyses yielded only modest need for infrastructure improvement. The first of these factors is the highly distributed, “behind the meter” nature of the DER contemplated by the proposed deployment. By placing the generation effectively at the load point, the use of the distribution system was minimized. This mitigated both thermal and voltage rise impacts that are common in larger, lumped installations.

The second factor was the coordinated deployment of the PV and BESS systems. By using the PV system to charge the BESS system during peak production conditions, the impacts on system voltage were minimized. Likewise, the use of relatively small individual systems that largely displace local load rather than export excess energy to other loads within the distribution system mitigates any thermal issues.

While certainly favorable, the results of these analyses are not necessarily definitive in the sense that there are multiple, real world considerations that must be factored into actual deployment planning. The ability of the grid to sustain a largely inverter driven system, without significant rotational inertia is questionable. Please reference the Telos report for further details on this issue. Likewise, the ability to defeat the anti-islanding features that are standard in small scale PV inverter systems must be considered to provide a reliability / resiliency benefit to individual consumers. Anti-islanding provisions are typically built into modern inverter systems to prevent inappropriate or unwanted backfeed into the distribution system when the grid is unavailable. To provide reliability benefits for individual customers, this feature must be disabled or otherwise defeated so that the PV / BESS system may serve the individual household loads. Finally, this set of analyses only considered steady state analysis. The impacts on protection systems were not considered, nor were the harmonic impacts associated with this level of inverter penetration. Both of these issues deserve further review. With that said, this novel and forward-looking approach to renewable deployment certainly seems feasible, particularly in light of the rapid advancement of inverter technologies.

II. Scope of Work

The Scope of Work (SOW) for the project has evolved somewhat from the original proposal, predicated on the availability of data from the Puerto Rico Electric Power Authority (PREPA). As originally envisioned, the project contemplated the use of native Synergi distribution models provided by PREPA. However, PREPA provided only seven representative distribution models, less than one percent of the total distribution plant within the system. EE Plus did not believe that an accurate extrapolation of system performance could be made from a sample this small, and as such sought to develop alternate models from other available data.

To that end, EE Plus chose to use the data provided in the PREPA Geographic Information System (GIS) to build new models in OpenDSS, an open-source distribution modeling software developed and distributed by the Electric Power Research Institute (EPRI). Using the approach, EE Plus was able to model approximately 90% of the PREPA distribution system, providing a much better representation of the impacts of high penetrations of PV and battery energy storage systems.

Based on this analytical approach, EE Plus performed the following distribution analysis and remediation planning based on 4 distinct scenarios, intended to align with the transmission and sub-transmission analysis scenarios. The scenarios included:

- Scenario 0: PREPA base case, in accordance with the PREPA Integrated Resource Plan
- Scenario 1: 25% aggregate renewable energy by 2035, with 50% of residences with combined rooftop solar and batteries.
- Scenario 2: 50% aggregate renewable energy by 2035, with 75% of residences with combined rooftop solar and batteries.
- Scenario 3: 75% aggregate renewable energy by 2035, with 100% of residences with combined rooftop solar and batteries.

The analyses performed for the SOW included:

- Evaluation of voltage profile of each feeder, evaluated against ANSI / IEEE criteria;

- Evaluation of thermal performance of each feeder, evaluated against conductor and device ampacities;
- Evaluation of the thermal performance of each substation transformer, based on the published rating of the transformer; and
- Remediation analysis of any violations based on the remediation necessary to support Scenario 3. Remediation included the upgrade of conductors necessary to mitigate voltage or thermal violations at the existing operating voltage of the feeder.

The assumptions, techniques, methodology and evaluation criteria used for these analyses are delineated in subsequent sections.

III. Assumptions

While the information contained in the PREPA GIS was reasonably comprehensive for the purposes of this analysis, there were a number of analytical assumptions that were necessary to fill in gaps and incomplete data in the GIS. The remainder of assumptions used in the analyses were based on published standards and drawings from PREPA.

A. Data Correction / Completion

There were multiple ESRI shapefiles provided as part of the GIS data from PREPA. These included:

- Primary Conductor
- Bus
- Primary Node
- Regulator
- Capacitor Bank
- Transformer Bank
- Switch
- Step Transformer and
- Distributed Generator
- Booster
- Fuse

Most of these required some degree of correction or completion for at least some of the feeders. The assumptions used to correct deficiencies in the GIS data are as follow:

- Where primary conductor voltage was in error or in question, the conductor inherited its operating voltage from the feeder operating voltage;

- Phase rotation was not taken into account. Phasing was considered for topology and connectivity purposes. All three phase lines were modeled as “ABCN”. All two phase lines were modeled as either “ABN”, “ACN", or “BCN”. All single phase lines were modeled as either “AN”, “BN”, or “CN”, with “N” representing the grounded neutral.
- Where the upstream or downstream termination node of a primary conductor segment was not identified, the line was connected to the geospatially closest node of the same feeder, or treated as a “end of line” node, if there was no adjacent conductor of the same feeder
- If the conductor size was not identified, the size was inherited from the upstream conductor. If the inheritance methodology did not work, overhead conductors were set to #2 ACSR, and underground conductors were set to #2 Copper XLP cable.
- Only capacitor banks with a status of “Closed” were modeled.
- Phase rotation was not taken into account. Phasing was considered for topology and connectivity purposes. All three phase capacitors were modeled as “ABCN”. All two phase capacitors were modeled as either “ABN”, “ACN", or “BCN”. All single phase capacitors were modeled as either “AN”, “BN”, or “CN”, with “N” representing the grounded neutral.
- As most capacitors were missing their size kVAR size, capacitors were set to 100 kVAR / can multiplied by the number cans listed. If neither were available, capacitor banks were set to a nominal size of 300 kVAR.
- For voltage regulators, if the connectivity could not be discerned from the feeder topology, the regulator was <u>not</u> modeled.
- Only regulators with a status of “Closed” were modeled.
- All reclosers were assumed to have a continuous current rating of 630 A. Interrupting rating was not modeled as device switching was not contemplated for the analyses.
- Only normally closed switches were modeled, as no feeder reconfiguration was contemplated. Switches were rated in accordance with their “Capacity_A” parameter from the GIS.
- For switches, if the connectivity could not be discerned from the feeder topology, the switch was <u>not</u> modeled.

- The existing PV systems were not assigned to a particular feeder or conductor segment in the GIS. As such, it was necessary to use GIS analysis to assign the individual systems to the geospatially closest conductor segment that matched its phase configuration, i.e. single-phase systems assigned to either single-phase lines and three phase systems assigned to three phase lines. EE Plus cannot guarantee that this methodology represents with 100% fidelity with the physical system, but it is believed to provide at least a reasonable approximation thereof.

B. Analytical Assumptions

In addition to the assumptions necessary to correct or fill in gaps in the data, it was necessary to make some overarching assumptions about the distribution system to appropriately model it in OpenDSS. For the most part, these assumptions were based on distribution standards from PREPA.

The first of the analytical assumptions were relevant to the substation transformer. EE Plus explicitly modeled the substation transformers within the Open DSS models. Transformer size, both normal and emergency, were as promulgated in the GIS database. All substation transformers were assumed to have a ±16 set on load tap changer (LTC), regulating to ±10% of the nominal transformer secondary voltage. The setpoint of the LTC was set at 1.03 per unit or 123.6 V on a nominal 120 V base. The impedance and X/R ratio of the transformer was in accordance with IEEE C57.12.00-2015 (IEEE Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers).

Overhead conductors were assumed to be mounted on 35’ Class 3 poles. Additional reinforcement or resiliency measures that have or may be undertaken by PREPA were <u>not</u> included as part of the OpenDSS model. The framing of the poles and attendant overhead conductors were based on drawings from “Patrones De Construcción De Distribución Aérea” or Aerial Distribution Construction Patterns, obtained from the PREPA website (1986 version). Note that “narrow” profile construction, using standoff brackets, was assumed, rather than conventional crossarm construction. Also, where the conductor type was “spacer”, narrow profile spacer brackets were assumed to have been used, similar to the illustration in Figure III-1 below. Conductor ampacity was determined using the methodology described in IEEE 738-2012 (IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors). Other parameters required to fully define the conductor within the OpenDSS models were obtained from (Square D Company, 2006) and (Southwire Corporation, 2020).

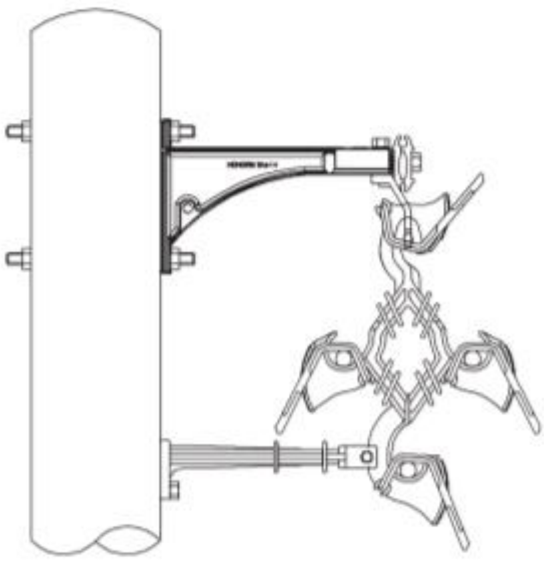

Figure III-1 – Triangular Cable Spacer Bracket **(source: Hendrix Aerial Cable Systems)**

Underground conductors within the GIS were similarly configured to fit within the OpenDSS modelling framework. For the purposes of this analysis, the concentric neutral model within OpenDSS was utilized, as opposed to the tape shield model. Data required for this modelling effort was obtained from (The Okonite Company, 2020). The installation configuration was based on Drawing URD-6, Page 7 Rev 1 (Trinchera Para La Instalacion Alimentadores Principales Primarios) of the Manual of Underground Distribution Patterns (PREPA, February 2002). The configuration was modeled as shown Figure III-2 in below. Underground conductor ampacity was determined based on data from IEEE 835-1994, IEEE Standard Power Cable Ampacity Tables. Cable terminations, cable elbows and switchgear bus were assumed to be rated for 200 A if the cable was #2 AWG AL or smaller, and 600 A if the attendant cable was larger than #2 AWG AL.

As noted above, capacitor banks were assumed to be composed of 100 kVAR cans, in multiples of three for three phase units, multiples of two for two phase units, and single cans for single phase units. All capacitors were assumed to be fixed, as no control information was provided.

Voltage regulators were assumed to be rated in accordance with the provided GIS data. Regulators were assumed to have ±16 steps, and operate in a range of ±10% of the nominal primary voltage. Secondary voltage was set to 1.03 per unit of the primary side voltage, with a 2 volt bandwidth, and a 2 minute time delay. Regulators were set to accommodate reverse power flow and regulate in either direction.

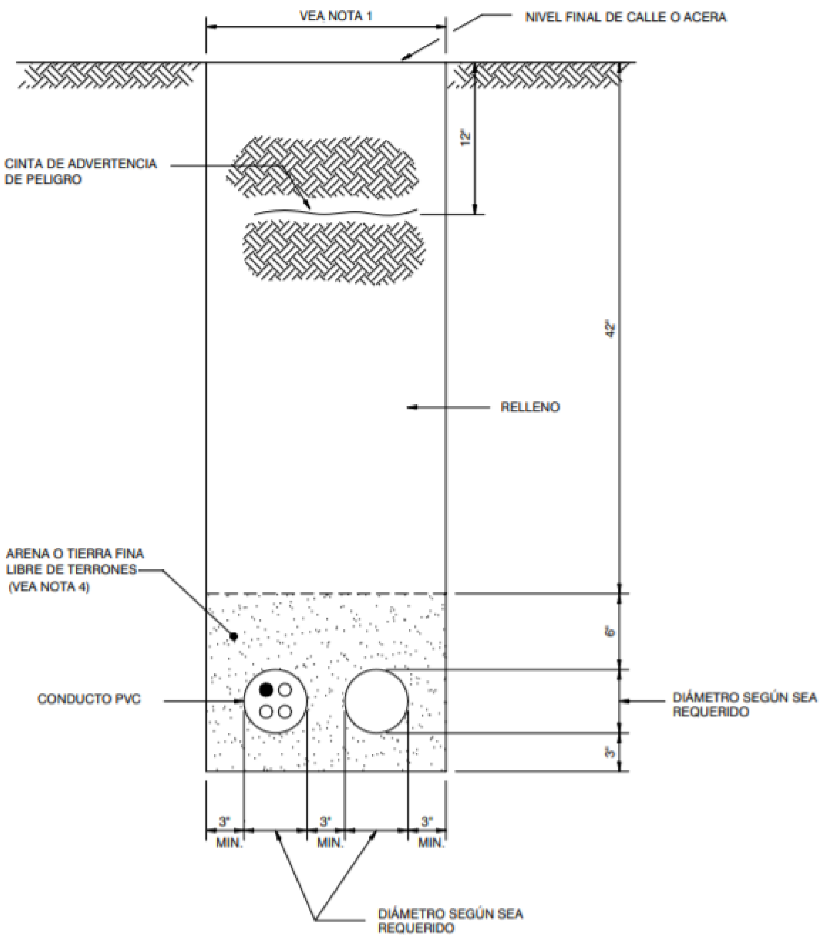

Figure III-2 – Typical Underground Conductor Installation

C. Transmission Interface Assumptions

The interface point between the transmission and sub-transmission systems, as modeled by Telos, was the primary side of each load serving substation transformer. In most cases this interface was at 38 kV. There were, however, some 115 kV buses that directly serve distribution loads as well as the transmission grid. Throughout the analyses, the transmission system was considered the “master” source, even when there was appreciable downstream generation. As referenced above, the transmission source was set to a value of 1.03 per unit.

The power factor for the secondary side of each substation transformer, which was ultimately inherited by all downstream loads, was set to the value of the load at the corresponding transmission bus within the Telos Plexos and PSS/e models. Likewise, Telos used the PSS/e model to define the source impedance of the transmission system at each load bus. This value was included as the positive sequence source impedance for the source on the primary side of the substation transformer.

Finally, the 8760 hour load shape associated with each region was allocated to the individual substations for both commercial and residential load, based on. The load shapes were used to define the interaction of the PV and BESS systems with the loads at each distribution substation bus. An example of a typical load shape for both residential and commercial loads are shown in Figure III-3 and Figure III-4 below.

Figure III-3 – Example of Residential Load Shape

Figure III-4 – Example of Commercial Load Shape

D. PV / BESS Interface Assumptions

The final set of assumptions were related to the application of both existing and contemplated PV and BESS systems. As noted above, the existing PV was connected to the physically closest feeder segment via GIS analysis, and the size and phase configuration was as documented in the GIS database. Only those systems whose status was “Connected Authorized to Operate” were included in the distribution models. Where battery systems were also included, it was assumed that the PV would charge the battery until the state of charge was 100%, and then flow power onto the grid or serve local load.

New PV / BESS combinations were added based on multiple criteria. PV/BESS systems were added to the distribution models at the location of existing transformer in the GIS. This allowed EE Plus to geospatially distribute the interconnections in a manner that was reasonable, as the presence of a distribution transformer inherently implies the presence of a load to serve. Note that regulating transformers and booster transformers were excluded from this placement exercise.

The number and type of individual PV/BESS systems at each location was based on the size and configuration of transformation at each geospatial location. Single phase transformation was assumed to serve primarily residential load, and three phase transformers were assumed to serve commercial loads. All residential systems were assumed to be a combination of 2.7 kW PV systems and 10 kWh BESS systems. An integer number of residential PV/BESS systems were added at each single phase transformer location, with the number allocated based on the size of the transformer; that is, a 10 kVA transformer location would receive fewer installations than a 37.5 kVA transformer location.

New PV systems were assumed to serve local load at the transformer location and simultaneously charge the BESS until the state of charge of the battery was 100%. In the absence of the PV system, the BESS was assumed to serve local load until the state of charge reach 10%. Note that the batteries were assumed to be charged from the PV system only; no direct charging from the grid was contemplated. PV/BESS systems were set to regulate their output voltage to 1.0 per unit.

Finally, the total new amount of both residential and commercial PV systems had to be matched to the scenario definitions associated with the transmission interface. This necessitated a two-step allocation process. The first step was to allocate the maximum value (in MW) of the regional commercial and residential PV, as determined by Plexos, to the individual transmission buses / distribution substations. This allocation was based on the load represented at each transmission bus within the PSS/e model. The second step was to allocate the requisite PV to each substation feeder. This allocation was based on the total connected kVA for each feeder on a given substation bus. As noted above, the residential systems were then geospatially distributed to the single phase transformer locations based on transformer size, and the commercial systems were lumped at the three phase transformer locations based on transformer size. Below shows a representation of how the systems were allocated for a sample feeder.

Figure III-5 – Example of PV System Placement

IV. Methodology

A. General Approach

The methodology for performing the various analyses required for the project was straightforward. Based on the assumptions discussed in the preceding section, models were developed for all substations and feeders for which a matching transmission bus from the PSS/e model could be identified. The matching process was largely manual, as there was not a consistent numerical key that could be used to tie the two models together. In some cases, there were transmission buses with no corresponding distribution substation in the GIS. Likewise, there were some distribution substations within the GIS that did not have an obvious match to a bus in the transmission model. In total however, EE Plus matched at total of 267 substations with a corresponding transmission model. This yielded a total of 987 feeders of the 1097 provided in the GIS or approximately 90%.

Because the GIS model used multiple ESRI shapefiles to present the distribution system data, EE Plus wrote multiple Python script files to extract the required modeling data from the GIS and write it to text files for use in OpenDSS. In addition to the basis data extraction used to construct individual feeder models, it was necessary to prepare additional OpenDSS files that were common among all feeder models. The general data structure used for all feeder models is shown in Figure IV-1 below. Note that an additional general file, defining the line geometry of the various styles of overhead lines and underground cables was included. Each substation also had a separate file defining the source impedance and substation transformer size. Finally, an individual file that defined the interconnection of the PV / BESS for each feeder was created for each development scenario. The explicit details of the field mapping between OpenDSS, the GIS and the Telos PSS/e models is provided in Volume III of this report.

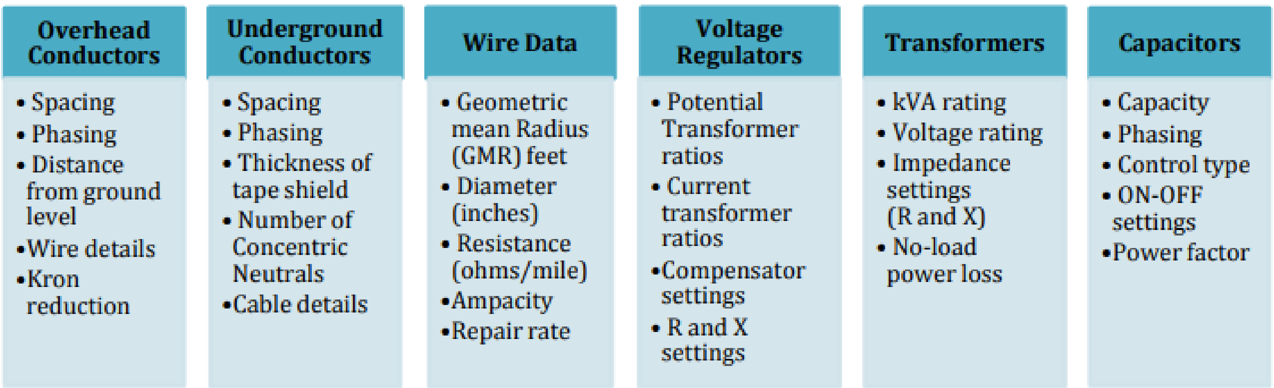

Figure IV-1 – OpenDSS data structure.

The Python scripts created the file grouping listed above for each modeled feeder. These were combined with the "common" files, regional load shape files and additional instructions within OpenDSS to perform the power flow analysis for each feeder. A group of reports were produced by the power flow analysis. These included the two main reports used to formulate the results for this report; the overload report and the voltage exception report. These reports flag instances where line currents or bus voltages are outside the evaluation criteria for the particular device. These results were cataloged for each scenario, identifying the line segments or buses that exhibited the violating performance. For the purposes of this summary report, the results of the violation analysis were aggregated to the regional level. Volume II of this report provides the breakdown by substation and feeder for the purposes of addressing specific mitigation needs.

B. Evaluation Criteria

As noted in the Assumptions sections, the ampacity ratings of the conductors and equipment were based on either their nameplate ratings, applicable IEEE standards or PREPA standards. It is important to note, that since the evaluations were based on "normal" operating (i.e. non-emergency) operating conditions, the normal steady state ratings of conductors and equipment were applied. The ampacity ratings of all conductors within the PREPA system are shown in Table IV-1 below. Note that while emergency ratings are included in the model for completeness, if a conductor exceeded the normal ampacity rating for even a single hour over the analysis horizon, it was cataloged as a violation.

Table IV-1 – Overhead Conductor Ampacity Ratings

Conductor Type	Normal Rating (Amps)
6_CU_HD	100
6_CU	100
4_CU_HD	120
2_ACSR	165
2_CU	170
1/0_ACSR	220
2/0_ACSR	250
1/0_AAAC	256
2/0_CU	275
1/0_CU	282
3/0_SPACER_15_KV	285
3/0_ACSR	285
3/0_AAAC	342
4/0_ACSR	357
4/0_CU	375
250_CU	430
266_ACSR	475
266_SPACER	475
3/0_CU	480
300_CU	485
336_SPACER	529
336_ACSR	529
556_ACSR	726
556_SPACER	726
652.4_AAAC	729
795_ACSR	907

Table IV-2 – Underground Cable Ampacity Ratings

Conductor Type	Normal Rating (Amps)
6_CU_XLP_5_KV	100
4_CU_XLP_15_KV	125
2_CU_XLP_15_KV	150
2/0_CU_XLP_15_KV	224
3/0_CU_XLP_15_KV	225
4/0_CU_XLP_15_KV	293
250_CU_XLP_15_KV	322
300_CU_XLP_15_KV	322
350_CU_XLP_15_KV	400
500_CU_XLP_15_KV	472
500_CU_EPR_15_KV	472
750_CU_XLP_15_KV	532
750_CU_EPR_15_KV	532
800_CU_XLP_15_KV	550
1200_CU_XLP_15_KV	667

Please reference

Table I-3 – List of Abbreviations for an explanation of the terminology used in these tables. For devices other than conductors, the nameplate rating as promulgated in the GIS database was used as both the normal and emergency rating.

In addition to the assessment of thermal (ampacity) violations, all buses were screened for steady state voltage violations as well. Voltage violations were defined based on ANSI C84.1-2020: Electric Power Systems Voltage Ratings. Specifically, Range A of this standard was used. It is defined in the standard as:

> *"Range A provides the normally expected voltage tolerance on the utility supply for a given voltage class. Variations outside the range should be infrequent".*

The applicable ranges used for evaluation of voltage violations are illustrated inFigure IV-2 below.

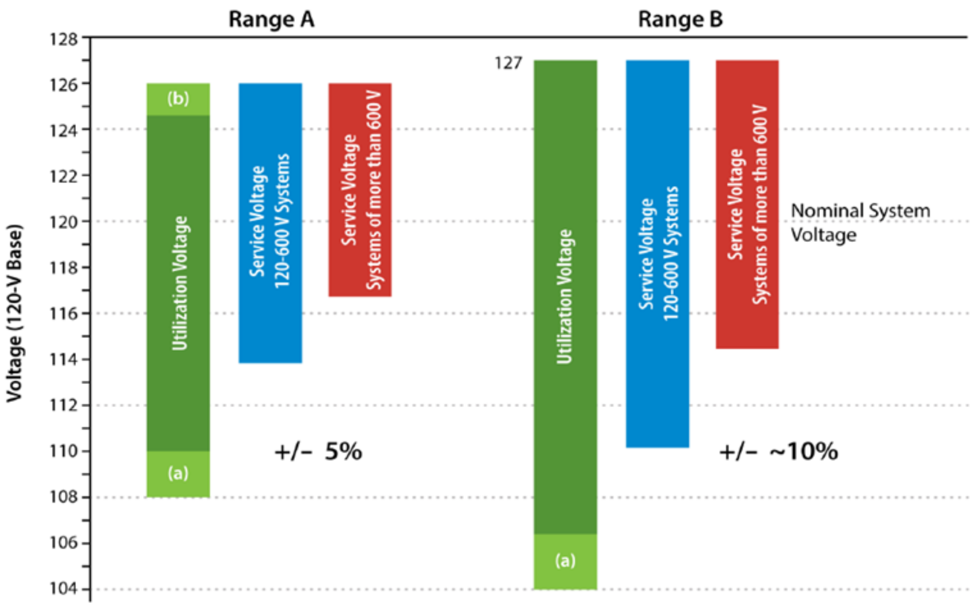

Figure IV-2 – Voltage Range for Violation Evaluation

Note that the voltage range for Service Voltage (Systems of more than 600 V), illustrated in the red bar above, were used as the evaluation criteria for bus voltages throughout the distribution system.

In addition to the conductor and device evaluations, for each substation and scenario, the capacity of the substation transformer was evaluated with all feeders simultaneously connected. If there was forward or reverse power through the substation transformer, in excess of the transformer's normal rating, the transformer was flagged for remediation. Individual distribution transformers were not evaluated for overload as the DER resource allocation methodology prevented the placement of excess (i.e. greater than the transformer size) DER at any given distribution transformer location. Distribution systems routinely have as much as 40% more connected kVA than actual load, so the appropriate level of DER penetration could be deployed without the risk of overloading individual transformers.

C. Mitigation / Remediation

To estimate the amount remediation necessary for a particular violation, two simple approaches were used. For thermal violations, the length of every conductor segment for which a violation was identified was aggregated for the by feeder and scenario. For voltage violations, the length of every conductor segment between busses exhibiting voltage violations were aggregated by feeder and scenario. Additionally, if only one bus, either the "from" or "to" bus of a line segment, exhibits a voltage violation, then the length of the segment immediately preceding the violating bus was included in the aggregation. The aggregation was stratified by multiple factors to determine the type of mitigation ultimately applied. The stratification / classification included:

- Number of phases (note: phase rotation was not classified);
- Operating voltage;
- Existing conductor type / size;
- Overhead or underground installation; and
- Type of violation (voltage or thermal or both).

Based on this characterization, a second iteration (and in some cases multiple iterations) of the analysis was applied with modified conductor sizing for the violating line segments / busses. If the violations were mitigated, these sizes were accepted as the appropriate remediation for the given scenario. If they were not, an additional iteration was performed with larger conductor sizes applied to the segments that were still in violation of the evaluation criteria. This process was repeated to until no violations were noted.

Mitigation of substation transformer loading was evaluated only for peak power flow values, as these define the MVA size by which the transformer must ultimately be increased. While in practice, PREPA would likely upgrade the transformer to next "standard" size within their transformer fleet, for analytical purposes only the MVA overload was considered.

In determining the type and ultimate cost of the system improvements necessary to mitigate the identified violations, the following rules were applied:

- Mitigation necessary to accommodate the 75% scenario were the only system improvements contemplated;
- Improvements to lines were based on the practical limitations for distribution construction:
    - If the mitigation required an increase in conductor size of less than or equal to two sizes, the line would be reconductored (i.e. poles and arms retained, conductor replaced).
    - If the mitigation required an increase in conductor size of more than two conductor sizes, the line would be completely rebuilt in the violating sections.
- If transformer reverse power overloads are less than 125% of the emergency rating of the transformer for no more than 500 hours annually – no upgrade was

applied.

- Power flows greater than 125% of the emergency rating of the transformer for more than 500 hours annually – replacement of the transformer was assumed.

Note that the emergency rating of the transformer was selected because most transformers of this type will accommodate short term overloads without appreciably shortening their useful life.

V. Results

The results of each scenario are presented below. For brevity, these have been aggregated to the highest level; region and type of mitigation to be applied. A breakdown of remediation by feeder, conductor type and number of phase conductors is presented in Volume II of this report. Note that each of the DER penetration cases represent “incremental” infrastructure improvement beyond the base case. However, the nature of the mitigation varies as the level of penetration increases (i.e. under-voltage conditions replaced by localized over-voltage conditions, along with variations in the location and severity of thermal overloads.

A. Base Case Scenario

The base case scenario is based on the application of regional load shapes and the regional PV profile over an 8760 hour period (1 year), using only the existing PV, as provided by PREPA, as DER.

Region	Total Line Miles	Line Miles Reconductor	Line Miles Rebuild	% Mitigation	Transformer Upgrades
Arecibo	4,790	13.7	315.9	6.9	0 MVA
Bayamon	2,442	81.7	106.6	7.7	0 MVA
Caguas	6,761	136.9	317.3	6.7	0 MVA
Carolina	3,310	100.7	140.8	7.3	0 MVA
Mayaguez	5,482	37.7	303.9	6.2	0 MVA
Ponce ES	2,828	12.1	127.7	4.9	0 MVA
Ponce OE	2,526	21.4	125.5	5.8	0 MVA
San Juan	2,908	29.1	95.2	4.3	0 MVA
Vieques	166	0.8	10.4	6.7	0 MVA

Culebra	68	1.0	2.4	5.0	0 MVA

B. 25% Penetration Scenario

The 25% penetration case scenario is based on the application of regional load shapes and the regional PV profile over an 8760 hour period (1 year), including the existing PV and residential and commercial PV placed as described in Section III.D as DER.

Region	Total Line Miles	Line Miles Reconductor	Line Miles Rebuild	% Mitigation	Transformer Upgrades
Arecibo	4,790	11.6	278.2	6.1	0 MVA
Bayamon	2,442	73.5	93.8	6.9	0 MVA
Caguas	6,761	123.2	278.9	5.9	0 MVA
Carolina	3,310	90.7	114.7	6.2	0 MVA
Mayaguez	5,482	33.9	264.0	5.5	0 MVA
Ponce ES	2,828	10.9	111.8	4.3	0 MVA
Ponce OE	2,526	19.3	109.1	5.1	0 MVA
San Juan	2,908	20.4	84.6	3.6	0 MVA
Vieques	166	0.7	9.8	6.4	0 MVA
Culebra	68	0.8	2.2	4.3	0 MVA

C. 50% Penetration Scenario

The 50% penetration case scenario is based on the application of regional load shapes and the regional PV profile over an 8760 hour period (1 year), including the exitsing PV and residential and commercial PV placed as described in Section III.D as DER

Region	Total Line Miles	Line Miles Reconductor	Line Miles Rebuild	% Mitigation	Transformer Upgrades
Arecibo	4,790	16.5	344.1	7.5	3 MVA
Bayamon	2,442	63.2	117.2	7.4	5 MVA
Caguas	6,761	117.7	349.9	6.9	11 MVA
Carolina	3,310	86.6	160.1	7.5	4 MVA

Mayaguez	5,482	32.4	335.6	6.7	6 MVA
Ponce ES	2,828	10.4	153.1	5.8	3 MVA
Ponce OE	2,526	18.4	149.8	6.7	5 MVA
San Juan	2,908	24.8	105.0	4.5	12 MVA
Vieques	166	0.7	11.4	7.3	0 MVA
Culebra	68	0.8	3.1	5.6	0 MVA

D. 75% Penetration Scenario

The 75% penetration case scenario is based on the application of regional load shapes and the regional PV profile over an 8760 hour period (1 year), including the exiting PV and residential and commercial PV placed as described in Section III.D as DER

Region	Total Line Miles	Line Miles Reconductor	Line Miles Rebuild	% Mitigation	Transformer Upgrades
Arecibo	4,790	19.0	381.8	8.4	15 MVA
Bayamon	2,442	114.4	131.0	10.1	22 MVA
Caguas	6,761	191.6	384.0	8.5	30 MVA
Carolina	3,310	141.0	172.3	9.5	15 MVA
Mayaguez	5,482	52.7	365.7	7.7	18 MVA
Ponce ES	2,828	16.9	160.0	6.3	11 MVA
Ponce OE	2,526	26.8	177.3	8.1	10 MVA
San Juan	2,908	35.0	133.4	5.8	28 MVA
Vieques	166	1.0	14.5	9.3	0 MVA
Culebra	68	1.2	3.6	7.1	0 MVA

PUERTO RICO DISTRIBUTED ENERGY RESOURCE INTEGRATION STUDY

Load, Energy Efficiency, and System Cost

FEBRUARY 2021

ENERGY FUTURES GROUP

Puerto Rico Distributed Energy Resource Integration Study – Load, Energy Efficiency, and System Cost

Achieving a Renewable, Reliable, and Resilient Distributed Grid

CAMBIO

ENERGY FUTURES GROUP

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Disclaimer

This model has been independently developed by CAMBIO, PR Inc in collaboration with IEEFA and consultants and in no way represents any proposal, projection or representation of the Puerto Rico Electric Power Authority.

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1. Executive Summary

In October 2018, Queremos Sol – a multisector group advocating for self-sufficient and sustainable energy - released a report entitled, "Queremos Sol: Sostenible, Local, Limpio."[1] In the report, Queremos Sol set an ambitious goal to achieve a Renewable Portfolio Standard (RPS) of 50% by 2035 and 100% by 2050, and an Energy Efficiency and Conservation Policy Objective of 25% by 2035. In addition, it advocated for a clear public policy for the following:

- Efficiency, conservation, and demand management.
- Renewable distributed generation based on rooftop solar and storage
- Accelerated elimination of fossil fuels.

At the request of CAMBIO and the Institute for Energy Economics and Financial Analysis (IEEFA), Energy Futures Group ("EFG") collaborated with consulting firms Telos Energy ("Telos") and EE Plus to conduct an analysis of the feasibility, operability, and cost of achieving two energy goals related to the Queremos Sol proposal. Specifically, this collaborative effort sought to examine the operational and cost impacts of achieving a 25%, 50%, and 75% RPS target with two, primary tools:[2]

- Ensuring 50%, 75%, and 100% of homes in Puerto Rico are "resilient" to hurricanes. Resiliency was defined as each home having, on average, 2.7 kW of solar and 12.6 kWh of battery backup; and
- Achieving a 25% reduction in island-wide energy consumption by 2035.

These scenarios provide a pathway to meet and exceed the Queremos Sol 2035 RPS objectives and put the system on a trajectory to achieve 100% clean energy by 2050. The study participants also constructed, for comparison purposes, a Base Case of the system as it exists today.

The analysis of the DER and energy efficiency goals involved a coordinated, detailed, and unique combination of modeling simulations looking at the dispatch of Puerto Rico's fleet of generators under these differing scenarios and the operation of the distribution and transmission lines under that dispatch. EFG's role was to develop the load and energy efficiency assumptions and then bring together data from all the simulations into a total system cost. (Collectively, we call these analyses the "CAMBIO Study".) The dispatch and power flow modeling is detailed in Telos Energy's report, while EE Plus's report discusses the distribution system simulations.

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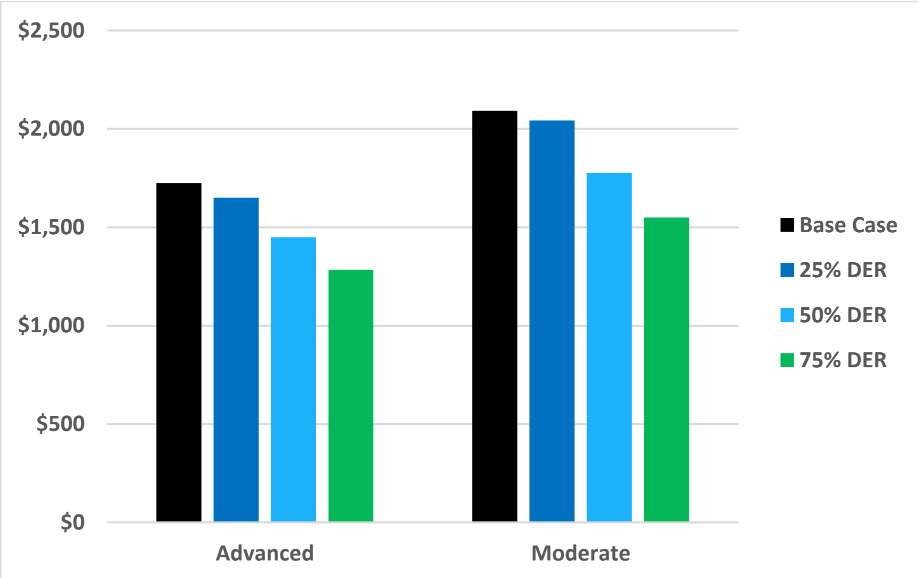
[1] Queremos Sol, https://www.queremossolpr.com/

[2] Distributed solar with battery storage and energy efficiency were the primary distributed energy resources (DER) deployed in the study scenarios.

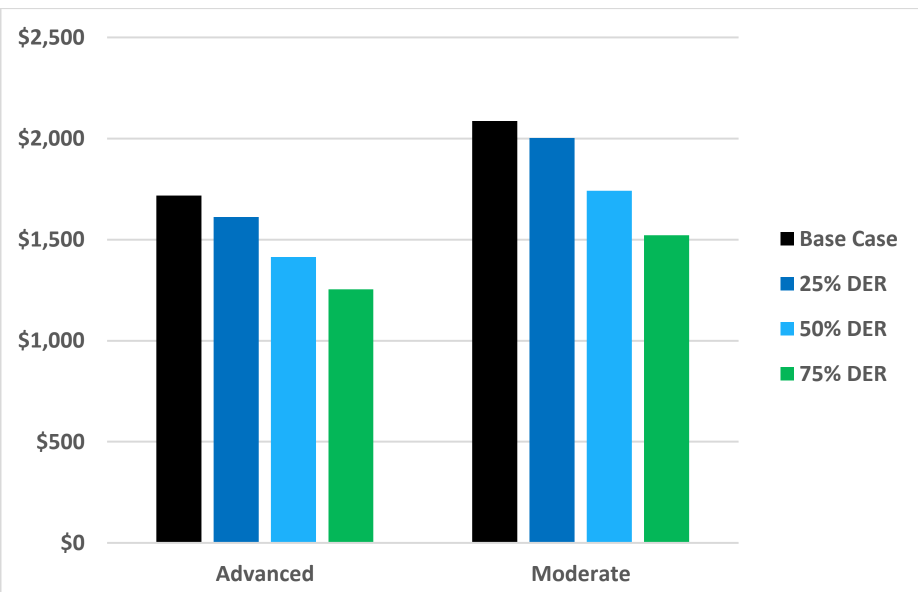
Under a discount rate similar to PREPA's cost to raise debt before it filed for bankruptcy, all DER scenarios are cheaper than a business-as-usual case (Base Case) as shown in Figure 1.

Figure 1: Total Operating & Carrying Costs at 6.5% (Millions of 2020$)



If we assume that these scenarios should be judged using a discount rate that is more indicative of an individual ratepayer's personal financing rate for a rooftop solar and battery storage system, then all DER scenarios become even lower cost relative to the Base Case (Figure 2).

Figure 2. Total Operating and Carrying Costs at 3.99% (Millions of 2020$)



It is important to note that the Base Case assumes Puerto Rico's electric grid continues largely as it stood in 2020. There are no additional distributed renewables or natural gas nor any maintenance upgrades of the existing fleet. Because the DER scenarios, with increasing penetration, decreasingly rely upon PREPA's current thermal fleet there is a reliability benefit (in addition to a resiliency benefit) to the DER scenarios that is not quantified or monetized. We largely do not capture that concern in this study because we have no meaningful method to assess this value despite its very real nature. However, the DER scenarios indubitably provide more reliability because they would allow between 500,000 and 1 million households the ability to meet their critical loads even after a critical event such as a hurricane.

2. Putting the CAMBIO Study in Context

The Puerto Rico Electric Power Authority ("PREPA") is responsible for electricity generation, power distribution, and power transmission in Puerto Rico. The design of Puerto Rico's electrical grid, as is typical of most systems, has been a centralized approach that includes large fossil fuel power plants that rely on long transmission lines to bring power from the generators located in the southern portion of the island to the load centers located in northern Puerto Rico. Relying on large-scale generators to supply power to residents makes Puerto Rico's grid vulnerable to wide scale power outages from natural disaster and other events. Exacerbating the vulnerability of the electrical grid in Puerto Rico is PREPA's history of mismanagement and lack of investment in necessary infrastructure.

The destruction wrought by Hurricanes Irma and Maria brought attention to the important role that a decentralized electrical grid could play in providing resiliency in the face of natural disasters. Following hurricanes Irma and then Maria in 2017, 25% of the transmission towers and 40% of the 334 substations were damaged, which left millions of Puerto Ricans without power for a significant period of time.[3] While most of PREPA's generation assets were not damaged from the hurricanes, several earthquakes in 2020 caused severe damage to the Costa Sur units. Costa Sur is one of the largest power plants on the island and supplies about 25% of the electric power in Puerto Rico.[4] In order to mitigate the loss of Costa Sur, the Federal Emergency Management Agency ("FEMA") provided funds to cover costs for 28 peaking generator units to operate until the Costa Sur units could come back online.[5] The combination of the transmission and distribution damage from the hurricanes and the damage to Costa Sur caused by the earthquakes, put in stark terms the dangers of relying on a primarily centralized electric grid in Puerto Rico. These experiences show the importance of the need for Puerto Rico's electric grid to focus on decentralized generation for resiliency and sustainability. The broadening use of distributed solar PV and energy storage, in addition to implementing energy efficiency and demand management to help lower customer use of electricity, would all

[3] O'Neill-Carrillo, E., & Irizarry-Rivera, A. (2019). How to Harden Puerto Rico's grid against hurricanes. *IEEE Spectrum*, *56*(11), 42-48.

[4] https://www.fema.gov/press-release/20201013/fema-obligates-over-238-million-prepa-earthquake-damage

[5] Ibid.

contribute to a more resilient grid. The use of local and renewable generation will also provide the benefit of fostering the socio-economic development of communities.[6]

After the hurricanes, multiple organizations internal and external to Puerto Rico focused on how to rebuild the island's grid. The National Science Foundation funded several sessions to discuss stakeholder visions on how to rebuild Puerto Rico's electric system. Those stakeholder groups included professionals from the energy committee from the Puerto Rico Chamber of Commerce, local trade organization of PV installers and contractors, members of communities across the island, and employees from an out-of-state utility that helped with restoration. During these activities, several focus groups discussed what went wrong with the electric system once the hurricane hit and recommendations to avoid those problems in the future. One of the focus groups included members of professional and trade organizations who noted that rooftop PV systems did not see much damage. Given the strength of winds during the hurricanes, this was clear evidence that when rooftop PV systems are correctly installed, they are able to withstand hurricane-force winds.[7] Not only can solar PV systems help foster resiliency for residents and communities during natural disasters, but solar PV systems have become economically feasible in Puerto Rico.[8,9] The average price of electricity in Puerto Rico has ranged between 20 and 27 U.S. cents per kWh, and this is anticipated to rise above 30 U.S. cents per kWh if a rate increase is factored in for servicing PREPA's debt obligation.[10] In comparison, our study estimates that the cost of a PV system in Puerto Rico in 2021 is about 9.8 cents per kWh. Solar PV is also a very viable resource, since approximately 70% of the population resides in a location with an excellent solar resource.[11] The combination of economic feasibility and resiliency make rooftop solar PV systems a viable option for utilizing local generation.

One of the main criticisms against widespread adoption of rooftop solar PV systems is the variation in generation that occurs with renewable resources. Several studies have looked at a combination of microgrid systems integrating solar PV, energy storage, and demand

[6] O'Neill-Carrillo, E., & Irizarry-Rivera, A. (2019). How to Harden Puerto Rico's grid against hurricanes. *IEEE Spectrum*, *56*(11), 42-48.

[7] Oneill, E., McCalley, J., Kimber, A., & Haug, R. (2019, January). Stakeholder perspectives on increasing electric power infrastructure integrity. In *ASEE annual conference & exposition*.

[8] O'Neill-Carrillo, E., Jordan, I., Irizarry-Rivera, A., & Cintron, R. (2018). The long road to community microgrids: adapting to the necessary changes for renewable energy implementation. *IEEE Electrification Magazine*, *6*(4), 6-17.

[9] O'Neill-Carrillo, E., Mercado, E., Luhring, O., Jordán, I., & Irizarry-Rivera, A. Community Energy Projects in the Caribbean.

[10] O'Neill-Carrillo, E., & Irizarry-Rivera, A. (2019). How to Harden Puerto Rico's grid against hurricanes. *IEEE Spectrum*, *56*(11), 42-48.

[11] O'Neill-Carrillo, E., Jordan, I., Irizarry-Rivera, A., & Cintron, R. (2018). The long road to community microgrids: adapting to the necessary changes for renewable energy implementation. *IEEE Electrification Magazine*, *6*(4), 6-17.

management to serve households in communities within Puerto Rico.[12,13] In order to address the concerns related to cloudy days or large-scale system outages, energy storage will need to be co-located with the rooftop PV so that households can still serve their critical loads during those periods of time.

With broader adoption of rooftop solar PV across Puerto Rico, microgrids become more feasible as well. Microgrids consist of local distributed energy resources and loads, and they can operate in two different modes: grid-connected and isolated from the grid. When a microgrid is in grid-connected mode, it can import or export power to the main electricity grid. When a microgrid is in isolated mode, it relies on the local generation resources to supply power to the customers connected to it. Microgrids offer more resiliency than the centralized power system structure in the face of natural disasters.[14] In the event of a natural disaster, such as Hurricane Maria, microgrids can help critical facilities remain operational and they can also help provide power for rural communities who are not easily restored following power outages.

Utilizing local resources can also provide resiliency, in addition to economic, social, and environmental benefits to Puerto Rico. There is a large potential role for communities to play in establishing and managing their grids. There is the potential to build on Puerto Rican experience managing community-based projects primarily through community-operated water aqueducts in over 200 rural communities that own the water resource and manage the distribution system.[15]

The CAMBIO study looks fifteen years down the road to a time when Puerto Rico has retired the dirtiest of its fossil-fuel power plants, has made a coordinated and extensive effort to ensure resilient and efficient production and consumption of electricity, and has upgraded its distribution system to best practice standards. The primary purpose of this study was to assess the feasibility and cost of achieving the 2035 resiliency goals previously discussed. Both this and Telos' report also discuss a sensitivity looking at a 2024 stepping stone that will enable Puerto Rico to achieve a 75% resilient homes goal.

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[12] O'Neill-Carrillo, E., Jordan, I., Irizarry-Rivera, A., & Cintron, R. (2018). The long road to community microgrids: adapting to the necessary changes for renewable energy implementation. *IEEE Electrification Magazine*, *6*(4), 6-17.
[13] Jordán, I. L., O'Neill-Carrillo, E., & López, N. (2016, October). Towards a zero net energy community microgrid. In *2016 IEEE Conference on Technologies for Sustainability (SusTech)* (pp. 63-67). IEEE.
[14] Carrión, G. A., Cintrón, R. A., Rodríguez, M. A., Sanabria, W. E., Reyes, R., & O'Neill-Carrillo, E. (2018, November). Community microgrids to increase local resiliency. In *2018 IEEE International Symposium on Technology and Society (ISTAS)* (pp. 1-7). IEEE.
[15] O'Neill-Carrillo, E., Mercado, E., Luhring, O., Jordán, I., & Irizarry-Rivera, A. Community Energy Projects in the Caribbean.

3. Load and Energy Efficiency

Perhaps the single most important input into a study such as this is the load forecast or a projection of how much energy consumers will demand. Total load is a function of the number of customers in each class (residential, commercial, industrial, etc.), the types of electrical end-uses (refrigerators, air conditioning units, etc.), and the impacts of any programs intended to influence electrical consumption, e.g. energy efficiency programs. In Puerto Rico, there exists data on consumption by customer class, but very little data on typical end-uses. And with no meaningful history of energy efficiency ("EE") in Puerto Rico, it is a real challenge to develop reliable projections of energy efficiency savings or of the impact of natural uptake of efficient technologies on Puerto Rico's overall system load.

Prior load forecasts produced for PREPA's Integrated Resource Plan ("IRP") filings are publicly available. However, those forecasts include no adjustment for "naturally occurring"[16] energy efficiency which, in our opinion, makes them unreliable.

In its most recent IRP filing, PREPA included detailed information for a hypothetical set of energy efficiency programs. Unfortunately, the combination of flawed effective useful life assumptions[17] and limited measure types also makes those figures less than reliable.

Because a prediction of load is so key to planning exercises like this one and because the island now has robust energy efficiency goals established by the Puerto Rico Energy Bureau, a different approach to forecasting load and EE was needed. EFG performed a high-level analysis of the aggregate effect of the following factors in reducing electric energy use on the Island between 2020 and 2035:

- "Naturally-occurring" energy efficiency that reduces electricity use due to:
  - Technology innovations and market pressures that increase baseline equipment efficiencies;
  - Increasing federal appliance and equipment efficiency standards;
- Energy efficiency programs implemented by PREPA or others to provide informational and financial support to customers in making energy efficiency improvements for their homes and businesses;
- Large-scale replacement of residential electric water heating with solar water heating.

Because of the dearth of information on the end-use characteristics of the Island's electric loads, it was necessary for EFG to make several significant assumptions in order to carry out the

[16] Naturally occurring energy efficiency is energy savings that occur under normal market forces without intervention. A major driver of naturally occurring energy efficiency is increasing appliance standards. These standards cause the minimum efficiency of electrical consuming technologies available in the market to increase over time and drive an increase in the average efficiency of the stock of those appliances. That, in turn, causes electricity consumption to go down.

[17] Meaning that PREPA assumed that energy efficiency measures such as LED lightbulbs had lifetimes well in excess of the assumptions typically made for energy efficiency measures.

analysis. First, Puerto Rico lacks reliable appliance saturation data that would characterize existing consumption by end-use type,[18] so we looked to another source, specifically the Energy Information Administration's projection of nationwide average end-use efficiency to determine the consumption of existing end-use technologies. Using information from the Electric Power Research Institute and from a study led by Dr. Irizarry,[19] we developed an estimate of the combined impact of the EIA's projected end-use efficiency and the consumption by those end-uses in Puerto Rico. EFG believes the results are illustrative of a path that leads to Queremos Sol's 25% cumulative energy consumption reduction goal but cautions that a next critical step to defining the path will be further research and data gathering.

These are the steps we took to develop forecasted 2035 load:

Step 1: 2020 Sector Loads

EFG used the average of the PREPA historical sector loads for 2016, 2018, and 2019 from PREPA's most recent IRP as the basis for establishing annual consumption by customer class in 2020. We did not use 2017 data for the obvious reason that system-wide outages after Hurricane Maria rendered those data unrepresentative of expected usage under typical conditions. We could not fully remove the impact of the hurricane related outages since hundreds of thousands of people remained without power well into 2018. But we also felt it could be important to capture how load may have changed because of the hurricane even after service was returned, so we tried to strike a balance by taking the average of 2016, 2018, and 2019. For each sector, the three-year average sector load was divided by the reported number of accounts to determine the expected load for an average account/customer within the sector.

Step 2: Naturally Occurring Energy Efficiency

In Step 2, EFG estimated the potential "naturally occurring" energy efficiency, i.e. the reductions that will occur in the expected energy requirements of typical sector loads over time due to technology improvements and advances in codes and standards. To do this, EFG first had to disaggregate the average sector loads by end use, as different levels of naturally occurring efficiency are expected for different types of loads.

For example, the average 2020 residential energy load that was determined in Step 1 above is 4,650 kWh per year. This is the total, on average, of the electric use of all of the

[18] A residential appliance saturation study ("RASS") should be undertaken to more definitively understand the electric consumption characteristics of Puerto Rico's homes. A similar energy use baseline study should also be undertaken to understand the load characteristics of the Island's business customers. The data supplied by these studies will be useful to refine energy efficiency program concepts and applications in order to implement a broad and meaningful set of energy efficiency programs that will achieve the desired savings.

[19] Irizarry-Rivera, Agustín, et al. "A case study of residential electric service resiliency through renewable energy following hurricane Maria," Mediterranean Conference Power Generation, Transmission, Distribution, Energy Conversion (MEDPower), Dubrovnik, Croatia, Nov 12-15, 2018.

different electrical equipment in a home including lighting, refrigeration, cooling, and so on. The amount of electricity used by different end uses varies by region due to differences in climate, economic conditions, and other factors, and as was mentioned above there are virtually no data on electric use by end use specific to Puerto Rico. Therefore, EFG estimated end use electricity by category for the residential and commercial sectors.

EFG used end use load shapes that are available from the Electric Power Research Institute ("EPRI") for Florida as a starting point, and then adjusted the estimated use by end use category based on input from Dr. Irizarry. Specifically, compared to the EPRI Florida data, as a percentage of total residential loads, cooling and water heating electric use were increased significantly for Puerto Rico, refrigeration was increased slightly, and clothes dryer, dishwasher, lighting, and home electronics use were all decreased significantly.

EFG then applied estimates of naturally occurring energy efficiency through 2035 to each of the disaggregated adjusted end use loads, using the change in projected end use energy by category from the Energy Information Administration's 2020 Annual Energy Outlook 2020.

Step 3: Energy Efficiency Programs

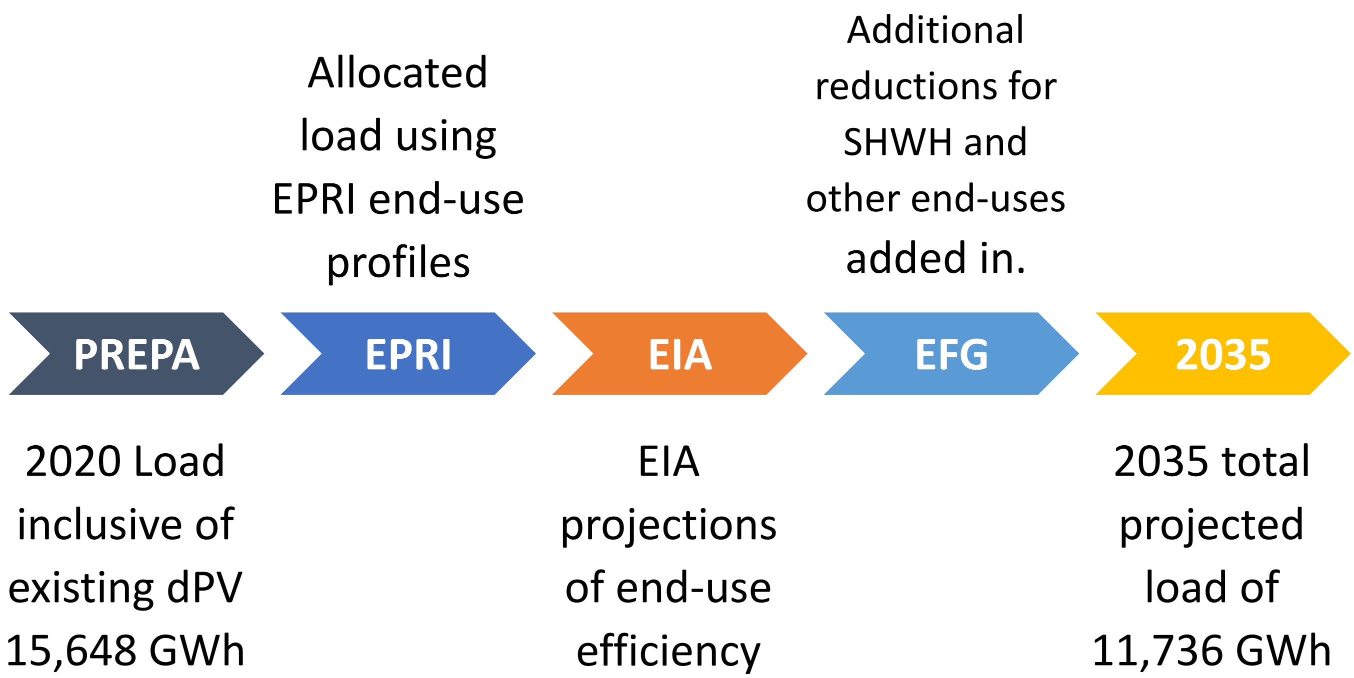
On top of naturally occurring energy efficiency EFG assumed savings in certain end uses based on implementation of energy efficiency programs. In the residential sector EFG estimated that the loads for cooling, lighting, and home electronics could all be reduced through efficiency programs more than would be possible simply through naturally occurring energy efficiency. Similarly, in the commercial sector EFG assumed additional program savings for cooling, lighting controls, refrigeration, office equipment and computing, as well as miscellaneous commercial loads. The adjustments were made on the basis of expert judgment – EFG staff have critically evaluated and helped developed hundreds of energy efficiency programs.

Step 4: Solar Water Heating

Given that residential water heating is estimated to consume as much as 30% of 2020 household electric use and given the abundance of solar resources in Puerto Rico, EFG included in its load forecast the assumption that aggressive programs to encourage solar hot water heating ("SHWH") could achieve a total conversion of 70% of residential electric hot water heating to solar by 2035.

These steps are illustrated in Figure 3. Our 2020 estimated starting point load was 15,648 GWh of sales. This was the figure from which the energy efficiency and solar hot water heating adjustments that would occur through 2035 were subtracted.

Figure 3. Flow Chart of EFG's Process to Develop a 2035 Load Projection



Applying the steps listed above to account for feasible energy efficiency and hot water heating conversions results in projected 2035 sales of 11,736 GWh – a total reduction of 25 percent. This is the level of energy that must be supplied through all modeled scenarios and sensitivities with one exception. The Accelerated Retirement sensitivity discussed in Telos Energy's report and later in this document was based on projected 2024 load. We used the same approach described previously to develop our 2024 load assumption though we conservatively assumed that solar hot water heating conversions would have no significant impact on load by 2024. This gave us an 11 percent reduction in energy consumption for total sales of 13,392 GWh.

4. New Resource Pricing

A significant task within EFG's scope of work in this study was to develop cost estimates for the distributed energy resources (DERs) in each scenario. Three primary cost assumptions needed to be developed: residential PV, commercial PV, and residential scale batteries. The explosion of interest and adoption of these technologies throughout the U.S. has generated more and better quality data characterizing their costs than has been the case in years prior. However, Puerto Rico has some important differences from other parts of the U.S. including different tax rates, a different supply chain, and different labor costs. We, therefore, sought to gather information specific to Puerto Rico as much as possible, though there is little publicly available in the way of PV and battery prices.

4.1. Residential and Commercial Solar (PV)

In consideration of the many factors that make pricing DERs in Puerto Rico a unique exercise, we relied on residential PV prices provided to us by CAMBIO. These data are for estimates to construct multiple residential rooftop installations. Just as in other jurisdictions, we expect that prices will decline over time. So going forward from 2020 we applied National Renewable Energy Lab's (NREL) Alternative Technology Baseline[20] (ATB) cost curve to the starting point data provided to us by CAMBIO. This yields two trajectories of declining costs. Using the nomenclature adopted by NREL, the first is a Moderate case, i.e., a business as usual case. And the second is the Advanced Case which assumes greater R&D and innovation in solar technology.[21] All estimates include the cost of the PV panels themselves, as well as Balance of System (BoS) and financing costs.

The key assumptions used to determine both total capital expenditure (CAPEX) and the economic carrying charge ("ECC", a mortgage payment equivalent view of cost) were:

1. 2020 Residential Solar Price - $1.86 per W_{DC}; this includes all costs needed to permit and construct the solar panels.[22]
2. Inflation Rate
    - This value was set at 2.5% consistent with NREL's ATB inflation assumption.
3. Discount Rate[23] (WACC)
    - The WACC was set to 6.5% as a proxy for PREPA's cost to raise debt.[24]
    - A second sensitivity was conducted assuming a 3.99% discount rate. This discount rate is an estimate of the financing rate an individual would face to finance a rooftop solar and battery storage system if that system were also accompanied by a guarantee or some form of buy-down (either by the Puerto Rican or federal government).

[20] https://www.nrel.gov/news/program/2020/2020-annual-technology-baseline-electricity-data-now-available.html

[21] More information about NREL's development of both cases is available here: https://atb.nrel.gov/electricity/2020/index.php?t=sr

[22] Estimate based on direct quote for a 2020 Puerto Rico community roof-top solar installation.

[23] A discount rate is necessary to account for the "time value" of money, i.e, the manner in which people differently value money in their possession now versus the future. There are different ways to set discount rates. A common way is to assume a proxy for the utility's cost to raise capital, we also use a proxy for an individual's cost to borrow money.

[24] This figure presumes that PREPA can emerge from bankruptcy and raise capital. Prior to its bankruptcy filing, PREPA issued bonds for long-term debt in the 5 – 7 percent range, so we chose a value that was conservatively high compared to the interest rates faced by other public power utilities.

Because we lacked any real-world data for commercial PV installations, we relied upon the ATB to characterize those costs entirely. The key assumptions used to determine both total capital expenditure (CAPEX) and the economic carrying charge were:

1. 2020 Commercial Solar Price - \$1.642 per W_{DC} in the Advanced case and \$1.664 per W_{DC} in the Moderate case; this includes all costs needed to permit and construct the facility but no financing costs.
2. Inflation Rate
    - This value was set at 2.5% consistent with NREL's ATB inflation assumption.
3. Discount Rate (WACC)
    - The WACC was set to 6.5% as a proxy for PREPA's cost to raise debt.
    - A second sensitivity was conducted assuming a 3.99% discount rate. This discount rate is an estimate of the financing rate an individual would face to finance a rooftop solar and battery storage system if that system were also accompanied by a guarantee or some form of buy-down (either by the Puerto Rican or federal government).

A primary goal of the study was to first meet the RPS objectives through distributed, rooftop solar, and secondarily through solar distributed across commercial and industrial customers, solar carports, and repurposed landfills. Because the ATB cost estimates for commercial PV installations are lower than the cost estimates for residential PV installations, the weighted cost of installation assumed varies across the scenarios. As the renewable energy target increases, the ratio of commercial to residential PV installations also increases. As a result, the final cost estimates represent an installed-capacity-weighted-average as shown in Table 1.

Table 1: Installed PV Price Estimates (2020 $/kW DC)[25]

	Unit	25% DER	50% DER	75% DER
Total PV Capacity	MW AC	1,493	3,237	4,982
Res PV Capacity %	Weight %	90%	63%	54%
C&I PV Capacity %	Weight %	10%	37%	46%
PV Cost (ATB Moderate)	$/kW DC	$1,857	$1,849	$1,846
PV Cost (ATB Advanced)	$/kW DC	$1,855	$1,840	$1,836

These cost estimates are adjusted annually using the ATB cost assumptions through 2035. Though total system costs are reported in the Executive Summary and in Section 5 for a single year, we did not assume that the solar and battery installations would be built overnight. Instead, in order to capture the reality of how Puerto Rico would achieve the level of DERs in each scenario, the project team developed an installation trajectory by year through 2035. Those trajectories are given in Table 2.

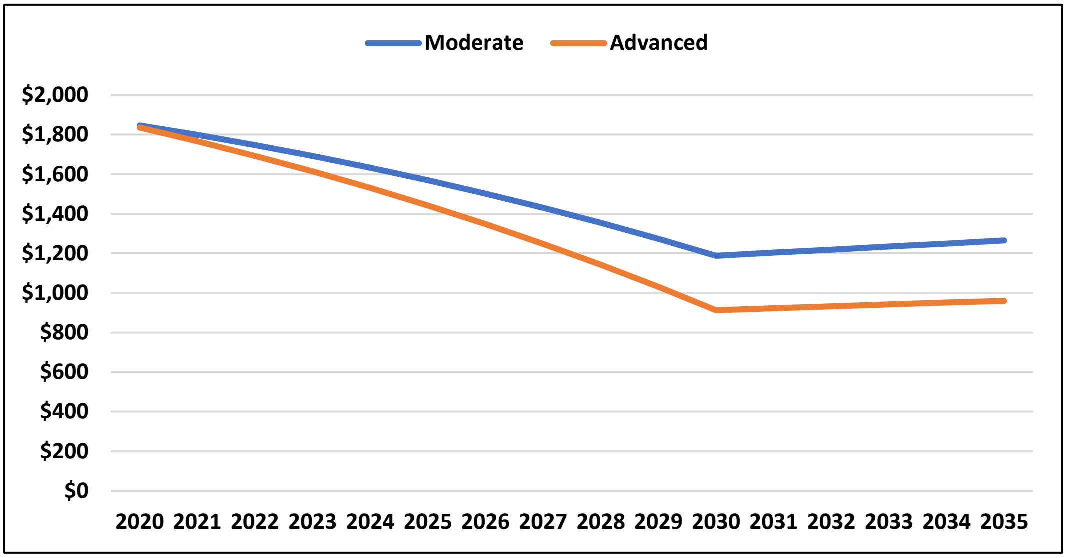
Table 2. Trajectory of Cumulative Solar Installations by Scenario (MW_{AC})

Fiscal Year	Base Case	25% DER	50% DER	75% DER
2020	172	172	172	172
2021	172	337	337	337
2022	172	502	502	502
2023	172	667	667	667
2024	172	833	833	833
2025	172	998	998	998
2026	172	1,163	1,163	1,163
2027	172	1,328	1,328	1,328
2028	172	1,493	1,493	1,493
2029	172	1,493	1,784	2,075
2030	172	1,493	2,074	2,656
2031	172	1,493	2,365	3,238
2032	172	1,493	2,656	3,819
2033	172	1,493	2,946	4,401
2034	172	1,493	3,237	4,982

The combined impact of that trajectory for the 75% DER scenario and the per unit cost predictions from the NREL ATB are given in Figure 4.

[25] Please note that the prices in this table do not include the impact of the ITC.

Figure 4: PV Weighted Price Cases, 75% DER (Nominal $/kW DC)



Please note that the weighted prices for the 25% and 50% DER cases are not shown but are slightly higher because they both include a higher percentage of residential installations, which are more expensive than commercial installations due to economies of scale.

To arrive at capital costs per year, these prices were multiplied by the installed capacity of solar PV per year as shown in Table 2.

4.2. Battery Energy Storage System (BESS)

The ATB's battery system costs are only offered at the utility-scale, so we turned to a popular website selling batteries for residential scale applications in Puerto Rico – the altE Store – to price the batteries that are installed with residential solar. These prices are specific to residential customers in Puerto Rico and adjustments were made so that the battery specifications were consistent with the manner in which they were modeled. As did Telos, we assumed an inverter efficiency of 96% applied to these systems.

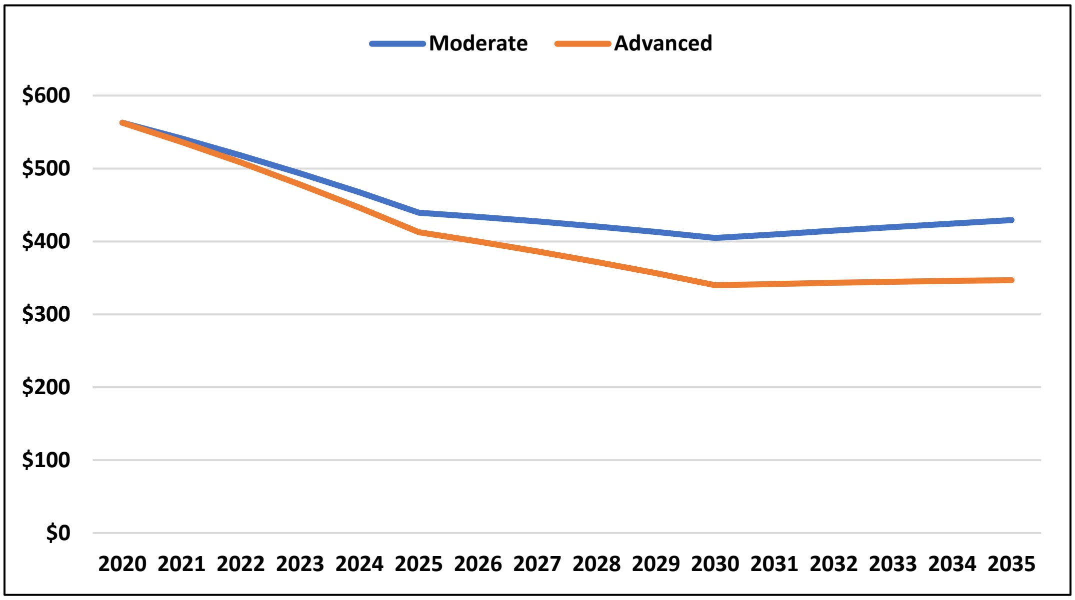
While a number of different battery chemistries are available for residential applications, lithium ion batteries are the most cost-competitive per cycle (a full charge and discharge) and were, therefore, the basis for our battery pricing assumptions.

Our 2020 starting point assumption, given this, was $563 per kWh.[26] To arrive at the battery-only capital costs per year, these prices were multiplied by the installed capacity of batteries in each year. We applied the ATB's Moderate and Advanced cost curves to our starting point

[26] Battery prices quoted in "per kWh" are not levelized over the total number of kWh discharged from the battery during its lifetime, but rather are the cost of the battery divided by the useable kWh provided by the battery in a single discharge.

assumption since residential batteries are also experiencing significant cost improvements and are expected to do so going forward (Figure 5).

Figure 5: Battery-Only Price Cases (Nominal $/kWh AC)



4.3. Transmission System

The power flow studies conducted by Telos identified reliability risk when periods of very high inverter-based generation are reached. Among the possible mitigations for this are the addition of synchronous condensers (SC).[27] If the technology progresses quickly enough, so-called "grid forming" inverters may also be able to mitigate the identified problems, so we did not include a cost of synchronous condensers. No other transmission related upgrades were identified in the Telos study.

4.4. Distribution System

The distribution system modeling performed by EE+ identified the mitigations in all scenarios that would be necessary to ensure stable and reliable operation. The mitigations shown in Table 3 are necessary in the Base Case and all DER scenarios.

[27] Synchronous condensers are essentially half a thermal power plant, they are a generator whose shaft is unconnected to anything and spins freely. Their function is to help provide essential grid services that mitigate reliability problems.

Table 3. Distribution Systems Mitigations Needed in Base Scenario

Region	Total Line Miles	Line Miles Reconductored	Line Miles Rebuilt	% Mitigation	Transformer Upgrades
Arecibo	4,790	13.7	315.9	6.9	0
Bayamon	2,442	81.7	106.6	7.7	0
Caguas	6,761	136.9	317.3	6.7	0
Carolina	3,310	100.7	140.8	7.3	0
Mayaguez	5,482	37.7	303.9	6.2	0
Ponce ES	2,828	12.1	127.7	4.9	0
Ponce OE	2,526	21.4	125.5	5.8	0
San Juan	2,908	29.1	95.2	4.3	0
Vieques	166	0.8	10.4	6.7	0
Culebra	68	1	2.4	5	0

Table 4 shows the additional mitigations that would be needed in order to accommodate the buildout of the 75% DER scenario.[28]

Table 4. Distribution Systems Mitigations Needed in 75% DER Scenario

Region	Total Line Miles	Line Miles Reconductored	Line Miles Rebuilt	% Mitigation	Transformer Upgrades
Arecibo	4,790	19	381.8	8.4	15
Bayamon	2,442	114.4	131	10.1	22
Caguas	6,761	191.6	384	8.5	30
Carolina	3,310	141	172.3	9.5	15
Mayaguez	5,482	52.7	365.7	7.7	18
Ponce ES	2,828	16.9	160	6.3	11
Ponce OE	2,526	26.8	177.3	8.1	10
San Juan	2,908	35	133.4	5.8	28
Vieques	166	1	14.5	9.3	0
Culebra	68	1.2	3.6	7.1	0

These mitigations are further described in the EE+ report.

To price out the cost of these mitigations we used data given to us by EE+ based on their experience upgrading distribution systems throughout North America. The distribution system presents a particular point of vulnerability for Puerto Rico, as it does for all electrical systems, so we added in a 20% hardening cost to address at least a portion of the hurricane risk to the system. The per unit upgrade costs are given in Table 5.

[28] Only one scenario was summarized in this report for brevity. The needed mitigations in each scenario are given in the EE+ report in the tables in Section V.

Table 5. Per Unit Distribution Mitigation Costs

Mitigation	Cost
Reconductoring	$94,556 per mile
Rebuilding	$157,594 per mile
Transformer Upgrade	$49,200 per MVA

These upgrade costs were then multiplied by the volume of mitigations needed in each scenario as described in the EE+ report.

4.5. Existing Thermal Generation

Three sources were used to estimate the cost of operating and maintaining (O&M) the existing fleet of thermal generation.

1. Telos study report [29]
   - Table 9 summarizes the fuel, variable O&M and startup costs in each of scenario; Base Case, 25% DER, 50% DER, and 75% DER.

2. PREPA IRP
   - The fixed O&M costs in $/kW-year were multiplied by the installed capacity, net of retirements, in the CAMBIO Study to estimate fixed O&M in each scenario.

3. Energy Information Administration (EIA)[30]
   - EIA commissioned a cost study in 2019 that characterized the cost of capitalized maintenance for different generating technologies by size and age. The cost estimates in $/kW-year were multiplied by the installed capacity, net of retirements, in each scenario to estimate capitalized maintenance.

Table 6 gives representative Fixed O&M (FOM) and capitalized maintenance (CAPEX) values assumed in this study.

[29] Puerto Rico DER Integration Study, Telos 2020, Table 9, page 26
[30] Generating Unit Annual Capital and Life Extension Costs Analysis, Sargent & Lundy, December 2019

Table 6: Thermal FOM and CAPEX Representative Values (2020$/kw-yr)

Case	FOM	CAPEX
Coal	$38.37	$22.55
Combined Cycle Gas	$25.99	$20.31
Oil/Gas Steam	$29.99	$9.69

To adjust fuel prices for the Advanced case we assumed a 40% decrease in prices from the Moderate case. Those results are shown in Section 5.6.

4.6. Carbon

The externality value of carbon dioxide emissions were priced using the Social Cost of Carbon ("SCC") from the EPA's Intergovernmental Working Group's (IWG) Central Estimate[31] at a 3% discount rate. The SCC is an externality value, meaning that it is an attempt to monetize the climate impact of greenhouse gases that are not regulated (internalized). Externality values like the SCC allow economic analyses like this one to explicitly account for the damage caused by greenhouse gases.

Table 7: Price of Carbon Emissions

Year of Emission	2020 $/Ton
2020	$69
2025	$76
2030	$81
2035	$87

The 2035 SCC cost was multiplied by the carbon emissions estimates from Telos' production cost modeling[32] to arrive at the cost of carbon emissions in 2035.

5. Scenario Cost Results

The results of the cost analysis for each major cost category appears in the following sections. First, we show the three primary system costs, solar PV, BESS and the distribution system upgrades using a levelization approach called a "economic carrying charge" (ECC). ECCs spread the total cost of a capital investment evenly across the lifetime of that investment and can be thought of as a mortgage payment. In order to create this levelized payment one must assume a discount rate. We use the two discount rates, 6.5% and 3.99%, described in Section 4.1, above.

[31] https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html

[32] Telos report, Table 8

5.1. Solar (PV)

The costs of solar PV appears in the following table. Because we assumed a lifetime for solar panels greater than 15 years the panels do not have to be replaced during the study period and so the results shown in Table 8 are the sum the "mortgage payment" associated with the installed solar. The term for this in the energy industry is "economic carrying charge" (ECC). Renewable costs are often recovered from customers as a levelized payment, so this is a reasonable approximation of the cost in rates in 2035. These costs are different than the total investment in PV assumed in this study which are given in Section 7.

Table 8: PV Cost Results (Millions of 2020$)

Price Case	Metric	Unit	25% DER	50% DER	75% DER
Moderate	ECC @ 6.5%	2020 $/Year	$145	$248	$354
	ECC @ 3.99%	2020 $/Year	$122	$224	$329
Advanced	ECC @ 6.5%	2020 $/Year	$134	$213	$295
	ECC @ 3.99%	2020 $/Year	$112	$190	$272

5.2. BESS

Like solar, these ECC values are the sum of the levelized costs of batteries installed through the period from 2021 to 2035. Because the batteries have a 14-year life, no replacement cost was assumed. These values do not represent the total investment need to realize any of the DER scenarios.

Table 9: BESS Cost Results (Millions of 2020$)

Price Case	Metric	Unit	25% DER	50% DER	75% DER
Moderate	ECC @ 6.5%	2020 $/Year	$145	$248	$354
	ECC @ 3.99%	2020 $/Year	$186	$262	$336
Advanced	ECC @ 6.5%	2020 $/Year	$182	$238	$292
	ECC @ 3.99%	2020 $/Year	$174	$237	$299

5.3. Distribution System

To calculate the ECC equivalent of the distribution system costs, we took the sum of the total costs of all mitigations and levelized that sum using the 6.5% and then 3.99% discount rates. Table **10** shows the cost per category of mitigations needed to enable the DER build out. Because the Base Case mitigations are additive to the DER scenarios, the DER scenario costs include the Base Case mitigations.

Table 10. Distribution Mitigation Costs by Scenario and Mitigation (2020$)

Scenario	Transformer Upgrade Cost	Reconductor Cost	Rebuild Cost	Total Cost
Base	$0	$41,141,424	$243,592,659	$284,734,084

25% DER	$0	$77,545,581	$455,887,200	$533,432,781
50% DER	$2,410,800	$76,269,071	$516,119,531	$594,799,403
75% DER	$7,330,800	$97,837,352	$546,739,997	$651,908,149

The cost includes a 20% adder for hardening based on a report by the World Bank[33] that estimates the hardening costs for a variety of power related infrastructure.

5.4. Thermal Operating Costs

The cost to operate the existing thermal generation fleet inclusive of fuel, variable O&M, fixed O&M, startup costs, and capitalized maintenance are shown in Table 11. The "Moderate" price case equates to the base case prices as modeled by Telos and the "Advanced" price case equates to a lower fuel price scenario, where fuel prices decrease by about 40%. The Advance case estimate was based on observed, historical volatility in oil and gas commodity prices. No volatility in coal pricing was assumed due to lack of data specific to Puerto Rico.

Table 11: Thermal Costs in 2035 (Millions of 2020$)

Price Case	Unit	Base Case	25% DER	50% DER	75% DER
Moderate	Millions of 2020 $	$1,341	$1,188	$883	$603
Advanced	Millions of 2020 $	$973	$819	$614	$431

All costs except the capitalized maintenance were derived from data from PREPA, primarily in its 2019 IRP and supporting workpapers. In order to account for at least an estimate of the cost of major maintenance associated with the thermal units we used a 2019 report prepared by Sargent & Lundy on behalf of the Energy Information Administration ("EIA").[34] Normally this type of maintenance would be capitalized, i.e. booked to rate base with a rate of return assigned to it. Conservatively, we assumed it was simply expensed to ratepayers.

Table **12** provides a breakdown of thermal costs by type and by scenario under Moderate case assumptions.

Table 12: Thermal Generation Costs at Mod. Prices (Millions of 2020$/yr)

Case	Base	25% DER	50% DER	75% DER
Fuel Costs	$1,003	$926	$677	$432
Fixed O&M + Cap. Maint.	$255	$198	$151	$130
Variable O&M	$59	$32	$21	$13
Startup Costs	$24	$31	$34	$28

[33] Miyamoto International. "Increasing Infrastructure Resilience Background Report." February 2019. Available at: http://documents1.worldbank.org/curated/en/474111560527161937/pdf/Final-Report.pdf
[34] U.S. Energy Information Administration. "Generating Unit Annual Capital and Life Extension Costs." December 2019. Available at: https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf

Total Costs	**$1,341**	**$1,188**	**$883**	**$603**

It is worth noting that virtually the entirety of the fuel costs in each scenario are exports of Puerto Rican dollars to off-island entities. This has been and remains a material point of price risk for Puerto Rico and for the stability of PREPA's rates.

5.5. Carbon Costs

As with the thermal operating costs in the previous section, the cost of carbon emissions is expressed in 2020 dollars. Carbon dioxide emissions are priced at the Social Cost of Carbon mid-point trajectory as determined by the Environmental Protection Agency's Intergovernmental Working Group.

Table 13: CO_2 Emissions Cost (Millions of 2020 $/yr)

Metric	Unit	Base Case	25% DER	50% DER	75% DER
Emissions Cost	2020 $/Year	$729	$476	$339	$215

5.6. Total Costs

The total cost to operate the system under each scenario is the sum of annual operating and carrying (levelized) costs for all five cost categories: PV, BESS, distribution system, thermal operating costs and carbon costs. The sum of these costs appears in the following two tables using each of the two discount rates used throughout this report.

Table 14: Total Cost Results at 6.5% Discount Rate (Millions of 2020 $/yr)

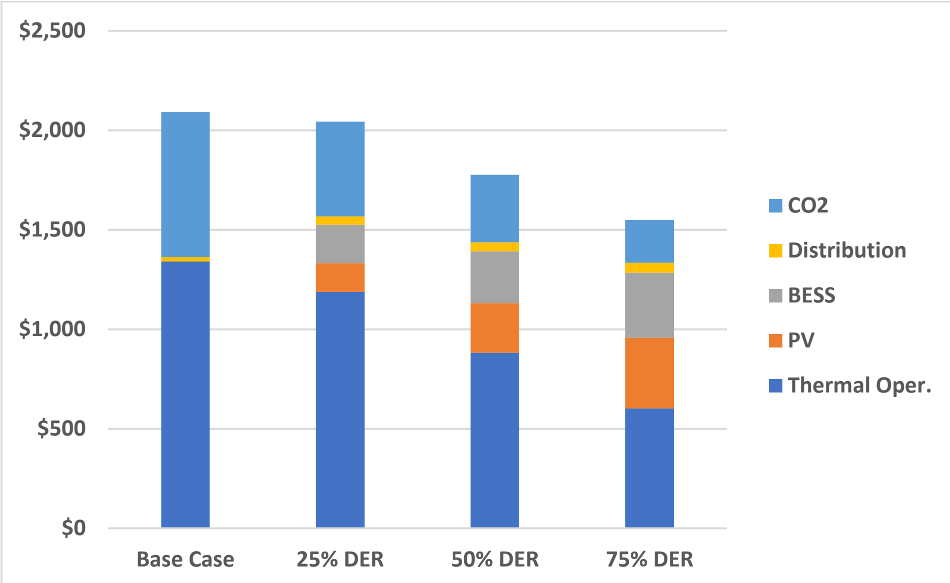
Metric	Unit	Base Case	25% DER	50% DER	75% DER
Moderate	$/Year	$2,091	$2,043	$1,776	$1,549
Advanced	$/Year	$1,724	$1,651	$1,448	$1,284

Table 15: Total Cost Results at 3.99% Discount Rate (Millions of 2020 $/yr)

Metric	Unit	Base Case	25% DER	50% DER	75% DER
Moderate	$/Year	$2,086	$2,002	$1,742	$1,521
Advanced	$/Year	$1,718	$1,612	$1,414	$1,255

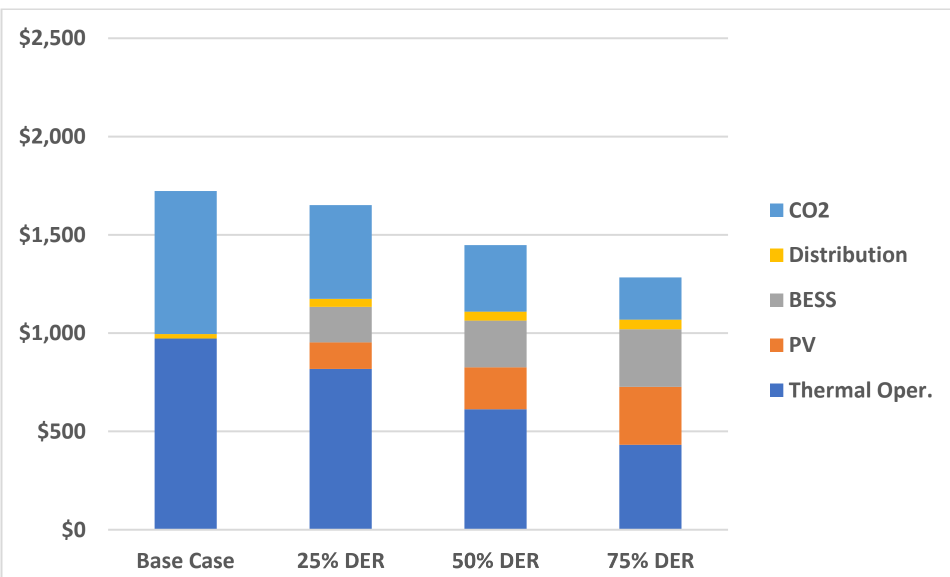
The following figure combines all of the annual costs into a single chart by cost category under Moderate pricing assumptions. Total system costs in the Base case and 25% DER scenario are very similar. Costs are much lower in the 50% and 75% DER scenarios because of the increasing utilization of lower cost solar in the commercial and industrial sectors, because of larger displacement of oil-fired generation (the highest cost fuel), and because of the decreasing magnitude of carbon dioxide externalities relative to the other scenarios.

Figure 6: Total Operating & Carrying Costs with Moderate Prices at 6.5% (Millions of 2020$)



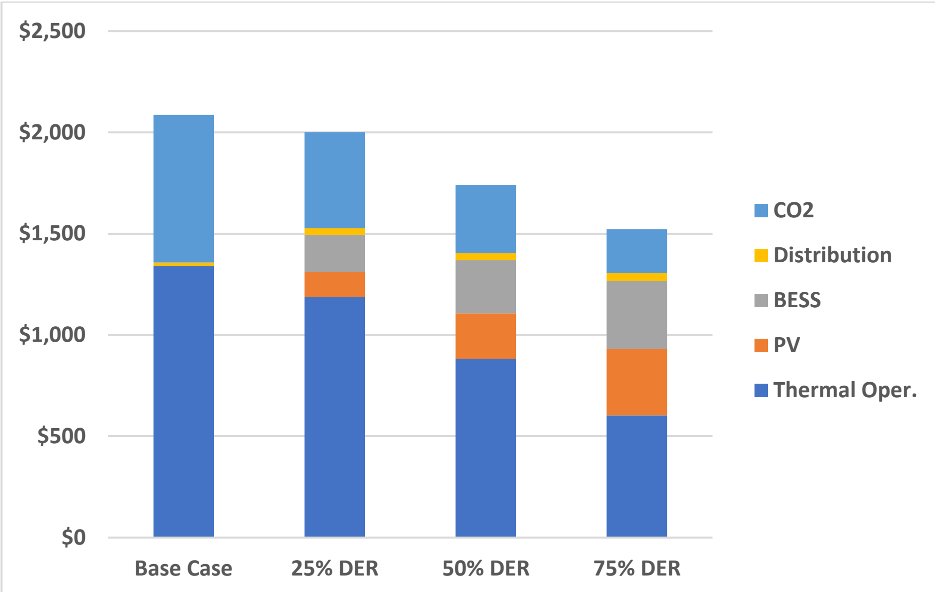
The relative cost dynamic of the scenarios is little changed under Advanced case pricing. PV and BESS capital costs decline, but so do fuel costs and because those predominate in the Base Case its overall cost is greatly reduced as well.

Figure 7. Total Operating & Carrying Costs with Advanced Prices at 6.5% (Millions of 2020$)



These results look similar under the alternative discount rate assumption of 3.99% as shown in Figure 8. The 75% DER Scenario is very clearly preferable over the Base Case. And the same is true for the 25% and 50% DER Scenarios.

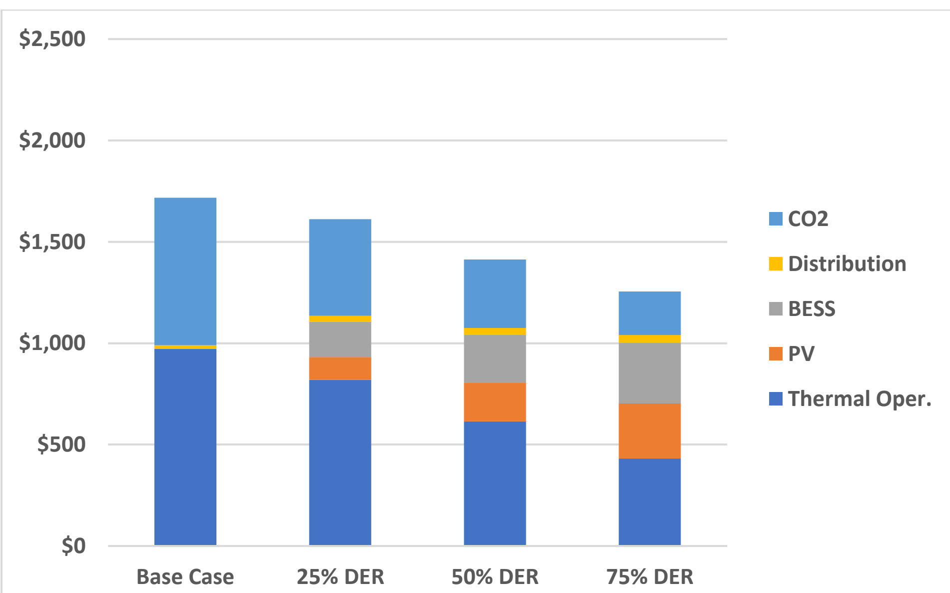
Figure 8. Total Operating and Carrying Costs with Moderate Prices at 3.99% (Millions of 2020$)



This result is simply the product of a changed assumption about the time value of money from 6.5% to 3.99%.

Similarly, under Advanced pricing assumptions, the DER Scenarios look much more preferable relative to the Base Case.

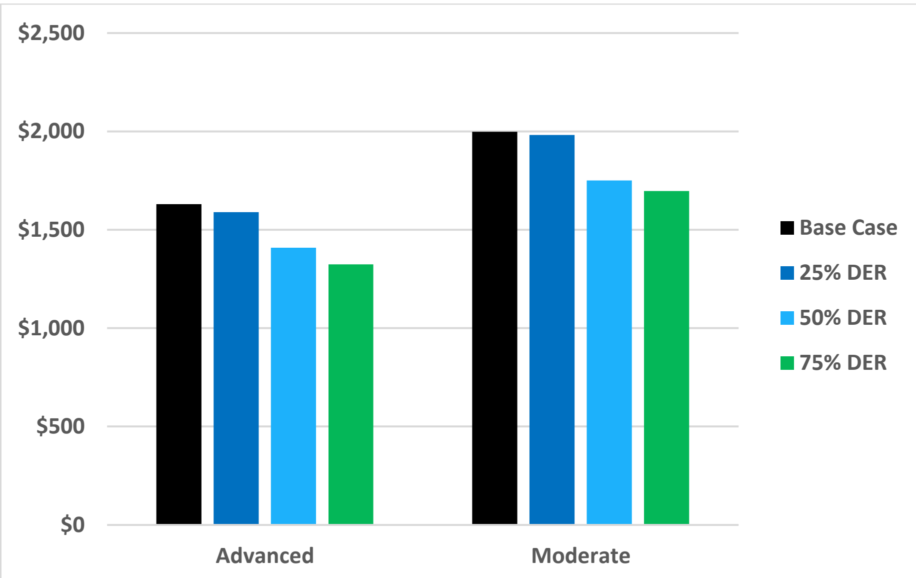
Figure 9. Total Operating and Carrying Costs with Advance Prices at 3.99% (Millions of 2020$)



6. Sensitivity Results

Telos also ran two sensitivities examining the impacts of imposing a minimum inertia constraint and synchronous ratio to ensure system reliability under current operational conditions. These constraints served to keep additional thermal generation online (though it did not change retirements). The net effect is to increase system cost, particularly in the 75% DER scenario which, but for the inertia constraint, would have had significantly more hours of 100% inverter-based generation.

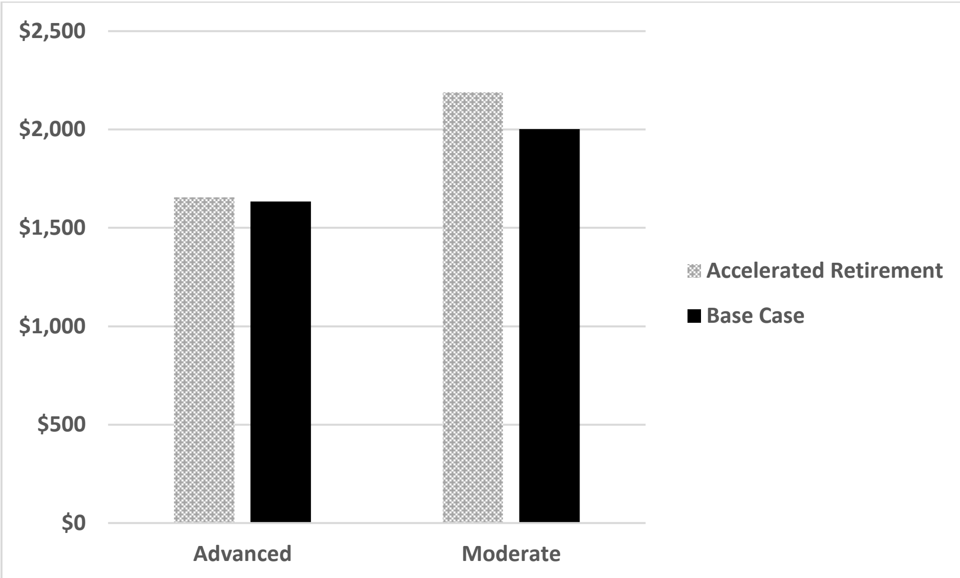
Figure 10. Total Operating & Carrying Costs Under Grid Stability Sensitivity (Millions 2020$)



This sensitivity eliminates a significant portion of the benefit of the 75% DER scenario, i.e, reduced oil spending. The higher DER scenarios still contain the same level of PV and BESS investment, but require more fuel in order to satisfy the minimum inertia and synchronous ratio constraints. Even so, the 75% DER scenario was still significantly cheaper than the Base Case.

We also looked at a second sensitivity exploring early retirement of AES (Figure 11). This sensitivity examined PREPA's grid in 2024 assuming that the AES units had been retired. Under Moderate case assumptions early retirement is slightly more expensive than the Base Case which includes the AES units. This result is largely expected because the Base Case makes no assumptions about additional costs to mitigate coal ash disposal and other environmental burdens imposed by the AES units (beyond pricing its carbon dioxide related externalities). Under Advanced Case assumptions, retirement is even in cost with a cleaner portfolios of resources.

Figure 11. Total Operating & Carrying Costs Under AES Accelerated Retirement Sensitivity (Millions 2020$)



7. Comparison to 2019 PREPA IRP

At the time that we began this analysis the outcome of PREPA's 2019 IRP was uncertain. The case was awaiting an order from the Puerto Rico Energy Bureau and there was, therefore, no clarity on whether the Bureau would adopt PREPA's preferred plan in that IRP – the so-called Energy System Modernization ("ESM") plan or rule on a different plan altogether. Rather than compare the DER scenarios to a plan that may be out of date by the time the analysis was completed, we chose to compare the DER scenarios to the system as it existed at the start of 2020.

While our results may not be fully comparable to PREPA's 2019 IRP because of differing assumptions about load and the fact that we are simulating only 2035 rather than the full IRP planning period of 2019 - 2038, there is still a useful comparison that can be made – between the total generation and transmission investment under the ESM plan versus the DER scenarios.

That investment is summarized in Figure 12, below.

Figure 12. Total Capital Investment, 2020 – 2035

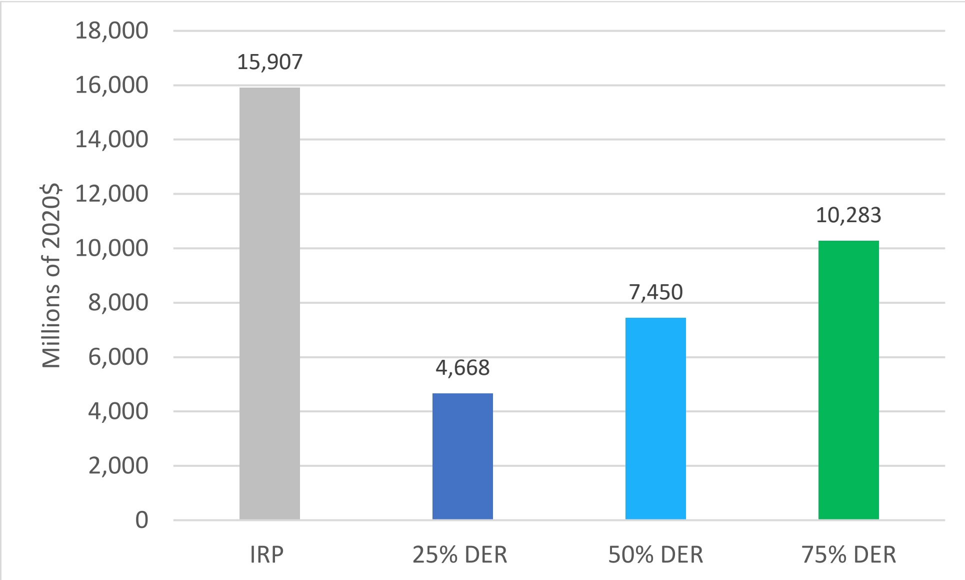
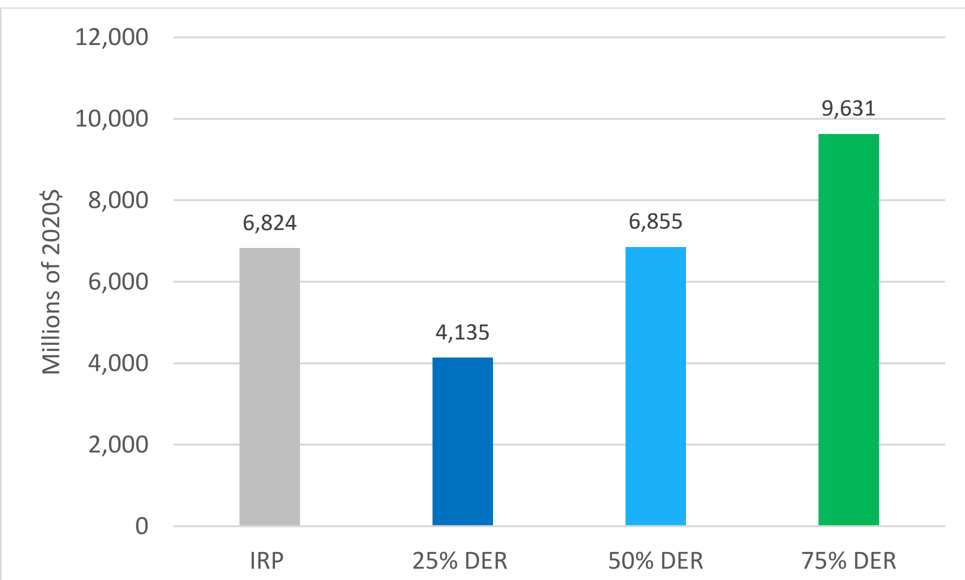


Figure 13 and Figure ***14*** show the capital investment given in Figure 12 broken down between generation and transmission and distribution expenditures.

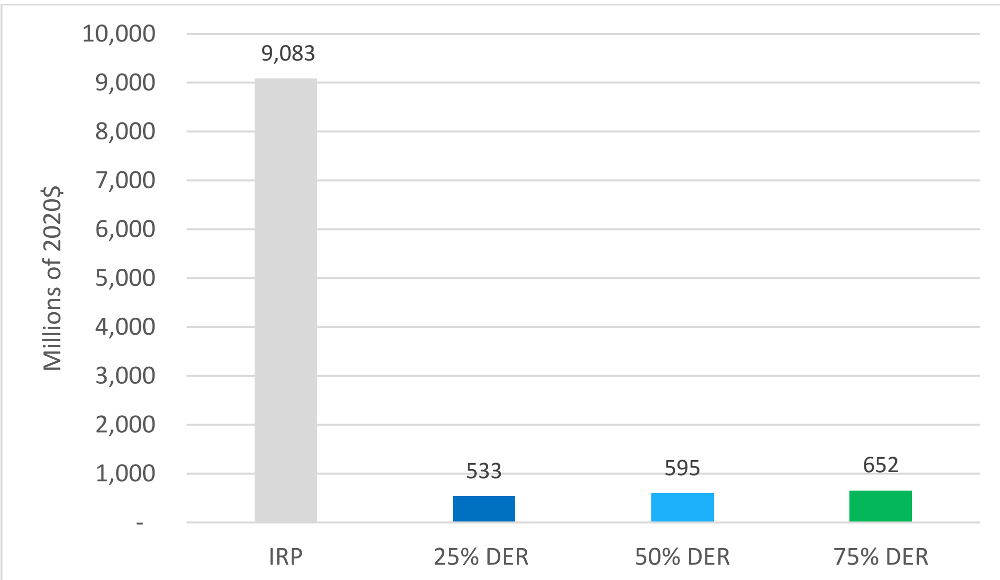
Figure 13. Total Generation Investment, 2020 – 2035



IRP total generation investment does not include the 848 MW of distributed solar by 2035 that was included in the ESM. It is solely the product of utility scale solar, battery storage, and gas assets that were proposed as part of the ESM. For that reason alone, the $6.824 billion of generation investment in the IRP is understated in comparison to the DER scenarios. Either way it makes sense that the DER scenarios would have more generation investment because they are predominantly served by fuel-less power plants and therefore more cost goes into capital than into fuel and operating expenses.

The opposite is the case when comparing total transmission and distribution investment in the IRP to the identified investment in the DER scenarios (Figure 14). Total transmission and distribution investment dwarfs that identified in EE+'s modeling. There are several reasons for this.

Figure 14. Total Transmission and Distribution Investment

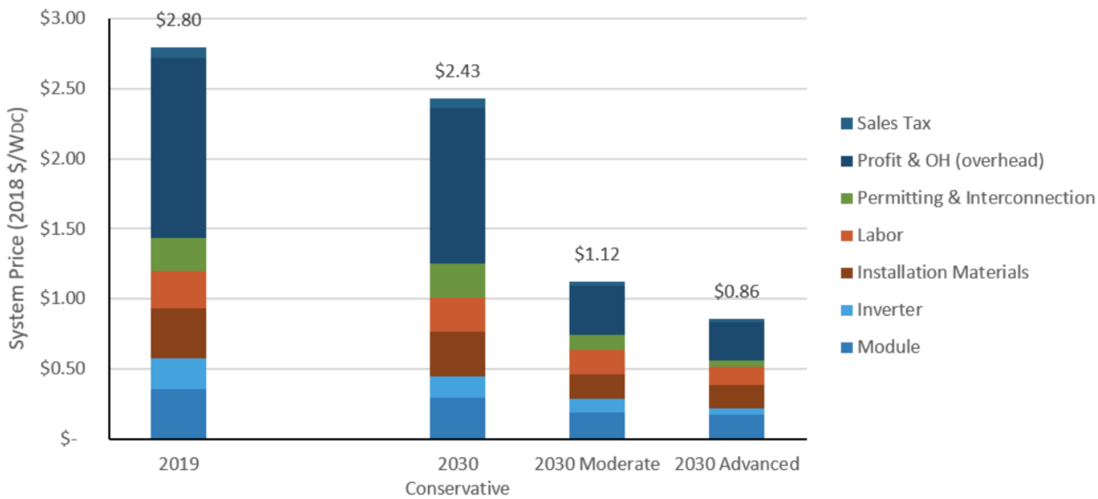


First, the minigrid/microgrid component of the ESM was very costly – at least $5 billion was devoted to that purpose alone. Second, at least $3 billion of the proposed IRP T&D investment was to address hardening and aging in existing infrastructure. Our study can provide no insight into those expenditures because, as described in their report, EE+ had to extrapolate the seven representative circuits provided by PREPA across the entire island. Therefore, EE+ lacked the data to assess the existing condition of distribution system assets. We cannot conclude, therefore that all or a portion of the $3+ billion in aging and hardening expenditures would be needed (or not) in any future scenario. Even if $3 billion in aging and hardening expenditures needed to be added to all scenarios we evaluated, distribution system costs would still be over $5 billion lower than those proposed as part of the ESM. We believe this raises substantial questions about the merits of PREPA's minigrid/microgrid concept as the least cost way to deliver resiliency to Puerto Rico's grid.

8. Opportunities to Lower Total System Costs

Achieving the 75% DER scenario in particular will take concerted and robust policy and regulatory steps. The manner in which the PV and BESS are deployed can also influence the ability to achieve this goal and total system cost. Targeted deployment that installs rooftop systems by neighborhood, for example, could likely reduce cost. A similar approach was used in the Netherland's Energiesprong housing retrofit program. Within four years of starting the program per unit cost had been reduced by 60%.[35] We do not know what magnitude of cost reductions is likely to be achievable for a similar program focused on the buildout of rooftop solar, but we believe is very reasonable to think cost reductions would be had.

Figure 15. Breakdown of Residential Solar Cost Components[36]



The 2020 ATB included NREL's projection of residential solar prices by cost component. Figure 15 clearly shows that there are significant "soft costs" embedded in current solar prices and to the extent that policy tools can be used to remove profit and overhead for example, near-term costs could come down even further.

Finally, there is a significant opportunity for Puerto Rico to offset the cost of deploying the solar and battery storage buildouts in this study by leveraging federal funding. A Community Development Block Grant – Disaster Recovery (CDBG-DR) grant of over $1.5 billion has been allocated to Puerto Rico. At least a portion of those funds are to be directed to the Community Energy and Water Resilience Installations Program which will provide single family homeowners, business and/or public facilities energy and water efficiency improvements to promote resilience with the installation of PV systems with battery back-up for critical loads and water storage system. Additionally, FEMA has allocated over $10 billion for the rebuilding and upgrading of Puerto Rico's electrical system. Those funds are essentially unconstrained and can and should be used to invest in generation that will improve system reliability and resiliency rather than further cementing Puerto Rico's centralized generation model.

[35] https://sbcanada.org/wp-content/uploads/2017/09/Energiesprong-Summary-Report.pdf

[36] Taken from NREL 2020 ATB: https://atb.nrel.gov/electricity/2020/index.php?t=sr

9. Conclusions

The project team members on this study engaged in a detailed and complex set of analyses to simulate Puerto Rico's electric grid under high DER penetration. After many months of effort we conclude that a system predominately served by distributed solar is feasible, achievable, and very likely to reduce overall system costs. Among our primary findings are the following:

1. All the DER scenarios were either comparable to or much less costly than a business-as-usual case.
2. More DER also enables Puerto Rico to realize more of the benefits of reduced fuel consumption because greater quantities of oil generation are offset.
3. Under a business-as-usual scenario (Base Case), Puerto Rico would expend $1 billion a year to primarily foreign entities on fuel alone. With load served by 75% DERs those expenditures are more than halved.
4. It is important that Puerto Rico chart a path (and soon) to realizing the benefits of energy efficiency as a way to provide further rate stability and electric bill reductions to all Puerto Ricans.
5. Technologies under development such as smart inverters will be key to unlocking the full economic benefits of the high DER scenarios analyzed here.
6. This study made no attempt to monetize the considerable value of increased reliability or the ability of millions of Puerto Ricans to self-supply at least their critical loads in the event of another hurricane.