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**COMMONWEALTH OF PUERTO RICO**
**PUBLIC SERVICE REGULATORY BOARD**
**PUERTO RICO ENERGY BUREAU**

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| IN RE: REVIEW OF THE PUERTO RICO ELECTRIC POWER AUTHORITY INTEGRATED RESOURCE PLAN | **No.** CEPR-AP-2018-0001<br><br>**SUBJECT:** PREPA's Motion for a Limited Extension of Time |

## THE PUERTO RICO ELECTRIC POWER AUTHORITY'S MOTION FOR A LIMITED EXTENSION OF TIME

TO THE HONORABLE PUERTO RICO ENERGY BUREAU:

COMES NOW the Puerto Rico Electric Power Authority ("PREPA") and respectfully moves that the Puerto Rico Energy Bureau (the "Energy Bureau")1, extend, for a limited period, until February 12, 2019, the due date for PREPA's completion of the submission of its Integrated Resource Plan ("IRP") filing. In support of its Motion, PREPA states as follows:

1. In the Energy Bureau's November 6, 2018, Order, the Energy Bureau ordered PREPA to file its IRP filing by January 21, 2019.[2]

2. In brief, the IRP *analysis*, under the Energy Bureau's Regulation No. 9021 and the Bureau's many orders, such as the Bureau's order of November 8, 2018, and its orders of November 21 and 28, 2018, in case no. CEPR-AI-2018-0001 (requiring certain IRP analysis relating to San Juan units 5 and 6, and clarifying that requirement,

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[1] References herein to the Energy Bureau include the former Puerto Rico Energy Commission when applicable.

[2] Because January 21, 2019, was a Commonwealth of Puerto Rico public holiday, this Motion is being filed on the next business day.

respectively), is a very extensive and complicated analysis that takes months to perform in a proper and compliant manner.

3. In brief, the IRP *filing*, under Regulation No. 9021, includes the extensive write-up of the IRP analysis, work papers, direct testimony (with attestations and possibly other attachments), and any required motions such as motions for protection of confidential information like Critical Energy Infrastructure Information and for waiver of any requirements.

4. For many months, PREPA has been working diligently with Siemens Power Technologies International ("Siemens") to prepare the IRP analysis and the IRP filing. The IRP's development also has included extensive stakeholder processes and interaction and cooperation with the Energy Bureau and its staff through filings and technical conferences as well as Bureau orders.

5. However, despite those diligent efforts, while a majority of the IRP analysis has been performed, some of the analysis and much of the write-up is not yet performed or drafted, respectively. Moreover, the required Action Plan is not yet finalized, in part because finalization of the Action Plan is an iterative process with the IRP analysis. The final assembly of work papers is dependent upon finalization of the IRP analysis. Similarly, the substance of direct testimony and finalization of motions also is dependent on the finalization of the IRP analysis and of the IRP write-up and work papers.

6. PREPA and Siemens have carefully considered whether filing some portions of the IRP filing today would be appropriate and useful, and have concluded that the answer is yes, subject to the very important qualification that, as they finalize the

remainder of the IRP analysis and filing, there is a possibility that some of the materials to be filed today will require updating, revision, and/or correction. Accordingly, PREPA is filing some materials today and will provide an accompanying list of those materials.

7. Please note that some of the materials are being designated as confidential, so they will exist in both confidential "Bureau and Bureau staff eyes only" format and public redacted format.

8. Accordingly, PREPA, in this motion, now respectfully requests that the Energy Bureau extend for a limited period, until February 12, 2019, the due date for completion of the submission of the IRP filing. PREPA has chosen the proposed February 12 date based on careful consideration of the remaining tasks, with the intention of avoiding any further motion for an extension of time.

9. PREPA also asks that discovery not be allowed to commence until after PREPA has completed the IRP filing. Discovery before then would be inefficient and would be likely to seriously impede completion of the filing.

10. With this filing, PREPA will be submitting the following documents:

a. Main Body of IRP Filing, Parts One to Eight

b. Technical Appendix 1 (Confidential) - Partial

c. Technical Appendices 3, 4, and 5

11. PREPA requests that Technical Appendix 1, Transmission and Distribution Planning, be designated as Confidential, since it contains Critical Electrical Infrastructure Information.

WHEREFORE, for the reasons stated above, the Puerto Rico Electric Power Authority respectfully requests that the honorable Puerto Rico Energy Bureau extend the deadline for completion of the submission of PREPA's Integrated Resource Plan filing to February 12, 2019.

RESPECTFULLY SUBMITTED,

IN SAN JUAN, PUERTO RICO, THIS 22nd DAY OF JANUARY, 2019

**PUERTO RICO ELECTRIC POWER AUTHORITY**

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## CERTIFICATION OF FILING AND SERVICE

I HEREBY CERTIFY that, on January 23, 2019, I have filed the foregoing Motion with the Puerto Rico Energy Bureau in hard copy format at the office of the Clerk of the Puerto Rico Energy Bureau, at the Seaborne Building Plaza (old World Plaza Building), 268 Munoz Rivera Avenue, Plaza Level, Suite 202, San Juan, Puerto Rico, 00918; and, further, at approximately the same time, that the Motion was sent to the Puerto Rico Energy Bureau via email to secretaria@energia.pr.gov and mcintron@energia.pr.gov, to the office of the Energy Bureau's internal legal counsel via email to legal@energia.pr.gov and sugarte@energia.pr.gov.

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** DRAFT ** **Siemens PTI Report Number: RPT-001-19**

# *Puerto Rico Integrated Resource Plan 2018-2019*

## Draft for the Review of the Puerto Rico Energy Bureau

Prepared for

## **Puerto Rico Electric Power Authority**

Submitted by:
Siemens Industry

Rev. [0]
1/22/2019

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v16

**Revision History**

| Date | Rev. | Description |
|---|---|---|
| 1/22/2019 | 0 | Initial draft |

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# Legal Notice

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Part

1

# Introduction and Summary of Conclusions

## 1.1 Introduction

Following the massive destruction resulting from Hurricanes Irma and María in 2017, Puerto Rico faced the unprecedented challenge of rebuilding their electric power system. The hurricanes forced the Puerto Rico Electric Power Authority (PREPA) to rethink how its power supply and delivery infrastructure should be modified to ensure that the utility infrastructure was much better prepared for future weather events. In addition, PREPA's current fiscal situation as a debtor under the Title III of the Puerto Rico Oversight, Management, and Economic Stability Act (PROMESA) requires it to identify a roadmap for the electrical system infrastructure that will support its path to comply with healthy financial utility practices.

An essential tool to develop a plan that would realize these goals was to develop an Integrated Resource Plan (IRP). PREPA is required, under Puerto Rico Act 57 of May 27, 2014 (Act 57-2014), as amended, to prepare an IRP which shall consist of a detailed planning process considering all reasonable resources for satisfying the demand for electrical services in Puerto Rico over a twenty (20) year planning horizon, including resources related to energy supply and demand. In addition, the IRP shall consider resiliency, reliability, and stability of the power system, including full compliance with current and future environmental regulations.

This document and associated appendices present PREPA's 2019 IRP, which provides the analysis and recommendations for PREPA's energy supply resources for a 20 year period (2019 to 2038). The parts and appendices of this document are intended to fulfill the requirements of the Puerto Rico Energy Bureau (PREB) Regulation 9021, Regulation on Integrated Resource Plan for the Puerto Rico Electric Power Authority (IRP Regulation). The IRP was developed by Siemens Power Technology Inc. (Siemens) using a rigorous analytical process. The IRP analyses considered a large number of options and uncertainties, taking into consideration formal and informal input from both PREPA and a large number of stakeholders.

The IRP recommendations are fully aligned and support the five key pillars adopted by the PREPA Governing Board in its Vision for the Future of Power in Puerto Rico (the original, complete text describing these pillars is provided in Exhibit 2-2; Siemens summary is provided below):

1. **Customer-centric:** The IRP includes costumer participation via energy efficiency, customer side energy resources and demand response with a predominant role in

the supply and consumption matrix of Puerto Rico, and empowering customers to participate and take ownership on their energy security and affordability.

2. **Financial Viability:** Within the requirements of resiliency and reliability, the plan minimizes the cost of supply and drastically reduces the dependence on imported fuels and the associated volatility; thus, supporting affordable rates that promote financial viability at both sides of the meter.

3. **Reliable and Resilient**: The IRP is centered on the concept of MiniGrids, which are defined as zones of resiliency into which the system can be segregated during and after a major storm or weather event ensuring that the load can be served using local resources and supporting the effective and timely recovery from the event.

4. **Model of Sustainability:** The IRP's implementation will transition the Puerto Rico electric system from one centered on fossil fuels to one in which the renewable resources play a central, if not, the predominant role. The IRP's implementation will drastically reduce emissions, increase the penetration of renewable generation, achieve compliance with all current regulations, and position Puerto Rico for future regulations.

5. **Economic Growth Engine:** The distributed nature of the new generation resources that will have to be developed, the high levels of customer participation on the energy production and the overall reduction in the system cost are expected to result in employment opportunities and economic growth for Puerto Rico. The IRP will support a reliable and economic system that will attract economic development in Puerto Rico.

The 2019 IRP is not a classical IRP designed to identify the least cost approach to address the expected gap between future load growth and resources while maintaining a desired Planning Reserve Margin (PRM). Rather, this plan must satisfy the five pillars stated above for a system with declining load. The load served by the PREPA is expected to significantly decline over the course of this IRP's planning horizon due to a combination of expected base load reduction (driven by population and economic changes), energy efficiency gains, and demand side resources. Instead of new resources to meet load growth, this IRP is designed instead, to address the following needs:

a) Address the impacts of an aging generation fleet that burns costly liquid fuels (mostly heavy fuel oil), that does not meet environmental regulations (e.g. MATS), has poor reliability, and is inflexible, which limits the incorporation of renewable resources.

b) Achieve a reduction of cost of supply by the incorporation of renewable resources for which the current and forecasted costs should provide continued savings.

c) Achieve compliance with the Renewable Portfolio Standard (RPS) mandate. However, Siemens observed that the renewable cost benefits alone justified greater levels of penetration and, consequently, making possible to comply with the RPS.

d) Shift from centralized generation located in the south of the island to more decentralized generation resources distributed across the island.

In developing this IRP, Siemens worked with PREPA and the PREB to identify five scenarios deemed worthy of analysis:

**Scenario 1 -** No new natural gas (gas) delivery infrastructure added combined with expected (base case) cost of renewable and availability,

**Scenario 2 -** Gas delivery is made available only in the north combined with expected (base case) cost of renewable and availability (this scenario was dropped after the first screening),

**Scenario 3 -** Gas is made available at multiple, new LNG terminals (north, east and west locations) combined with further reduction in the cost of renewable and higher renewable availability,

**Scenario 4 -** Gas is made available at multiple, new LNG terminals (north, east and west locations) combined with expected (base case) cost of renewable and availability, and

**Scenario 5 -** Similar to Scenario 4, but with the Aguirre Offshore Gas Port as an option, larger combined cycle units and centralized Strategy 1, as described below.

In addition to the five scenarios above, a sixth scenario, the Energy System Modernization (ESM) plan was considered. This is a plan advanced by PREPA and includes a set of pre-defined investments decisions formulated based on PREPA's advisors experience and considering its ongoing Request for Proposals (RFP) processes for new resources. The ESM was analyzed and compared on an equal footing with the other five scenarios described above.

The Scenarios above were combined with one or more of the three different resource strategies:

**Strategy 1 -** Reflects a traditional, centralized energy program with generation resources predominately located at a few centralized locations emphasizing reliability and economic metrics.

**Strategy 2 -** Reflects a system of more distributed, flexible generation, emphasizing resiliency and closer proximity of generation sources to the customer. The strategy incorporates micro or mini-grids and hardening of existing PREPA infrastructure. In this strategy, most of the load is supplied from local supply resources that can be isolated from the remainder of the grid during a major event, but still supply all or a portion of the nearby load.

**Strategy 3 -** Reflects a hybrid of the first two strategies that embodies a combination of the benefits of Strategy 1 and Strategy 2. In this strategy, economies of scale are considered, which results in some of the load potentially served, under normal conditions, from remote resources. During a major event, the potential for greater levels of rotating load shed in this strategy is greater than with Strategy 2, but should also result in lower operating costs.

Siemens combined scenarios and strategies to define the structure under which candidate portfolios of resources were assessed. To these combinations of scenarios and strategies, Siemens added assessment of high, base and low load forecasts and several sensitivities were considered (e.g. high gas prices, high/low cost of renewable, etc.). Part 5 - Resource Needs Assessment, of this document, provides further details on the complete range of analysis.

In the development of the IRP, over 78 Long Term Capacity Expansion (LTCE) plans were investigated to assess plausible options and numerous uncertainties, taking into account stakeholder input. These points were critical for the final product and included multiple aspects, for example: a) the timing of investments in traditional thermal generation units, b) practical limits to the ability of PREPA to effectively interconnect additional battery energy storage and renewables generation, c) uncertainty associated with fuel price forecasts and infrastructure options, d) uncertainty associated with the customer demand forecast, and d) assessment of resource candidates provided by PREPA's management and the Puerto Rico Public-Private Partnership Authority (P3). As detailed in Part 7 – Assumptions and Forecasts, this effort resulted in the identification of a final set of 32 LTCE plans that were assessed to identify the recommended resource plan with a primary focus on the next 5 years, while also considering the long-term planning horizon of 20 years. Part 8 – Resource Plan Development of this IRP provides the details of assessment and inputs of the 32 LTCE plans. A summary of the input conditions of the 32 LTCE plans are provided in Exhibit 1-1.

In the next section we provide a summary of Siemens conclusions and recommendations based on the consideration of all scenarios and all strategies to develop the 32 LTCE plan and identifying common elements among them to define the minimum regret or no regret decisions (i.e., the decision that would provide the best possible solution over the broadest range of potential future conditions). Appendix 1 – Transmission and Distribution Planning provides the details on the transmission expansion plans associated with the generation resource options.

This IRP is a recommended plan for PREPA and Puerto Rico. The IRP does not address the details of procurement, interconnection, ownership, rate structures, nor the issues associated with PREPA's debt or privatization plans. All of these other important issues will need to be addressed in other processes and venues, and later combined with this IRP to develop a complete roadmap for Puerto Rico's power system.

## 1.2 Summary of Conclusions and Recommendations

The conclusions and minimum regret or no regret recommendations of this IRP include integrating the maximum amount of renewable generation that is practical to interconnect in the first four years of the planning period, adding distributed resources and hardening the transmission and distribution grid so that it can be segregated into eight largely self-sufficient electric islands (MiniGrids). This is essential in order to mitigate, manage and enable timely recovery from a major storm, while shifting the traditional generation from largely heavy fuel oil and distillate fuels to cleaner natural gas. The following list provides an overall summary of conclusions and recommendations.

## *A. Supply Side Decisions and Conclusions*

1- ***Maximize the rate of installation of solar photovoltaic (PV) generation for the first 4 years (2019 to 2022) of the plan***: The recommendation is to issue requests for proposals (RFP) in blocks of approximately 250 MW, and depending on pricing and PREPA's capability to interconnect, continue adding blocks with a goal of interconnecting at least 750 MW and possibly 1,200 MW over this period. The RFP should account for PREPA's expected capability to interconnect the renewable, which will be a function of the size and number of projects and it will be unknown until responses are received. In all but one LTCE plan analyzed, the installation of PV reaches the maximum allowed capacities as defined to account for an aggressive practical implementation limit for the first 4 years on the plan. The one exception is the case where the costs of renewable generation do not drop in Puerto Rico and, in this single case, only 750 MW of renewable generation is added to the system over these years. Also, in Scenario 3, which has largely unconstrained limits on PREPA's ability to interconnect new renewable generation and has even lower prices of renewable, 1,500 MW of PV are installed. It should be noted that the interconnection of these amounts of PV generation, in such a short time, is a very aggressive approach for an isolated power system.

2- ***Install between 500 to 1,100 MW of Battery Energy Storage in the first 4 years of the plan:*** The amounts of battery energy storage are heavily correlated with the total amounts of PV to be installed and the local energy supply required for the MiniGrids into which the system is expected to segregate during major events. For instance, the minimum amounts of BESS observed are 440 MW for the ESM plan and 800 to 1,100 MW for the Scenario 4 and Strategy 2 (designation as S4S2) depending on the load growth. Scenario 1 with no new gas and Scenario 3 have similar levels to those observed for high load of Scenario 4 (1,240 MW max).

   It is recommended that storage be added to the RFPs for renewables presented above, in blocks of 150 to 200 MW. Siemens also recommends that the RFPs for storage be combined with the RFPs for PV with the option of bidders providing either or both of these technologies. The combined RFPs give the developers the opportunity to co-locate the storage with PV and gain advantages of sharing equipment, including the inverters.

3- ***Convert San Juan 5&6 Combined Cycle (CC) to burn natural gas***: This option is a currently ongoing initiative using a ship-based liquefied natural gas (LNG) terminal and was adopted as a given in the formulation of all plans where there is new gas development (all scenarios but Scenario 1). However, initial runs of the LTCE early in the project had already identified this option as a least cost alternative (i.e. it was selected by the optimization process).

4- ***Develop a land-based LNG terminal in San Juan to supply a new combined cycle gas turbine (CCGT) and San Juan 5&6 Combined Cycle***: This decision is selected every time in the LTCEs, with the exception of the case where it was assumed the LNG terminal could not be developed for external reasons (Scenario 1). The CC was limited to a smaller unit (F-Class representative unit) or about 300 MW, to limit the size of the largest unit in the system. Larger units (e.g. an H-Class of about 450 MW) were selected by the LTCE runs if allowed. However, the CCGT size was limited to reduce the exposure to large unit trips. This new CCGT should be in place as soon as practical (2025 was assumed in this study).

5- ***Install a CCGT at Costa Sur Steam Plant or extend a renegotiated contract with EcoEléctrica:*** Under all cases, unless the contract with EcoEléctrica is renegotiated to significantly reduce the fixed payments and the plant is allowed to cycle frequently, EcoEléctrica is replaced by a 300 MW CCGT after the contract expires in 2022. The analysis assumes the new CCGT can be built in 2025. Due to the inability of installing gas generation elsewhere in the system, Scenario 1 installs two or even three F-Class CCGT here over time, depending on the load.

6- ***Install new Gas Turbines (GTs) capable of burning containerized natural gas:*** The need to serve critical and priority loads within the MiniGrids for resiliency resulted in the necessity to add 17 to 18 small gas turbines (each of 23 MW) at selected locations in the grid; specifically Caguas (Yabucoa) - 5 units, Carolina (Daguao) - 5 units, Cayey - 2 units, Ponce East (Jobos) - 2 units, and Mayagüez North (Aguadilla) - 2 units, among others. Siemens found the beneficial savings of not installing these small distributed gas turbines was significantly smaller than the potential costs to the economy should another large hurricane strike Puerto Rico and the MiniGrids were forced to operate in isolated mode for a month. In the assessment, Siemens included all the resources available to the MiniGrid including the PV and storage in addition to the GTs. These small GTs should be placed in service as soon as practical (2021 is assumed as the earliest commercial operation date).

7- ***Develop a Ship-Based LNG terminal at Mayagüez:*** Developing a new LNG import terminal at Mayagüez is the least cost solution under most cases, with the exception of cases that one of the following apply: a) have very low cost of renewables, b) no new gas can be developed, c) low load growth, or d) the LNG in the North is limited to the ship-based delivery (in which case the Yabucoa terminal below is developed). Under the balance of the scenarios, including the Scenario 4 Strategy 2 (S4S4), a 300 MW CCGT is recommended by 2028 under the base and high load forecast. Under the ESM plan, the aeroderivative gas turbines (Aero) installed at Mayagüez are converted to natural gas only. The recommendation is to advance the development of this option with the view of at least converting the existing units to burn LNG initially and then develop a larger CCGT plant as the load and prices of renewables require. This CCGT should be installed by 2028 unless the cost of renewables are high, in which case the installation of the CCGT should be earlier (2025 assumed).

8- ***Develop a Ship-Based LNG terminal at Yabucoa:*** A new LNG terminal at Yabucoa is part of the least cost solution for a number of cases: high demand, inability to develop a land-based LNG at San Juan, and the ESM case. Under various cases, a large CCGT (300 MW) is developed at Yabucoa in conjunction with the LNG terminal, and in others a medium CCGT (150 MW) is developed. This terminal is recommended as a hedge against the potential that either of the other two LNG terminals (San Juan and Mayagüez) is not developed. In addition, as was observed in the ESM plan, if the LNG terminal and the 150 MW CCGT is developed at Yabucoa, the cost differential with the S4S2 that develops a CCGT at Mayagüez is minimal. This Yabucoa CCGT, when part of the plan, is selected in general by 2025 (i.e. as soon as possible).

As a consequence of the investment decisions above and the expected reduction in the load, accelerated by the assumed energy efficiency gains and the increased penetration of demand side resources, most of the existing generating fleet is recommended to be retired by 2025, with the exception of the CCGTs at San Juan and Aguirre and the GTs at Cambalache and Mayagüez. It must be stressed that these retirements can only be carried out when all the conditions the lead to the recommendation are in place.

### *B. Transmission and Distribution Decisions, Conclusions and Recommendations*

Central to the IRP is the capability to segregate the system into eight MiniGrids. The MiniGrids require the recommended generation and storage projects described above and the recommended transmission and distribution hardening projects described in Appendix 1. The recommended MiniGrids are designed to operate in grid-isolated mode following a major storm, ensuring continued supply to critical loads (those necessary to manage the recovery), and provide timely resupply to the priority loads (those required to regain normalcy and restart the economy) and balance the loads within the MiniGrid. Complementary to the MiniGrids, smaller microgrids have been identified for those areas that, due to geography and system topology are likely to remain isolated.

Under interconnected operation, no additional transmission investments beyond those already identified for grid hardening, were found necessary. This result was expected due to the shift towards the distribution of generation across Puerto Rico and the de-emphasis of the generation in the South.

The system was also found to be stable and have appropriate frequency response even with high levels of renewable generation online, thanks to the support provided by battery energy storage. However, studies also identified the need to reconvert some of the generators that were slated to be retired to synchronous condensers. Currently, Palo Seco Units 3&4 and San Juan Units 7 to 10 were found to be sufficient for this purpose and a detailed study is recommended.

### *C. Demand Side Decisions*

The demand side decisions are twofold:

1- Establish an Energy Efficiency (EE) program with the objective of reducing the demand in values approximating the 2% per year, as defined in Part 3 – Load Forecast.

2- Reinforce the distribution system and enable two-way flow of energy and providing voltage regulation and flicker control to facilitate the high penetration of distributed energy, as forecasted in this IRP (see Appendix 4 – Demand-Side Resources).

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## Exhibit 1-1: Summary of Investment Decisions by Scenario, Strategy and Load Growth[1]

| Count | Case ID | Scenario | Strategy | Sensitivity | Load | F - Class Palo Seco 2025 | F - Class Costa Sur 2025 | F-Class Mayaguez 2028 | F-Class Yabucoa 2025 | Small CCGT (LPG/NG) North | F - Class San Juan 2029 | Medium CCGT Yabucoa 2024 | Peakers (small CC) 2019-2022 | New Solar 2019 - 2022 | BESS 2019 - 2022 | New Solar 2023 - 2028 | BESS 2023 - 2028 | New Solar Total | BESS Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | S1S2B | 1 | 2 | | Base | **X** | ✔ (2025, 2028) | X | X | X | X | X | 396 | **1200** | 1200 | 2520 | 380 | 3720 | 2140 |
| 2 | S1S2H | 1 | 2 | | High | **X** | ✔ (2x2025, 2033) | X | X | X | X | ✔ Bayamon 2027 | 472 | **1200** | 1240 | 3060 | 120 | 4320 | 1880 |
| 3 | S1S2L | 1 | 2 | | Low | **X** | ✔ (2025, 2028) | X | X | X | X | X | 303 | **1200** | 1160 | 2100 | 180 | 3300 | 1800 |
| 4 | S1S3B | 1 | 3 | | Base | ✔ | ✔ (2025, 2028) | X | X | X | X | X | 343 | **1200** | 1120 | 2520 | 160 | 3720 | 1640 |
| 5 | S1S3H | 1 | 3 | | High | ✔ (141 MW | ✔ (2025, 2028) | X | X | X | X | ✔ Bayamon 2027 | 476 | **1200** | 940 | 3060 | 120 | 4260 | 2500 |
| 6 | S1S3L | 1 | 3 | | Low | **X** | ✔ (2025, 2028) | X | X | X | X | X | 303 | **1200** | 1120 | 2040 | 20 | 3240 | 1900 |
| 7 | S1S2S1B | 1 | 2 | 1 | Base | ✔ (141 MW | ✔ (2025, 2028) | X | X | X | X | X | 345 | **1200** | 1120 | 2640 | 500 | 3840 | 2700 |
| 8 | S1S2S2B | 1 | 2 | 2 | Base | **X** | ✔ (2x2025, 2028) | X | X | X | X | X | 444 | **1200** | 1140 | 2820 | 80 | 4020 | 1800 |
| 9 | S1S2S3B | 1 | 2 | 3 | Base | ✔ (141 MW | ✔ (2x2025, 2036) | X | X | X | X | X | 472 | **1200** | 1240 | 3060 | 120 | 4320 | 1880 |
| 10 | S1S1B | 1 | 1 | | Base | **X** | ✔ (2025, 2028) | X | X | X | X | X | 297 | **1200** | 1160 | 2520 | 0 | 3720 | 2220 |
| 11 | S3S2B | 3 | 2 | | Base | ✔ | ✔ | X | X | X | X | ✔ | 303 | **1500** | 980 | 2520 | 200 | 4020 | 2380 |
| 12 | S3S2H | 3 | 2 | | High | ✔ | ✔ | X | X | X | X | X | 303 | **1500** | 1180 | 4560 | 200 | 4560 | 3260 |
| 13 | S3S2L | 3 | 2 | | Low | ✔ 2027 | ✔ | X | X | X | X | X | 303 | **1500** | 940 | 1980 | 240 | 3480 | 1980 |
| 14 | S3S3B | 3 | 3 | | Base | ✔ | ✔ | X | X | X | X | X | 303 | **1500** | 1020 | 2460 | 260 | 2760 | 3960 |
| 15 | S3S3H | 3 | 3 | | High | ✔ 2027 | ✔ | X | X | ✔ (76MW) | X | ✔ | 303 | **1500** | 1100 | 2880 | 100 | 4560 | 2220 |
| 16 | S3S3L | 3 | 3 | | Low | ✔ 2027 | ✔ | X | X | X | X | X | 303 | **1500** | 960 | 1860 | 260 | 3420 | 2440 |
| 17 | S4S2B | 4 | 2 | | Base | ✔ | ✔ | ✔ | X | X | X | X | 388 | **1200** | 900 | 1020 | 40 | 2220 | 1080 |
| 18 | S4S2H | 4 | 2 | | High | ✔ | ✔ | ✔ | X | X | ✔ | ✔ | 479 | **1200** | 800 | 1380 | 0 | 2580 | 960 |
| 19 | S4S2L | 4 | 2 | | Low | ✔ | ✔ | X | X | X | X | X | 280 | **1200** | 1100 | 900 | 60 | 2100 | 1160 |
| 20 | S4S3B | 4 | 3 | | Base | ✔ | ✔ | ✔ | X | X | X | X | 388 | **1200** | 900 | 1140 | 160 | 2340 | 1540 |
| 21 | S4S3H | 4 | 3 | | High | ✔ | ✔ | ✔ | ✔ | X | X | X | 440 | **1200** | 1000 | 1380 | 0 | 2580 | 1420 |
| 22 | S4S3L | 4 | 3 | | Low | ✔ | ✔ | X | ✔ (2028) | X | X | X | 280 | **1200** | 1080 | 720 | 0 | 1920 | 1080 |
| 23 | S4S2S3B | 4 | 2 | 3 | Base | ✔ | ✔ | X | X | X | X | X | 303 | **1200** | 920 | 960 | 20 | 2160 | 1020 |
| 24 | S4S2S4B | 4 | 2 | 4 | Base | ✔ | ✔ 2027 | X | ✔ | X | X | X | 327 | **1200** | 1160 | 1140 | 0 | 2340 | 1220 |
| 25 | S4S2S5B | 4 | 2 | 5 | Base | ✔ | ✔ | X | X | X | X | ✔ | 591 | **1200** | 580 | 1140 | 80 | 2340 | 960 |
| 26 | S4S2S6B | 4 | 2 | 6 | Base | ✔ | ✔ | ✔ (2025) | X | X | ✔ (2028) | ✔ | 204 | **720** | 620 | 0 | 0 | 780 | 620 |
| 27 | S4S1B | 4 | 1 | | Base | ✔ | ✔ | ✔ | X | X | X | X | 324 | **1200** | 900 | 1140 | 0 | 2340 | 1460 |
| 28 | S5S1B | 5 | 1 | | Base | ✔ | **302 + 369** | X | X | X | X | X | 71 | **1200** | 1020 | 960 | 0 | 2160 | 1020 |
| 29 | S5S1S5B | 5 | 1 | 5 | Base | ✔ | ✔ | X | X | X | X | X | 60 | **1200** | 1060 | 1140 | 643 | 2340 | 1400 |
| **30** | ESM Plan | 4 | 2 | | Base | ✔ | **Eco Instead** | X | ✔ | ✔ | X | X | 418 | **720** | 440 | 180 | 140 | 900 | 800 |
| **31** | ESM high | 4 | 2 | | High | ✔ | **Eco Instead** | X | ✔ | ✔ | X | X | | **720** | | | | | |
| **32** | ESM low | 4 | 2 | | Low | ✔ | **Eco Instead** | X | ✔ | ✔ | X | X | | **720** | | | | | |

[1] See Part 5 – Resource Needs Assessment for a detailed description of the various scenarios.

Part
2

# Planning Environment

In this part Siemens documents the set of external factors that affect the environment under which PREPA is operating at the time of the IRP development. In addition to market conditions and stakeholders' input, it is important to consider the other key external factors that are in place, including applicable laws and regulations and conditions that have changed since the last IRP.

The description of this planning environment is a requirement of the IRP Regulation, which specifically requires the following:

- PREPA shall describe, at a minimum, the following factors: federal, state, or municipal standards and rules that impact the requirement for, or availability of, energy efficiency, renewable energy, fuel alternatives, or other resource requirements; and environmental standards and regulations that impact existing utility resources or resource choices at the present time and throughout the planning period.

- The Planning Environment part shall also include a discussion of substantial regulatory or legislative standards and rules that have changed since the approval of the most recent IRP.

Although there are numerous factors that have the potential to directly or indirectly impact the IRP, summarized herein are what have been identified to be the key factors warranting acknowledgement and documentation.

## 2.1 Environmental and Energy Standards and Regulations Applicable to PREPA

Puerto Rico is subject to most federal environmental standards applicable to energy generating facilities as well as state standards and regulations. A description of policies deemed as substantial to resource planning and how they are considered in the IRP analysis is included in Exhibit 2-1. These largely include the Environmental Protection Agency (EPA) federal air emission and water standards and Puerto Rico regulations governing energy efficiency, resource requirements, and environmental standards.

**Exhibit 2-1. Environmental and Energy Standards Applicable to PREPA**

| Category | Law / Regulation | Summary |
|---|---|---|
| Federal Environmental Standards - EPA[2] | Mercury and Air Toxics Standard (MATS) | The MATS rule was finalized in December 2011 and requires facility specific emission reductions of mercury, acid gases, and particulate matter. This is a command-and-control type of regulation with no allowance trading. Several PREPA facilities remain out of compliance and are required to run for reliability purposes. The IRP will inform pathways to MATS compliance for these units. |
| | National Ambient Air Quality Standards (NAAQS) | EPA updated attainment designations for $SO_2$ based on detailed air quality monitoring in December 2017. The standard for $SO_2$ is 75 parts per billion. Puerto Rico must finalize a state implementation plan (SIP) by May 2019 addressing compliance for two areas designated as nonattainment. Emissions from all generating units will be modeled and reported in the IRP analysis. The IRP will inform the SIP as PREPA units currently represent the most significant emission sources in the areas in Puerto Rico designated as nonattainment. |
| | Greenhouse Gas Emission Standards | The New Source Performance Standards (NSPS) for Electric Utility Generating Units was finalized in August of 2015 and sets a rate limit of 1,000lbs of $CO_2$/MWh for combined cycle natural gas plants and a limit of 1,400lbs of $CO_2$/MWh for coal plants. Units emitting above these levels are not included as new generation options due to this rule and market conditions not supporting, for example, new build coal. |
| | Clean Power Plan (CPP) | The final CPP under Section 111(d) of the Clean Air Act was finalized in August 2015 and required state-level emission targets by 2030. Puerto Rico was not covered under the final rule. Due to legal challenges and additional review of this rule, it is anticipated that this rule will be withdrawn in its entirety. The IRP therefore is not modeling compliance with the CPP. $CO_2$ emissions are reported and are expected to show a significant decline. |
| Puerto Rico Energy Standards | Renewable Portfolio Standard (RPS) | Act 82 of July 19, 2010, as amended, defines specific requirements to promote energy diversification by creating an RPS (Renewable Portfolio Standard). This rule requires load serving entities to supply increasing shares of retail sales with qualified renewable and alternative sources starting at 12 percent in 2015 increasing to 15 percent in 2027 and 20 percent in 2035. PREPA has not met RPS targets to date. The IRP will target compliance beginning in 2020, depending on feasibility, and maintain compliance for the balance of the study horizon. Sensitivities considering higher RPS targets are also modeled. |
| | Energy RELIEF Plan – Energy Efficiency | Act 57-2014 orders PREPA to adopt Puerto Rico's RELIEF Plan, which requires that within 3 years from July 1, 2014, at least 60 percent of the electricity generated in Puerto Rico from fossil fuels is generated in a highly efficient manner, as defined by the regulations approved by the PREB.<br><br>Government energy savings mandates also established under this Act include a 40 percent reduction in energy consumption by state agencies, public corporations, and judicial branch buildings by promoting energy savings performance contracts (ESPCs) unless proven not cost effective. The Legislature must reduce its electrical |

[2] These regulations and requirements are further detailed in the environmental section of the IRP found at the end of Part 4 – Existing Resources.

| Category | Law / Regulation | Summary |
| --- | --- | --- |
| | | energy consumption 12% by 2022, from a baseline of fiscal year 2012-2013. Municipalities must reduce electricity consumption by 5% annually for three years, or 15% in the first three years. Compliance was initially expected to begin in 2016 or 2017.<br><br>The State Office of Energy Policy will oversee the development and implementation of plans and programs to fulfill this law and publish semi-annual results from program evaluations. Act 57-2014 also mandates the benchmarking of energy use and monitoring of energy efficiency measures in all public buildings, including municipalities. |
| | Regulation on Microgrid Development | The final Microgrid Regulation of May 2018 sets the legal and regulatory framework required to promote and encourage the development of microgrid systems in Puerto Rico, enable customer choice and control over their electric service, increase system resiliency, foster energy efficiency and environmentally sustainable initiatives, and spur economic growth by creating a new and emerging market for microgrid services. It intends to promote the development of Microgrid systems by enabling their implementation through different business and operational models. The Final Microgrid Regulation recognizes three main types of microgrid systems: (i) Personal Microgrids; (ii) Cooperative Micrograds and (iii) Third-Party Microgrids.<br><br>While supporting microgrids where operationally and economically beneficial, PREPA expressed concerns with the final Microgrid regulation adopted by PREB and may seek changes. Among other things, final Microgrid regulation authorizes multi-customer "in front of the meter" microgrids that raise a number of legal, financial, operational, safety, and customers rights issues and that are not compatible with the certified Fiscal Plan objectives; the regulation gives customers degrees of "optionality" in terms of switching back and forth from taking and not taking PREPA service that no utility could accept and that also is out of synch with the Fiscal Plan; and the regulation is problematic or incomplete in certain other respects.<br><br>In the context of long term resource planning, the IRP will identify microgrids that could be owned by the utility or private entities. Moreover, if during the development of the IRP plans for a privately owned microgrid become available, this could be incorporated as an option when assessing the coverage of the MiniGrids. |

**Source: various statutes referenced, Siemens**

Additional detail on how these laws and regulations are accounted for in the IRP is included throughout the IRP report.

## 2.2 Laws and Regulations Changed Since Last IRP

### Regulation on Integrated Resource Planning for the Puerto Rico Electric Power Authority (Regulation 9021)

The PREB adopted the Regulation 9021 on April 24, 2018. This regulation, referred to as the Regulation on Integrated Resource Plan for Puerto Rico Electric Power Authority, was enacted as required under the Act No. 83 of May 2, 1941, as amended, known as the Puerto Rico Electric Power Authority Act (Act 83 of 1941), and Act 57-2014, as amended, the Puerto Rico Energy Transformation and RELIEF Act. Regulation 9021 serves to make sure that the IRP is a useful tool to improve the system's reliability, resiliency, efficiency, and transparency, and offer electric power services at reasonable prices. Specifically, this regulation defines the required contents and organization of the IRP, the process with PREB, and performance metrics for PREPA following PREB's review and evaluation of the IRP.

Key parameters of the IRP are reflected including the defined 20-year planning period, the contents and organization of the IRP report and technical appendices, and sourcing requirements and documentation. As noted above, the requirement for documentation on the IRP planning environment is one of the required parts of the IRP. This IRP analysis also reflects the specific requirements outlined in Regulation 9021 regarding load forecasting, existing resources, resource needs determination including planning reserve margin, new resource options including supply- and demand-side resources as well as distributed and storage resources.

To account for a range of future market conditions, Regulation 9021 specifies that the IRP shall consider multiple scenarios that cover a reasonable range of possible outcomes for uncertain forecasts and that the IRP shall consider sufficient scenarios to capture a wide range of possible risks and justify scenarios included and those excluded. It is also required that a single reference case representing PREPA's best understanding of expected future conditions is included in the IRP. This scenario is called the Base in this report.

The approach to analyze the resource options and tools used are also discussed in the requirements. Specifically, a capacity expansion model is required for the basis of the analysis. Further, sensitivity analysis of each resource plan is required. In this analysis, Siemens is using AURORAxmp® (by EPIS, now Energy Exemplar) as the long-term capacity expansion tool. Risk analysis is performed using scenarios (high/low/base) and a number of sensitivities as discussed later in this report.

Finally, Regulation 9021 lays out the requirements for analysis of the transmission and distribution system. This will be addressed in the IRP analysis using AURORA nodal modeling, PSS®E transmission system studies and targeted distribution hardening distribution studies[3].

### Regulation on Microgrid Development (Regulation 9028)

The PREB adopted the Regulation 9028 on May 18, 2018. This regulation, referred to as the Regulation on Microgrid Development, sets the legal and regulatory framework required to promote and encourage the development of microgrid systems in Puerto Rico, enable customer choice and control over their electric service, increase system resiliency, foster energy efficiency and environmentally sustainable initiatives, and spur economic growth by creating a new and emerging market for microgrid services. It intends to promote the development of Microgrid systems by enabling their implementation through different business and operational models. The Final Microgrid Regulation recognizes three main types of microgrid systems: (i) Personal Microgrids; (ii) Cooperative Microgrids and (iii) Third-Party Microgrids.

[3] These studies include those carried out by NYSSGC and ProsumerGrid for the Puerto Rico Grid Re-Design™ Study.

While supporting microgrids where operationally and economically beneficial, PREPA expressed concerns with Regulation 9028 adopted by PREB and may seek changes. Among other things, this regulation authorizes multi-customer "in front of the meter" microgrids that raise a number of legal, financial, operational, safety, and customers rights issues and that are not compatible with the certified Fiscal Plan objectives; the regulation gives customers degrees of "optionality" in terms of switching back and forth from taking and not taking PREPA service that no utility could accept and that also is out of synch with the Fiscal Plan; and the regulation is problematic or incomplete in certain other respects.

### PREPA Revitalization Act, Act 4 of 2016

On February 17, 2016, the Governor signed into law the Puerto Rico Electric Power Revitalization Act, Act 4 of 2016. The law aimed to begin restructuring for PREPA's $9 billion debt as a means to start addressing the Commonwealth's $70 billion debt. Under the law, the PREPA Revitalization Corporation was created. This entity would issue new bonds in exchange for PREPA bonds under a new securitization that did not close. On July 30, 2018, the Governor of Puerto Rico and the federal Financial Oversight and Management Board announced a new agreement relating to restructuring certain of PREPA's debt, which may or may not implicate Act 4 in one or more respects. A restructuring, if consummated, could affect PREPA's cost of capital in the IRP.

### Puerto Rico Oversight, Management, and Economic Stability Act (PROMESA)

On June 30, 2016, President Obama signed into law, the federal Puerto Rico Oversight, Management, and Economic Stability Act (PROMESA), which would create a structure for exercising federal oversight over the fiscal affairs of territories. PROMESA would establish an Oversight Board with broad powers of budgetary and financial control over Puerto Rico. PROMESA also would create procedures for adjusting debts accumulated by the Puerto Rico government and its instrumentalities and potentially for debts of other territories. Finally, PROMESA would expedite approvals of key energy projects and other "critical projects" in Puerto Rico. On July 2017, PREPA became a Debtor under the Title III process of PROMESA. The Fiscal Plan to be approved by the Financial Oversight and Management Board (FOMB) could affect PREPA's cost of capital in the IRP. On the other hand, the results of the IRP, especially the infrastructure investments, could affect PREPA's Fiscal Plan and its debt restructuring.

### *Ley para Transformar el Sistema Eléctrico de Puerto Rico* (Law to Transform the Electric System of Puerto Rico), Act 120-2018

On June 20, 2018, the Law to Transform the Electric System of Puerto Rico was approved for the purpose of authorizing the legal framework required for the sale, disposition or transfer of assets, operations, functions, and services of PREPA. In general, this act provides the legal framework for the privatization process of PREPA, by means of public private partnerships (PPPs) transactions, among others. Act 120-2018 also establishes the necessary safeguards to ensure a fair and transparent process and amends the Act 29-2009, as amended, known as the Public Private Partnerships Law. Transactions like generation assets sales and other assets PPPs could affect PREPA's cost of capital in the IRP.

### Puerto Rico Senate Bill 1121 for creating the Puerto Rico Energy Public Policy Act

On November 6, 2018, the Senate of Puerto Rico approved its Bill 1121 for creating the Puerto Rico Energy Public Policy Act. The main purpose of the act, if approved, is to complement Act 120-2018 for the privatization process of PREPA, creating the energy public policy of Puerto Rico. This bill is currently under the consideration of the House of Representatives. If approved, the act will amend Act 83 of 1941, Act 57-2014 and Act 82-2010, among others. The amendments to these laws could affect the assumptions and scenarios in the IRP, including the cost of capital simulated.

## 2.3 Solar and Energy Storage Cost Decline

Due to technology improvements, growing economies of scale, and technology maturation, costs for solar energy and battery storage have declined rapidly in recent years. This is a trend that many anticipate will continue in the coming years, particularly for larger, utility-scale solar installations that are generally seen as less mature relative to solar installations at or on residential and commercial facilities. The NREL[4] Annual Technology Baseline (ATB) 2018 anticipates utility solar capital costs will fall at a compound annual rate of 1.5%-3% from 2018-2050. Regarding battery energy storage, an even less mature technology, many expect rapid declines due to economies of scale as adoption increases for both storage and electric vehicle applications. In China, 332 GWh of battery manufacturing capacity have been announced by 2021.[5] Despite this general consensus at this time for future declines in cost, the magnitude and timing of these declines are less certain. Also, as these technologies become more affordable and, consequently, their demand increases, it is uncertain how the offer and their cost will behave in the future.

Solar and solar paired with energy storage, such as lithium-ion (Li-ion) batteries, represent clean and renewable energy options for Puerto Rico that do not require the need for fuel infrastructure or volatility associated with fuel costs. Further, with additional storm hardening tactics like deeper anchoring of ground mounted solar installations, these technologies can withstand significant hurricane conditions. Battery storage technologies can produce or absorb power, providing value to utilities in managing supply to meet load throughout the day. Due to the remote location and hardening requirements, cost premiums (higher costs) for these technologies are assumed in this analysis relative to that, for example, of new solar builds in advantageous areas in the continental U.S. However, the changes in cost outlook even relative to a few years ago are reflected in this IRP analysis as well as a range of outcomes as to the timing and magnitude of these technology cost declines. Overall, however, this trend and the need for a reliable and resilient electric grid present a unique opportunity for Puerto Rico to transition to cleaner, renewable energy sources that by their distributed nature support resiliency.

It is expected that the utilities will deploy huge amounts of solar energy and battery storage, due to the decline in their costs. However, there is no precedent in the electric industry of such deployments and, consequently, there is no experience in developing projects for the simultaneous integration of very large amounts of solar energy and battery storage, in addition to no operational experience managing them. Hence, even though the development of these technologies promise to achieve these benefits, it is important to deploy them in an

[4] National Renewable Energy Laboratory of the federal Department of Energy

[5] https://www.wsj.com/articles/batteries-are-taking-over-the-world-1511880319

orderly and planned manner, so the utility is able to acquire the needed operational experience of managing a new technology which has not yet been proved at the large scale that was analyzed in this IRP.

New wind generation is also considered as a part of the IRP analysis. Although the wind technology costs are not declining as noteworthy as solar and battery storage costs, the performance of wind turbines is improving particularly at low wind speeds. This increased performance offers a lower levelized cost of energy from new wind projects. Part 7 – Assumptions and Forecasts provides further details on Siemens forecast.

## 2.4 Hurricane Impacts on the IRP

Even before the 2017 hurricanes, Puerto Rico's economy was in structural decline, with GDP[6] and population falling by at least a percentage point a year. The devastation of Hurricanes María and Irma in 2017 exacerbated these trends with this event alone resulting in a 4 percent population decline due to migration and the death toll from the storm.[7] These conditions and the uncertainty as to the future population and economy of Puerto Rico are key considerations in this IRP.

Outlooks for economic growth vary between highly credible sources including the Financial Oversight and Management Board (FOMB), the World Bank, and the International Monetary Fund. Some suggest a relatively fast recovery from the impacts of the hurricanes due to disaster relief spending, structural reforms and improved fiscal transparency in the Government of Puerto Rico (Government). On the other hand, the Fiscal Plan has the potential to negate some of these economic growth drivers. Central to population and economic growth is a reliable and cost effective electric supply to Puerto Rico.

A more detailed discussion of these impacts, specific to the baseline load projections and range of load uncertainty considered in the IRP analysis, is included in Part 3 – Load Forecast of this report. A real additional risk of future natural disasters in the coming years cannot be ignored. Although these quantum events are difficult to directly include in such an analysis, the range of future market conditions, particularly load growth, aim to incorporate a realistic range of recovery outlooks for Puerto Rico and the resulting impacts to resource decisions over the 20-year planning period are covered in this IRP.

Puerto Rico's exposure to hurricanes and the disruption that they bring to overhead transmission and distribution facilities necessitates that the IRP identifies an optimal balance between local generation resources and limited centralized new generation. To achieve this, the IRP defines portfolios based on the three strategies detailed in Section 5.2. Central to these strategies is the concept of segregating the system into a number of electrical islands (called MiniGrids), defined considering the vulnerabilities of the overhead transmission system, whose lines could take a month or more to rebuild after a major hurricane, and contain the identification of facilities that need to be hardened (e.g., undergrounding) to

[6] Gross domestic product

[7] Per a study from the Harvard T.H. Chan School of Public Health, published in New England Journal of Medicine, May 2018

ensure integrity of supply to critical loads and timely recovery of the balance of the local loads. Appendix 1 provides more details.

The IRP analysis will consider a range of load outcomes as scenarios (High, Base and Low). Additional variables including the cost of fuel and capital costs for new supply options are also analyzed through sensitivities. Scenario and sensitivity analysis will consider alternate regulatory outcomes (i.e. strengthened future renewable mandate) and future fuel supply options (i.e. natural gas availability to fossil generating facilities located at the north of the island).

## 2.5 PROMESA Federal Act

The Puerto Rico Oversight, Management, ad Economic Stability Act (PROMESA), signed into law by President Obama on June 30, 2016, is a unique federal legislative enactment that includes a number of different provisions that apply to Puerto Rico in respect to its own financial situation. This Law became effective one day before Puerto Rico defaulted on significant payment obligations. Key provisions of PROMESA include:

**Financial Oversight and Management Board** – PROMESA required a Financial Oversight and Management Board (FOMB) to independently oversee fiscal planning, budgeting, and operations. This Oversight Board consists of seven members appointed by the President of the United States and an ex officio member without voting rights, the Governor or appointee. Among other public entities, PREPA is a listed entity covered by PROMESA and the Oversight Board. As such, activities of PREPA fall under the FOMB, specifically as it relates to its financial planning.

**Fiscal Plan** – PROMESA requires the development and maintenance of a fiscal plan for Puerto Rico. This plan, at a minimum is required to document the reduction of deficits, payment of debts, and fiscal accountability. Key also to this plan is a description of how critical services, including electric service, will be maintained. Additional contents of PREPA's own fiscal plan are detailed in Part 3 – Load Forecast.

**Stay** – Title IV of PROMESA implemented a temporary stay on actions and litigation to collect from Puerto Rico entities or enforce liabilities and claims. This stay, similar to protections under the U.S. Bankruptcy code, is enacted to allow Puerto Rico to assess finances and negotiate with creditors.

**Debt Reorganization** – Title III of PROMESA allows for Puerto Rico or designated representative selected by the FOMB on behalf of the Government to file for reorganizing its debt. This provision maintains elements of Chapter 9 under the U.S. Bankruptcy Code as well as unique provisions specific to Puerto Rico. This includes safe harbors for municipal debts. Title III filing must be approved by the Oversight Board.

### 2.5.1 Title III

During the Stay period that, with extensions, was in place through May 1, 2017, voluntary negotiations with creditors were ongoing. Following this time, the Oversight Board determined it necessary to file a petition under Title III of PROMESA. The preference is to continue to pursue voluntary negotiations, however the Title III filing was deemed necessary to protect the Government and its people.

As of May 3, 2017, Puerto Rico filed for bankruptcy under Title III of PROMESA. PREPA filed for bankruptcy on July 2017 and became a debtor under Title III of PROMESA. The Government and agencies are working to address the $70 billion debt. PREPA is working with the Government and its statutory fiscal agent, the Fiscal Agency and Financial Advisory Authority (AAFAF), to reach restructuring and the electric sector transformation.

### 2.5.2 Title V

Title V defines a Critical Project Process which promotes expedited permitting to advance major projects as those that could be identified in the IRP to develop local generation and/or hardened transmission or distribution facilities to provide resiliency.

Title V establishes the position of the “Revitalization Coordinator,” who operates under the FOMB and who is charged with evaluating infrastructure projects that will provide direct and substantive benefits to Puerto Rico. After receiving a project proposal, the Revitalization Coordinator identifies all Puerto Rico agencies that have a role in permitting, approving, or authorizing the proposed project, and those agencies are required to submit to the Revitalization Coordinator an expedited permitting process, with the goal of ensuring that critical projects are given priority to the maximum extent possible. In the case of energy projects, the process requires the approval of the PREB. The effectiveness of this procedure is still to be confirmed, but it defines a path that would benefit the implementation of the recommendations of this IRP.

## 2.6 Fiscal Plan

As noted above, PROMESA required the development of a fiscal plan and budget for Puerto Rico that will supersede previous fiscal plans. PREPA submitted its draft fiscal plan on February 21, 2017 and the latest plan was published, following updates after the post-hurricane restoration in April 2018. PREPA’s fiscal plan aligns with the Government’s fiscal plan and addresses areas specific to PREPA. The plan focuses on the need for privatization of assets, efficiency in expenditures, and the need for being an economic growth engine for Puerto Rico.

PREPA’s current situation including aging and poorly maintained infrastructure, limited fuel options, and operational challenges drive the current high cost of energy service. The ongoing recession has resulted in lower energy sales, required subsidized service to certain customers, while ineffective bill collection from government and other customers has further stressed PREPA’s financial situation. PREPA’s rates in recent history have been insufficient to cover costs. Growing debt limited ability to invest in the grid and the PREPA pension fund. These limitations in investments along with legislation cutting PREPA’s employees benefits have caused an increase in the service outages and essential employees resignations and early retirements. As a result, PREPA’s service reliability and infrastructure lags industry standards. The fiscal plan details a path to modernization. Key to this transformation is the development of PREPA’s 2018 IRP. Details and timeline for the IRP are included in the plan.

The fiscal plan presents a path forward covering the term through FY2023[8] based on what is known at this time. Key provisions detailed in the fiscal plan include:

- Behind the meter, distributed generation
- System efficiency, reducing system losses
- Reduce PREPA operating costs (i.e. labor costs and maintenance expenses which were provided by PREPA and reflected in the analysis)
- Updated load outlook to account for post hurricane conditions
- Rates anticipated and rate structure including the ongoing cost of debt service obligation
- Privatization of generating assets

In the fiscal plan, PREPA reports improvements in its liquidity and expectation that it will return to cash flow neutrality in FY2019. Scenarios for post-transformation capital spending and costs are presented. These will be refined and further updated with results of the IRP.

The IRP will be performed within the context of the relevant aspects of the FOMB certified Fiscal Plan for PREPA and the PREPA Governing Board's vision which is presented below.

## 2.7 PREPA Board Vision Statement

Noting the need for an efficient and resilient system, on February 1, 2018, the PREPA Governing Board released its vision statement to guide the future of the utility. This vision addressed the reliability and resilience of the system, the transition to a sustainable system – both financially and environmentally sustainable – and its importance in acting as an economic growth engine for Puerto Rico. These elements are noted and factored into the structuring of the IRP analysis, scenarios and sensitivities, and inputs. The vision statement as approved is presented in Exhibit 2-2 below.

**Exhibit 2-2. PREPA Vision for the Future of Power in Puerto Rico**

| Pillar | Summary |
| --- | --- |
| System is Customer-Centric | The system serves the customer with affordable, reliable power, with transparent metrics for quality of service and with equitable consideration across all customers. Quality/Reliability can be differentiated for customers in a manner that serves their total cost and risk objectives. Customers are engaged by innovative products and |

[8] FY means Fiscal Year and, hence, FY2023 is the fiscal year starting July 1, 2022 and ending June 30, 2023

| Pillar | Summary |
|---|---|
| | value-added services that provide choice among rate plan and risk management options and provide access to wholesale contracting options for large customers. Customers are empowered with behind-the-meter alternatives for energy efficiency, demand management, and distributed generation, with the ability to become prosumers if they so choose. |
| System Promotes Financial Viability | The system is premised on positive economics on both sides of the meter. Rates are reasonable and create value for the customer, while pricing is sufficient to cover costs. Rate and market design create incentives to purchase, consume or produce energy in a manner that benefits the entire system. Subsidies are minimized, and those that remain have a non-distortionary impact. Operational excellence and sound long term planning reduce the cost to serve. Rates are affordable within a model that allows the utility to earn a reasonable rate of return and service its debt. The business model is robust to changes such as outmigration and reduction in energy demand and does not create disincentives for adoption of cheaper energy resources, either at the grid level or at the customer premises. |
| System is Reliable and Resilient | The grid is thoughtfully planned, well maintained and safely operated to achieve defined reliability and resiliency goals. There is visibility into the system at all levels, and control where appropriate. Standards for recoverability create a measure for resilience. The choice of architecture (distributed vs. regionalized vs. centralized) is intentionally made to balance reliability/resilience and cost objectives while also taking advantage of advancements in technology and innovation. |
| System is a Model of Sustainability | There is a progressive focus on diversifying energy resources and reducing the carbon intensity of the power sector, in both primary generation and backup generation. Power generation is efficient and minimizes emissions. Customers have incentives to use energy wisely and to generate their own clean energy. The grid and grid systems are designed to take maximum advantage of increasingly cost effective renewable power generation alternatives and to integrate emerging technologies. |
| System serves as an Economic Growth Engine for Puerto Rico | The quality, reliability, and cost of power attracts new commercial and industrial development to Puerto Rico and encourages existing commercial and industrial customers to expand their operations. Transformation and reinvestment in the power system creates new jobs. Innovation in the generation and delivery of power creates a local ecosystem of businesses that provide for evolving needs for equipment, technology and services in Puerto Rico and beyond. |

Source: PREPA, 2018

## 2.8 Privatization

The Governor of Puerto Rico has publicly stated that the reconstruction and transformation of the electricity sector will include the privatization of PREPA's generating facilities. This would include the generating assets and be complemented by the operation of the transmission and distribution system by a third party. The Law to Transform the Electric System of Puerto Rico was passed on June 12, 2018, becoming Act 120-2018. As a means to transform Puerto Rico's electric system into a modern and sustainable one, system ownership including generating assets will be open to private entities. PREPA and Puerto Rico's Authority for Public-Private Partnerships are to collaborate in the process to privatize assets. Final agreements would need to be ratified by Puerto Rico's Legislature and the Governor.

Request for Proposals are to be issued for PREPA's owned generating units. Bids will be evaluated on metrics that balance commercial interests and social responsibility as well as the bidder's interest and ability to transition to cleaner generating sources when reasonably possible. The act also requires the PREB to sign off on the sales and regulate tariffs and other charges for electricity following the transactions. Under the act, the PREB has fifteen days to review and decide on the approval. Approved contracts would be issued an "energy compliance certificate". Finally, the act expands the PREB's staff to facilitate timely decisions.

Based on the Act 120-2018 authorizing PREPA to sell its generating assets to more than one private buyers, Siemens considered future builds to be financed by third parties, assuming PREPA obtains financial backing to contract as a credit-worthy counterparty if needed.

Part
3

# Load Forecast

This section covers Siemens load forecast methodology and results. The energy efficiency and demand response complementary to this analysis are presented in Appendix 4.

## 3.1 Data, Assumptions and Methodology

### 3.1.1 Historical Energy Sales

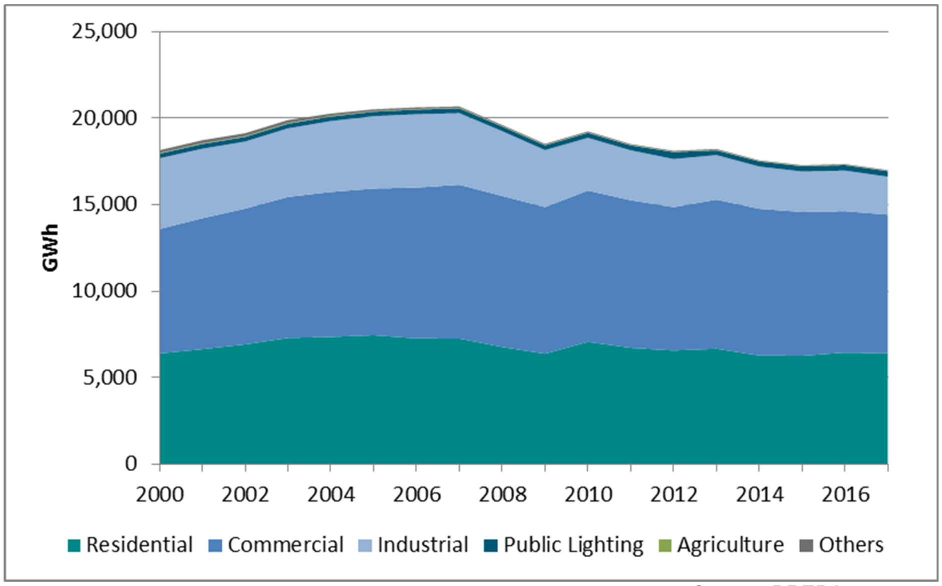
PREPA provided monthly historical energy sales for July 1999 – June 2018 (Fiscal Years 2000 – 2008) divided into six customer classes: residential, commercial, industrial, agriculture, public lighting, and other. The commercial sector accounted for 47% of the total sales in FY 2017, followed by residential at 38% and industrial at 13%. Overall, sales to residential, commercial, and industrial customers represented 98% of total sales in FY 2017, the remaining 2% originated from the public lightning sector. These FY 2017 results are generally consistent with the results of recent historical years for sales by customer class.

Electricity sales in Puerto Rico declined by 18% since the 2008 recession and net migration. Starting in 2007 until 2017, Puerto Rico's real gross national product (GDP) shrank by approximately 17% and the population declined by over 15%[9]. For FY 2018, total energy sales declined 22%, reflecting the disruption in the transmission and distribution networks due to the hurricanes as well as customer billing delays[10].

Industrial sales declined by 47% in FY 2007 to FY2017, while residential and commercial sales fell 12% and 10% respectively. Industrial share of the total energy sales declined from 20% in FY 2007 to 13% in FY 2017. In contrast, the share of commercial sales increased by 4 percentage points. Exhibit 3-1 shows historical energy sales for FY 2000 to FY2017 by customer class.

[9] Based on data provided by the Financial Oversight & Management Board (FOMB)
[10] Based on preliminary data provided by PREPA

**Exhibit 3-1. Historical PREPA Annual Sales by Customer Class (GWh)**




Source: PREPA

PREPA and Financial Oversight & Management Board (FOMB) provided historical data such as population, gross national product (GNP), and weather. These data along with long-term projections of GDP and population were leveraged to create a model and develop gross load forecasts by customer class.

### 3.1.2 Load Forecast Methodology

The load forecasting methodology employed customer-class specific, statistical and econometric time-series models to develop forecasted monthly energy sales for the three largest customer classes: residential, commercial and industrial. The gross energy consumption forecast was developed using a Classical Linear Regression Model (CLRM) in which the dependent variable, energy sales, is expressed as a linear equation combining the independent variables. For Puerto Rico, 15 variables were used including:

- a weather variable (cooling degree days or CDD)
- two economic variables (population and GNP)
- 12 month specific dummy variables (one for each month of the year) to capture the seasonality of energy demand on a monthly basis

Population was found not to have a statistical significance for industrial. Therefore, manufacturing employment was substituted for population as an independent variable in the regression analysis used to forecast industrial energy consumption.

The econometric model uses an ordinary least-squares regression technique and is developed in MATLAB[11]. This basic approach is widely used to develop long-term load forecasts for independent system operators like PJM, the California Energy Commission and individual utilities. Siemens used monthly historical data for FY 2000 through FY 2017 to estimate the regression coefficients applied to the forecast, with 210 observations for each variable.

The unique coefficients that are produced for each independent variable are used to develop the gross energy sale forecast. The 12 monthly dummy binary variables were included in the forecast formulation to capture monthly seasonality in demand. The sum product of the coefficients and variables on a monthly basis result in the gross energy forecast equation is shown below:

$$Demand = C_1 * V_1 + C_2 * V_2 \dots \dots \dots C_{17} * V_{17} + b$$

In the equation above, $C_x$ is the coefficient corresponding to each independent variable $V_x$, and *b* represents a constant.

The statistical significance and predicted fit of the model for residential, commercial, and industrial classes was robust, with all three customer classes combined representing approximately 98% of the total load, in line with historical values. Exhibit 3-2 illustrates the variables used to develop the forecast for each of three largest classes.

**Exhibit 3-2. Independent variables for Each Customer Classes**

| Residential | Commercial | Industrial |
|---|---|---|
| ▪ CDD<br>▪ GNP<br>▪ Population<br>▪ 12 months variable | ▪ CDD<br>▪ GNP<br>▪ 12 months variable | ▪ CDD<br>▪ GNP<br>▪ Manufacturing employment<br>▪ 12 months variable |

For the smaller customer classes (agriculture, lighting, and other) the overall fit of the CLRM model was weak with the economic and weather fundamental variables providing little explanatory value on the energy consumption for each class. For these customer classes, Siemens developed the forecast of energy consumption for these three classes based on historical seasonality and using a simple extrapolation technique with the expectation that each class will follow similar growth rate as the overall system. This simpler forecast method was deemed acceptable since the three classes collectively represented approximately 2% of the total energy consumption.

[11] MATLAB is a numerical computing environment and proprietary programming language developed by MathWorks

### 3.1.3 Fundamental Drivers for the Load Forecast

In line with the econometric model, Siemens used population, GNP, CDD and the monthly dummy variables as explanatory variables to develop the load forecast by customer class for FY 2019–2038. Other economic data considered included disposable income, income per-capita, and the heat index for weather. However, these additional independent variables were ultimately not incorporated in the final forecast due to their high correlation to other variables already incorporated in the analysis such as CDD (highly correlated to the heat index) or the GNP (highly correlated to disposable income), which diluted their predictive value.

For weather data, Siemens found CDD as the most significant statistically variable to predict the impact of weather on load, which is consistent with Puerto Rico having a tropical climatic zone with year-round warm temperatures averaging 80°F (27°C) in low elevation areas, and 70°F (21°C) in the central mountains of the island. Although temperature variation is relatively modest throughout the year, the overall heat level drives cooling load trends (demand for air conditioning). Weather data was sourced from the National Oceanic and Atmospheric Association (NOAA) for the San Juan station, as a representative for the overall island temperature and rainfall trends. Higher elevation locations were not found to have a significant impact on overall load changes.

Customer rates were considered in the analysis, in particular industrial rates, but they were found not to have a strong historic correlation to demand and explanatory power. From 2000 to 2017, there were periods where industrial demand fell along with declining industrial rates or the opposite. The expectation would be an inverse relationship with lower demand as a consequence of rising industrial rates. The manufacturing sector in Puerto Rico, mostly comprised of pharmaceutical, textiles, petrochemicals, and electronics; appears to be less responsive to changes in customer rates compared to other manufacturing industries such as steel or aluminum, which are highly sensitive (high elasticity). The residential sector is traditionally a sector with low response to changes in retail rates and to some extend the commercial customers. However, sustained high retail rates could change customer behavior and create more incentives for implementation of energy efficiency programs.

Siemens compiled and reviewed macroeconomic data (historical and forecasts) from several sources including Moody's Analytics, the International Monetary Fund, World Bank, the U.S. Census Bureau, Federal Reserve of Economic Data of St. Louis (FRED) and Puerto Rico's Federal Management Oversight Board (FOMB), among others.

Exhibit 3-3 below shows the historical annual values for the independent variables used in the regression analysis.

**Exhibit 3-3. Historical Population, Macroeconomic, and Weather Variables**

| Year | Population (thousands) | GNP (Real Million US dollars) | Cooling Degree Days (Monthly Average) | Manufacturing Employment (thousands) |
|---|---|---|---|---|
| 2000 | 3,815 | 6,773 | 453 | 143 |
| 2001 | 3,822 | 6,873 | 476 | 132 |
| 2002 | 3,825 | 6,850 | 477 | 121 |
| 2003 | 3,827 | 6,991 | 472 | 118 |
| 2004 | 3,825 | 7,178 | 461 | 118 |
| 2005 | 3,814 | 7,315 | 478 | 115 |
| 2006 | 3,794 | 7,351 | 473 | 110 |
| 2007 | 3,772 | 7,262 | 489 | 106 |
| 2008 | 3,750 | 7,054 | 467 | 101 |
| 2009 | 3,733 | 6,784 | 499 | 92 |
| 2010 | 3,702 | 6,542 | 491 | 87 |
| 2011 | 3,656 | 6,432 | 462 | 84 |
| 2012 | 3,615 | 6,466 | 506 | 82 |
| 2013 | 3,566 | 6,458 | 496 | 76 |
| 2014 | 3,504 | 6,348 | 519 | 75 |
| 2015 | 3,441 | 6,312 | 513 | 74 |
| 2016 | 3,372 | 6,209 | 506 | 74 |
| 2017 | 3,190 | 6,060 | 504 | 72 |

Source: FOMB (GNP), Moody's Analytics (Population), NOAA (weather), Federal Reserve Bank of St. Louis Economic Data - FRED (Manufacturing Employment)

Before the hurricane, Puerto Rico's economy was in structural decline, with GNP and population falling by at least a percentage point a year since 2006, the last year when the GNP saw an increase. Puerto Rico's GNP shrunk 8% in the decade after the Great Recession with GNP reaching $6 billion dollars in 2017 (real dollars).

Population declined 15% since 2007 with Maria and Irma accounting for 4 percentage points of this decline in population (182 thousand people in 2017) due to the combined impact of migration and the death toll after the storm, estimated at over 4,100 people[12].

### 3.1.4 Macroeconomic and Weather Projections

Historical monthly NOAA data was utilized (2000-2016) to develop expected monthly CDD under normal weather conditions. The expected normal weather conditions and its associated monthly CDD was used as a common basis for each year of the energy sales forecast. Exhibit 3-4 shows the normalized CDD used for the forecast.

[12] Per a study from the Harvard T.H. Chan School of Public Health, published in New England Journal of Medicine, May 2018

**Exhibit 3-4. Weather Variables**

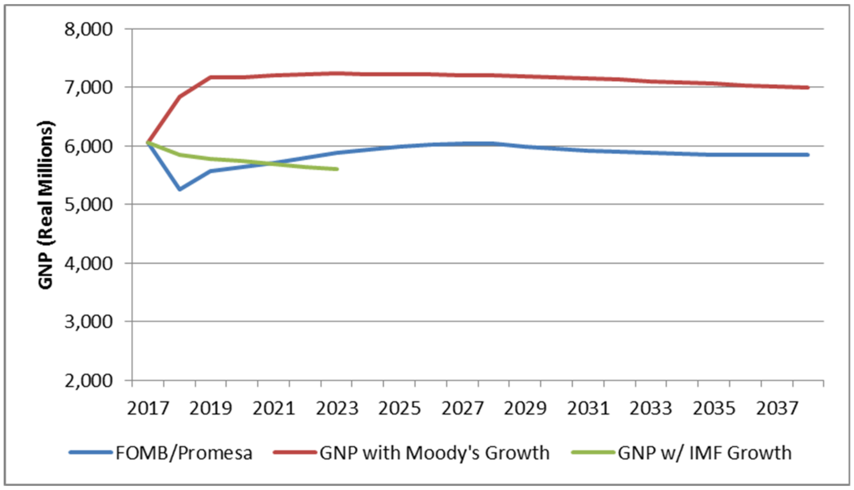
| Month | Cooling Degree Days (CDD) |
|---|---|
| January | 391 |
| February | 361 |
| March | 427 |
| April | 454 |
| May | 511 |
| June | 547 |
| July | 567 |
| August | 572 |
| September | 552 |
| October | 552 |
| November | 466 |
| December | 427 |

Source: NOAA, Siemens

To be consistent with the FOMB, Siemens used their historical and forecasted data for GNP and population in 2019–2038. According to FOMB, the GNP is estimated to decline 13% for FY 2018, reflecting the impact of hurricanes Maria and Irma on the economy. However, GNP is projected to grow at 6.1% in FY 2019. FOMB forecast shows a relatively fast recovery from Maria's impact, driven by the effect of the Disaster Relief Fund spending program. In the medium-term GNP is projected to increase at 1.6% per-year in 2019-2027. After 2027, GNP growth is projected to soften to -0.3% per-year. The structural reforms are projected to enhanced economic growth, including a reform of the electrical grid, enhanced fiscal transparency and a labor reform aimed to bring Puerto Rican labor law into closer alignment with U.S. law. An offset to economic growth is expected to come from the proposed fiscal consolidation plan which could bring significant austerity over the next few years to reduce Puerto Rico's public debt.

Siemens considered other outlooks as well, including Moody's Analytics (Moody's) and the International Monetary Fund (IMF), as shown on Exhibit 3-5. Moody's projects the GDP to recoup much of its hurricane-related losses and to remain relatively stable throughout the forecast horizon. The IMF shows a more pessimistic forecast through 2023 with GDP not recovering from the aftermath of hurricane Maria through 2023.

**Exhibit 3-5. Puerto Rico GNP Forecasts**

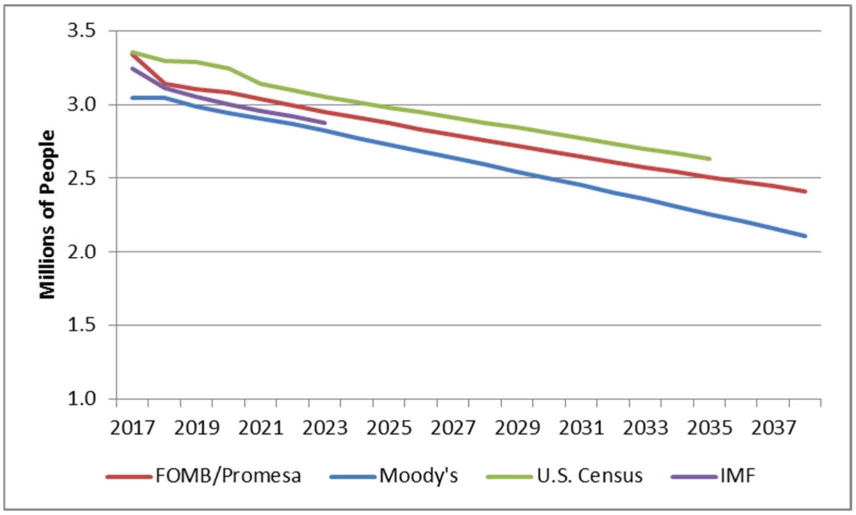



Note: The forecast have been standardized for comparison purposes using the implied growth rates. Moody's GNP forecast is based on real 2009$ and the IMF based on real 1954$.

Sources: Moody's June 2018 Forecast, IMF April 2018 WEO, Financial Oversight and Managing Board of Puerto Rico, Fiscal Plan April 2018

The FOMB forecast for population shows a decline of 5.8% in FY2018 due to hurricane fatalities and net migration off the island. Over the study period, FOMB projects population to decline at 1.3% per year in 2019–2038. Population in Puerto Rico is projected to fall by over 900 thousand people by 2038. Moody's projects a faster pace of population loss over the next decade, compared to FOMB, as the island gets increasingly dragged into a negative feedback loop whereby out-migration undermines the tax base and the provision of public services (which deteriorated since Hurricane Maria), will engender more out-migration. The U.S. Census (prior to Maria) projects higher population levels but still with a falling trend through the forecast. The IMF provides a forecast between the projections from FOMB and Moody's.

**Exhibit 3-6. Puerto Rico Population Forecast**




Sources: Moody's June 2018 Forecast, IMF April 2018 WEO, US Census Bureau August 2017

Exhibit 3-7 shows the long-term economic forecast used in the load forecast.

**Exhibit 3-7. Macroeconomic Long Term Forecast**

| Fiscal Year | Population (thousands of people) | GNP (Real Millions US dollars) | Manufacturing Employment (thousands of people) |
|---|---|---|---|
| 2018 | 3,143 | 5,251 | 70 |
| 2019 | 3,104 | 5,573 | 69 |
| 2020 | 3,084 | 5,632 | 70 |
| 2021 | 3,039 | 5,707 | 70 |
| 2022 | 2,995 | 5,792 | 70 |
| 2023 | 2,951 | 5,873 | 70 |
| 2024 | 2,910 | 5,941 | 71 |
| 2025 | 2,871 | 5,991 | 71 |
| 2026 | 2,833 | 6,029 | 71 |
| 2027 | 2,794 | 6,041 | 72 |
| 2028 | 2,756 | 6,038 | 72 |
| 2029 | 2,718 | 5,984 | 73 |
| 2030 | 2,681 | 5,949 | 73 |
| 2031 | 2,644 | 5,922 | 74 |
| 2032 | 2,609 | 5,897 | 74 |
| 2033 | 2,575 | 5,877 | 75 |
| 2034 | 2,541 | 5,862 | 75 |
| 2035 | 2,508 | 5,852 | 76 |
| 2036 | 2,476 | 5,847 | 77 |
| 2037 | 2,445 | 5,846 | 77 |
| 2038 | 2,414 | 5,849 | 78 |

Source: FOMB (population and GNP), Siemens for Manufacturing employment

### 3.1.5 Long Term Energy Forecast

Exhibit 3-8 shows Siemens forecasted gross energy sales by customer class. The forecast does not include any future energy efficiency and/or demand response programs and distributed generation (DG) in addition to current programs in place. The impact of those programs is addressed and modeled separately as discussed in later sections of this document. The forecast includes the impact of naturally occurring energy efficiency savings, such as more efficient household appliances, in as much these efficiency savings are embedded in the historical energy consumption data used to create the forecast.

**Exhibit 3-8. Gross Sales Demand by Customer Class**

| Fiscal Year | Residential Sales (GWh) | Commercial Sales (GWh) | Industrial Sales (GWh) | Agricultural Sales (GWh) | Public Lighting Sales (GWh) | Other Sales (GWh) | Total Sales (GWh) |
|---|---|---|---|---|---|---|---|
| 2019 | 5,472 | 7,962 | 1,491 | 26 | 315 | 35.6 | 15,301 |
| 2020 | 5,480 | 7,948 | 1,551 | 26 | 316 | 35.8 | 15,357 |
| 2021 | 5,473 | 7,917 | 1,635 | 26 | 317 | 35.9 | 15,403 |
| 2022 | 5,473 | 7,886 | 1,730 | 26 | 318 | 36.0 | 15,470 |
| 2023 | 5,470 | 7,856 | 1,822 | 27 | 320 | 36.2 | 15,530 |
| 2024 | 5,464 | 7,827 | 1,900 | 27 | 320 | 36.3 | 15,574 |
| 2025 | 5,451 | 7,801 | 1,960 | 27 | 321 | 36.3 | 15,595 |
| 2026 | 5,431 | 7,774 | 2,008 | 27 | 321 | 36.3 | 15,596 |
| 2027 | 5,396 | 7,747 | 2,028 | 27 | 320 | 36.2 | 15,554 |
| 2028 | 5,353 | 7,721 | 2,032 | 26 | 319 | 36.1 | 15,487 |
| 2029 | 5,284 | 7,695 | 1,984 | 26 | 316 | 35.7 | 15,341 |
| 2030 | 5,223 | 7,669 | 1,956 | 26 | 313 | 35.5 | 15,223 |
| 2031 | 5,168 | 7,644 | 1,937 | 26 | 311 | 35.2 | 15,120 |
| 2032 | 5,115 | 7,619 | 1,921 | 26 | 309 | 35.0 | 15,025 |
| 2033 | 5,065 | 7,596 | 1,910 | 26 | 307 | 34.8 | 14,939 |
| 2034 | 5,020 | 7,572 | 1,905 | 25 | 306 | 34.6 | 14,862 |
| 2035 | 4,978 | 7,549 | 1,905 | 25 | 304 | 34.5 | 14,796 |
| 2036 | 4,940 | 7,527 | 1,911 | 25 | 303 | 34.3 | 14,741 |
| 2037 | 4,905 | 7,506 | 1,921 | 25 | 302 | 34.2 | 14,694 |
| 2038 | 4,873 | 7,484 | 1,935 | 25 | 302 | 34.1 | 14,654 |
| CAGR | -0.61% | -0.32% | 1.38% | -0.23% | -0.23% | -0.23% | -0.23% |

Note: The sales forecasts reflect gross energy sales inclusive of existing EE programs. It does not include loses, PREPA's own use and auxiliary demand neither any future incremental EE and/or demand response programs.

Gross energy sales are projected to increase by 15% in fiscal year 2019 due to the projected, near-term recovery in the economy. However, over the full 20-year study period, gross energy sales are projected to decline at average of 0.23% per-year driven by the long-term decline in population and softening of the GNP growth after 2027. Among customer classes, the industrial class is the only customer class projected to have a positive average growth over the study period, at an average of 1.4% per-year, primarily driven by the projected economic growth through 2026. In contrast, the residential and commercial classes are projected to decline by an average of 0.6% and 0.3% per-year, mostly driven by the long-term decline in population.

Agriculture, public lightning and "other" are projected to decline in line with the overall system average of -0.23% per year. The public lighting forecast does not include the impact of a wide spread replacement of the current metal-vapor-based public lightning with LED light bulbs. LED replacement and other energy efficiency programs are addressed in a separate document; however, at the end of this report, Siemens provides a summary of the effects of energy efficiency programs on the load forecast.

Exhibit 3-9 illustrates the gross energy demand inclusive of the generation auxiliary loads, technical and non-technical loses, and PREPA's own use. The first column, gross energy sales, reflects the totals from **Error! Reference source not found.** PREPA's own use is assumed to stay constant through the forecast. The forecast includes no change in the auxiliary generation load. However, in the portfolio scenario analysis of the Integrated Resource Plan, future retirements are incorporated into the forecast and their corresponding impact on demand.

**Exhibit 3-9. Gross Energy Demand for Generation**

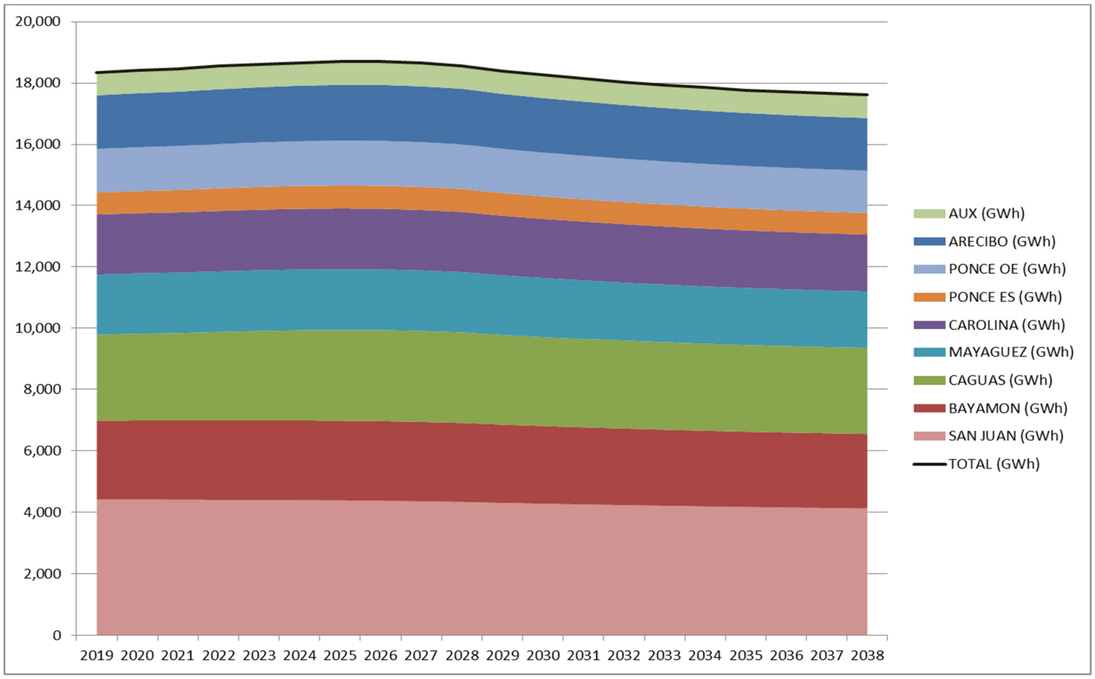
| Fiscal Year | Gross Energy Sales (GWh) | Technical Losses (GWh) | Non-Technical Losses (GWh) | Auxiliary (GWh) | PREPA Own Use (GWh) | Total Energy Demand (GWh) |
|---|---|---|---|---|---|---|
| 2019 | 15,301 | 1,438 | 827 | 751 | 34 | 18,351 |
| 2020 | 15,357 | 1,444 | 830 | 751 | 34 | 18,415 |
| 2021 | 15,403 | 1,448 | 832 | 751 | 34 | 18,469 |
| 2022 | 15,470 | 1,454 | 836 | 751 | 34 | 18,545 |
| 2023 | 15,530 | 1,460 | 839 | 751 | 34 | 18,613 |
| 2024 | 15,574 | 1,464 | 841 | 751 | 34 | 18,665 |
| 2025 | 15,595 | 1,466 | 842 | 751 | 34 | 18,689 |
| 2026 | 15,596 | 1,466 | 843 | 751 | 34 | 18,690 |
| 2027 | 15,554 | 1,462 | 840 | 751 | 34 | 18,642 |
| 2028 | 15,487 | 1,456 | 837 | 751 | 34 | 18,565 |
| 2029 | 15,341 | 1,442 | 829 | 751 | 34 | 18,397 |
| 2030 | 15,223 | 1,431 | 822 | 751 | 34 | 18,261 |
| 2031 | 15,120 | 1,421 | 817 | 751 | 34 | 18,144 |
| 2032 | 15,025 | 1,412 | 812 | 751 | 34 | 18,034 |
| 2033 | 14,939 | 1,404 | 807 | 751 | 34 | 17,935 |
| 2034 | 14,862 | 1,397 | 803 | 751 | 34 | 17,848 |
| 2035 | 14,796 | 1,391 | 799 | 751 | 34 | 17,772 |
| 2036 | 14,741 | 1,386 | 796 | 751 | 34 | 17,708 |
| 2037 | 14,694 | 1,381 | 794 | 751 | 34 | 17,654 |
| 2038 | 14,654 | 1,377 | 792 | 751 | 34 | 17,608 |
| CAGR | -0.23% | -0.23% | -0.23% | 0.00% | 0.00% | -0.22% |

To assess the geographical location of the demand above, as necessary for the modeling of the system, PREPA provided the composition of the load in term of customer classes (residential, commercial, industrial, etc.) by County which was used to map the forecast to each of the areas into which the system is modeled. Exhibit 3-10 and Exhibit 3-11 shows the resulting allocation of the Energy Demand for Generation above in tabular and graphic form.

**Exhibit 3-10. Gross Energy Demand for Generation by Area**

| Fiscal Year | ARECIBO (GWh) | BAYAMON (GWh) | CAGUAS (GWh) | CAROLINA (GWh) | MAYAGUEZ (GWh) | PONCE ES (GWh) | PONCE OE (GWh) | SAN JUAN (GWh) | AUX (GWh) | TOTAL (GWh) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2,019 | 1,748 | 2,558 | 2,818 | 1,956 | 1,961 | 719 | 1,422 | 4,417 | 751 | 18,351 |
| 2,020 | 1,759 | 2,566 | 2,840 | 1,961 | 1,966 | 724 | 1,429 | 4,418 | 751 | 18,415 |
| 2,021 | 1,771 | 2,571 | 2,866 | 1,965 | 1,969 | 729 | 1,436 | 4,411 | 751 | 18,469 |
| 2,022 | 1,787 | 2,579 | 2,898 | 1,970 | 1,974 | 736 | 1,445 | 4,406 | 751 | 18,545 |
| 2,023 | 1,801 | 2,585 | 2,927 | 1,975 | 1,978 | 742 | 1,453 | 4,401 | 751 | 18,613 |
| 2,024 | 1,813 | 2,590 | 2,951 | 1,978 | 1,981 | 746 | 1,460 | 4,394 | 751 | 18,665 |
| 2,025 | 1,820 | 2,591 | 2,968 | 1,979 | 1,981 | 750 | 1,464 | 4,385 | 751 | 18,689 |
| 2,026 | 1,824 | 2,589 | 2,978 | 1,978 | 1,979 | 751 | 1,466 | 4,374 | 751 | 18,690 |
| 2,027 | 1,821 | 2,581 | 2,975 | 1,971 | 1,972 | 750 | 1,462 | 4,357 | 751 | 18,642 |
| 2,028 | 1,815 | 2,569 | 2,965 | 1,962 | 1,963 | 747 | 1,457 | 4,337 | 751 | 18,565 |
| 2,029 | 1,794 | 2,544 | 2,930 | 1,945 | 1,945 | 739 | 1,442 | 4,307 | 751 | 18,397 |
| 2,030 | 1,779 | 2,524 | 2,903 | 1,930 | 1,931 | 732 | 1,430 | 4,280 | 751 | 18,261 |
| 2,031 | 1,766 | 2,506 | 2,882 | 1,917 | 1,918 | 727 | 1,420 | 4,256 | 751 | 18,144 |
| 2,032 | 1,755 | 2,490 | 2,862 | 1,905 | 1,905 | 722 | 1,411 | 4,233 | 751 | 18,034 |
| 2,033 | 1,744 | 2,475 | 2,845 | 1,894 | 1,894 | 717 | 1,403 | 4,211 | 751 | 17,935 |
| 2,034 | 1,736 | 2,461 | 2,831 | 1,885 | 1,884 | 714 | 1,396 | 4,191 | 751 | 17,848 |
| 2,035 | 1,728 | 2,449 | 2,820 | 1,876 | 1,875 | 710 | 1,390 | 4,172 | 751 | 17,772 |
| 2,036 | 1,723 | 2,439 | 2,812 | 1,868 | 1,867 | 708 | 1,385 | 4,155 | 751 | 17,708 |
| 2,037 | 1,719 | 2,430 | 2,806 | 1,862 | 1,860 | 706 | 1,381 | 4,139 | 751 | 17,654 |
| 2,038 | 1,715 | 2,422 | 2,802 | 1,856 | 1,854 | 705 | 1,378 | 4,124 | 751 | 17,608 |

**Exhibit 3-11. Graph of Gross Energy Demand for Generation by Area**




Source: Siemens

The IRP Regulation issued by the PREB requires the load forecast evaluation include:

- Comparisons of prior forecasts versus actual data
- An explanation of the cause of any significant deviation between the prior forecasts and the actual annual peak demand and energy that occurred
- An explanation of the impact that historical demand—side resources had on the prior load forecast.

Siemens believes the comparisons with actual data to recent forecasts have been rendered meaningless by structural changes in the island population, economy and energy consumption that have taken place as a result of Hurricane Maria. A more meaningful comparison is the significant changes resulting from Hurricane Maria to the forecasts. Exhibit 3-12Illustrates the differences in the customer class level energy sales forecasts developed for the 2015 IRP and the forecasts developed for this 2018 IRP. Exhibit 3-13 provides a comparison of the forecasted total energy sales from the 2015 IRP versus this 2018 IRP.

**Exhibit 3-12: Comparison of 2015 versus 2018 IRP Forecasted Class-Level Energy Sales**

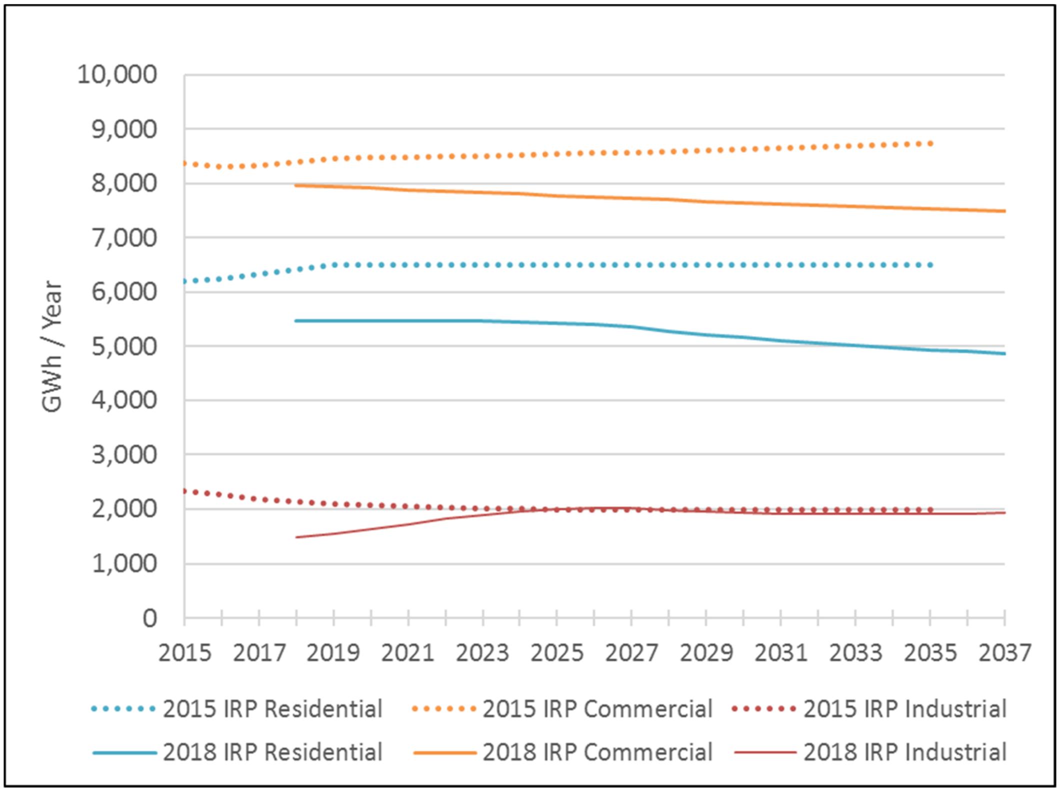
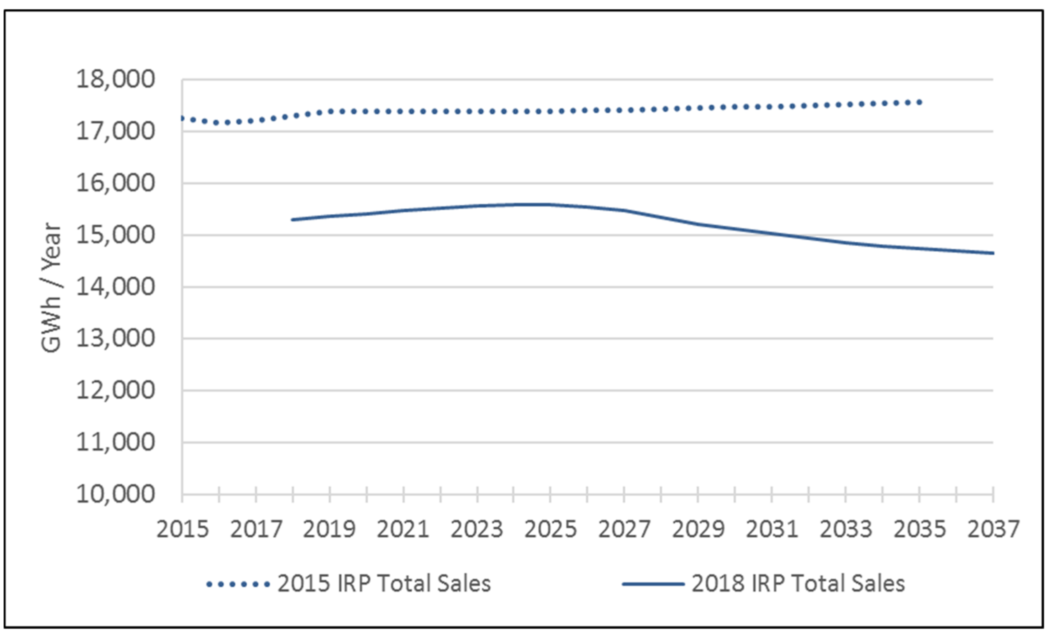



**Exhibit 3-13: Comparison of 2015 versus 2018 IRP Forecasted Total Energy Sales**

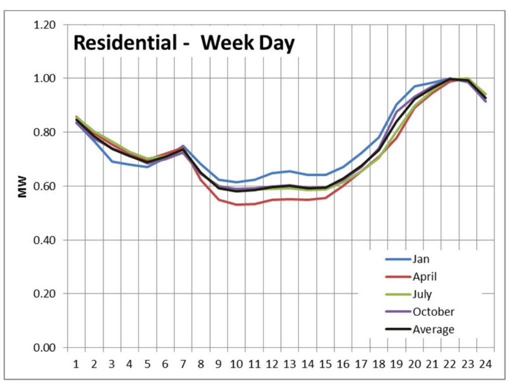


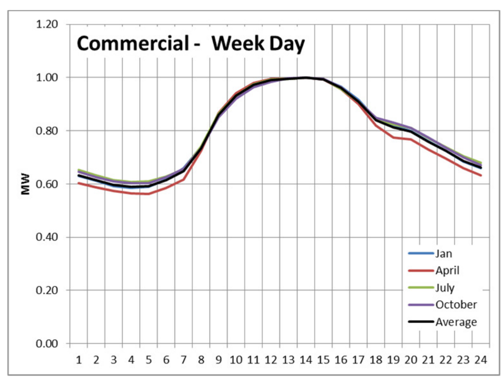
### 3.1.6 Long Term Peak Demand Forecast

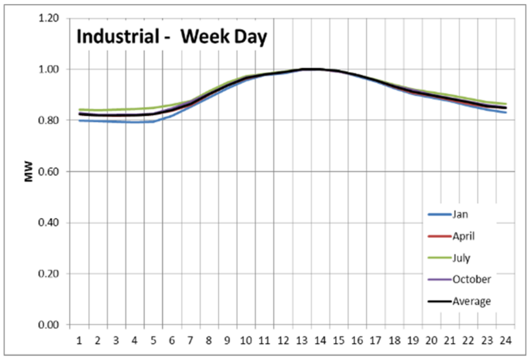
To estimate the peak demand associated with the energy forecast the expected load factors (i.e. the ratio of average demand to the peak demand) for each customer class was assessed along with the percentage of their peak demand that occurs at the time of the system peak (called Customer Class Coincidence Factor – CCCF – or Contribution to the Peak Factor). In principle, these factors would ordinarily be determined monthly, consistent with the monthly detail of the energy forecast and include an analysis of load factors and coincident factors over multiple years. However, for this study, a single annual average load factor value was used for each class due to the fact that: a) there was not a significant change in the hourly load shapes for the relevant customer classes across the year, b) the load factor can be volatile unless averages are used due to its dependence on the measured peak, c) only one-year worth of hourly load data by customer class was available. The inclusion of a stochastic distribution of energy forecasts, discussed in later sections of this report, serves to drive a large range of forecasted peak demand.

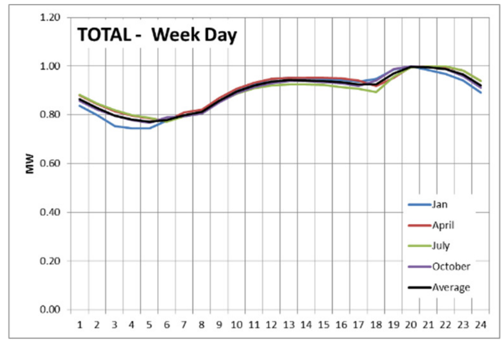
Exhibit 3-14 shows the normalized load shapes for the main customer classes (residential, commercial and industrial) that constitute the vast majority of the forecasted energy consumption as well as the system total. As can be observed, unlike the mainland U.S. where there are large changes in the shape from summer to winter, the Puerto Rico load shapes show little seasonal variation (residential shows the greatest variation). An average annual load factor represents a reasonable method to represent each customer class. Exhibit 3-14 also illustrates that there are two peaks a day, the first in the daytime hours driven by commercial and industrial loads and the second an evening peak driven by the residential load. The evening peak is the higher of the two daily peaks. Thus, the residential customers peak coincides with the system peak (CCCF =1) while the industrial and commercial customers have a load below their respective class level peak loads at the time of the system peak load (CCCF < 1).

**Exhibit 3-14. Normalized Load Shapes for main Customer Classes and System Total**






Based on the hourly information provided by PREPA, Siemens estimated the Customer Class Load Factors and Customer Class Coincidence Factors (% of the Customer Class peak at the time of the System Peak) shown in Exhibit 3-15.

**Exhibit 3-15. Selected Load Factors and Customer Class Coincidence Factor**

| Customer Class | Customer Class Load Factor % | Customer Class Coincidence Factor % |
|---|---|---|
| Residential | 66.9% | 100% |
| Commercial | 70.2% | 70% |
| Industrial | 81.2% | 85% |
| Lighting | 49.3% | 100% |
| Other | 73.6% | 80% |
| Agriculture | 46.8% | 32% |

Using the values above and the forecasted energy consumption by customer class, the demand at the time of system peak can be forecasted. To this forecast peak load the following elements of load were added:

a) The effect of the technical transmission and distribution technical loses using a correction to convert energy losses into capacity losses based on the load factor[13],
b) The non-technical losses using same load factor and CCCF values as the residential load,
c) PREPA's own consumption using an estimated load factor based on historical values, and
d) The effects of the consumption on the generating plants auxiliary services.

[13] Capacity Losses % = (Energy Losses %) / (0.3+0.7*LF)

Exhibit 3-16 shows the energy demand and peak demand for generation, inclusive of the factors indicated above (technical and non-technical losses, auxiliary demand and PREPA's own use). Exhibit 3-16 does not include the impact of future energy efficiency (EE), demand response programs or DG. It should be noted that while DG is modeled separately as a source, it does have an impact in reducing the T&D technical losses and this is accounted for in the final forecast together with the impacts of EE, as is discussed later in this report. Demand Response is a resource used to provide reserves and it does not affect the load forecast.

Peak demand (before EE) is projected to decline by 0.24% per year. The lower rate of peak growth relative to the energy demand is a consequence of more modest growth in the residential demand compared to commercial demand and the corresponding contribution of each class to system peak demand. Commercial load peaks during the day, while the residential load peaks in the evening (sometimes very late), the latter driving the system peak. A reduction in residential load results in a reduction in the evening peak and an increase in the overall system load factor.

**Exhibit 3-16. Gross Generation**

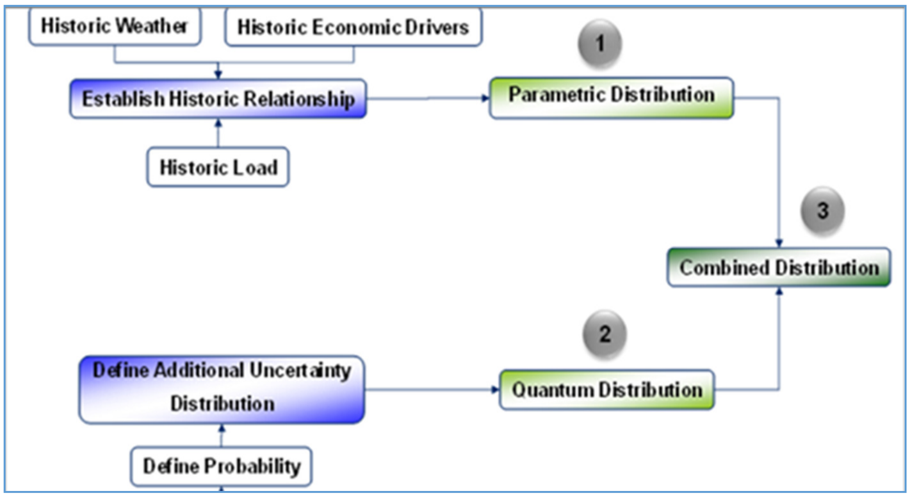
| Fiscal Year | Energy (GWh) | Peak Demand (MW) | Load Factor (%) |
|---|---|---|---|
| **2019** | 18,353 | 2,791 | 75.1% |
| **2020** | 18,417 | 2,799 | 75.1% |
| **2021** | 18,471 | 2,805 | 75.2% |
| **2022** | 18,547 | 2,815 | 75.2% |
| **2023** | 18,615 | 2,823 | 75.3% |
| **2024** | 18,666 | 2,829 | 75.3% |
| **2025** | 18,691 | 2,831 | 75.3% |
| **2026** | 18,691 | 2,830 | 75.4% |
| **2027** | 18,644 | 2,822 | 75.4% |
| **2028** | 18,567 | 2,810 | 75.4% |
| **2029** | 18,399 | 2,785 | 75.4% |
| **2030** | 18,264 | 2,765 | 75.4% |
| **2031** | 18,146 | 2,748 | 75.4% |
| **2032** | 18,037 | 2,731 | 75.4% |
| **2033** | 17,938 | 2,716 | 75.4% |
| **2034** | 17,851 | 2,703 | 75.4% |
| **2035** | 17,775 | 2,692 | 75.4% |
| **2036** | 17,711 | 2,682 | 75.4% |
| **2037** | 17,657 | 2,673 | 75.4% |
| **2038** | 18,353 | 2,666 | 75.4% |
| **CAGR** | **-0.22%** | **-0.24%** | |

Note: Forecast includes technical and non-technical losses, auxiliary demand and PREPA's own use. The forecast does not include the impact of future energy efficiency and/or demand response programs.

### 3.1.7 Stochastic Distribution

To generate scenarios for energy growth, Siemens developed statistical distributions based on deterministic energy forecasts. The process involves two steps: the first involves developing parametric distributions around key fundamental variables that could present more volatility in the future (weather and economic performance in Puerto Rico). Siemens utilized historical data to develop 2,000 scenarios for weather and GDP that were fed into the econometric regression model to determine 2,000 iterations of average and high energy growth. The second step involves developing quantum distributions, which incorporate future uncertainties not captured by the historical data. The overall process is summarized by the flow chart in Exhibit 3-17 below.

**Exhibit 3-17. Stochastic Process for Energy Forecasts**




### 3.1.8 Parametric Distributions

The development of stochastics is based on building probability distributions around the deterministic energy forecast. To produce probability distributions of the energy forecast, Siemens propagates three independent random paths: CDD, GDP, and a residual.

- To produce reasonable weather data projections, Siemens sampled 17-years of monthly historical weather data based on CDD for 2000-2017.
- GDP is assumed to follow a Geometric Brownian Motion. This means that there exists a normal distribution with constant mean and variance that describes how the GDP could behave at any time in the future. The process is developed using historical quarterly GDP data for 2000-2017.
- Finally, to account for unexplained variation in the observed data, Siemens adds a normally distributed residual with mean zero and standard deviation equal to the root mean squared error from a stepwise regression.

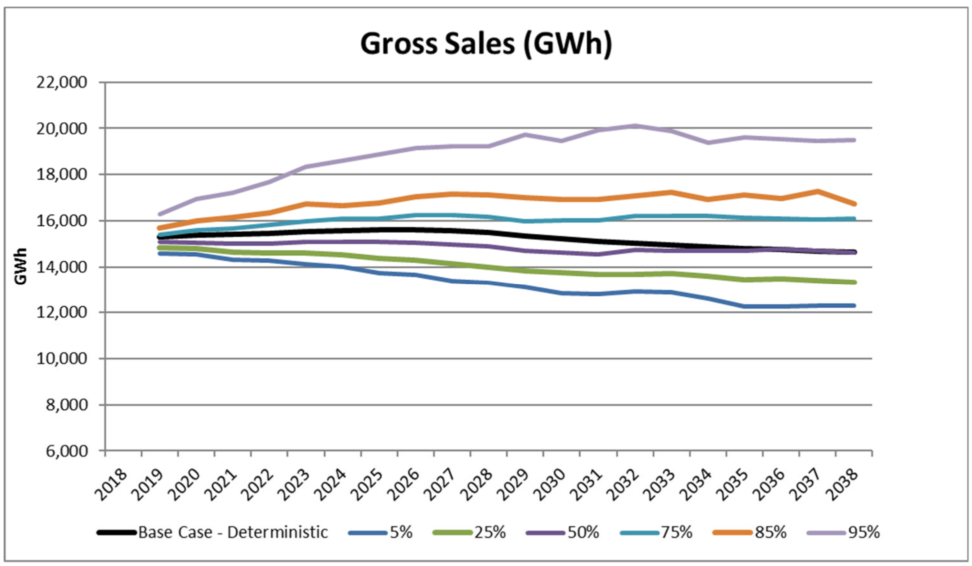
Based on historical volatility, 2,000 distributions of these variables are developed and used in the stepwise regression model to develop an intermediate distribution of average and peak energy forecast distributions.

### 3.1.9 Quantum Distribution: Additional Variability

It is Siemens' opinion that future energy demand may differ substantially from past energy demand. To account for this possibility, Siemens adds an additional "Quantum Distribution" to its empirically derived distribution. The 5th percentile of this distribution reflects a low growth scenario (i.e. higher degree of DSM and DG penetration). The upper tail of this distribution (95th Percentile) is weighted to match Siemens' analysis of historical high periods of energy growth and to capture other events such as higher penetration of air conditioning loads and rising demand from electric vehicles. Using these high and low growth scenarios, Siemens generates a distribution of energy forecasts using statistical techniques. This distribution is superimposed on the parametric distribution obtained in the step discussed above. The resulting distribution is considered the final average and peak energy forecast distribution (2,000 iterations).

Exhibit 3-18 shows an illustrative stochastic distribution of gross sales for planning purposes.

**Exhibit 3-18. Stochastic Distribution of Gross Sales**




Note: The sales forecasts reflect gross energy sales inclusive of existing EE programs. It does not include loses, PREPA's own use and auxiliary demand neither any future incremental EE and/or demand response programs.

The mean path corresponds to the average of 2,000 iterations of combinations of the stochastic input drivers. The percentile bands are not energy paths but instead represent the likelihood that the sales could be at or below that level in a given year. For example, in 2025 there is a 95% likelihood that energy sales will be at or below 18,885 MWh. Also, in 2025, there is a 5% chance that energy sales will be at or below 14,352 MWh.

Based on its assessment of the results of the stochastic distributions, Siemens chose to use the 25th percentile as the low case and the 85th percentile as the high case for all scenarios. In general, the 75th and the 25th percentile represent approximately one standard deviation above and below the mean on a normal distribution. However, load tends to follow a log normal distribution, which tends to have an upward bias. As result, Siemens considered that using the 85th percentile would be more reasonable for the high case.

The 85th and 25th percentiles do not represent extreme cases either but a reasonable high and low forecast for planning purposes. The extreme high and low would typically be defined by the 95th percentile and 5th percentile, respectively.

To describe the factors that could give rise to the extreme high and low forecasts mathematically obtained above, Siemens developed and very optimistic scenario and a very pessimistic scenario for the macroeconomic parameters driving the forecast: GNP and population.

The very optimistic case assumes that the structural reforms in Puerto Rico are highly successful and the GNP after hitting a low in 2018 bounces back at a rate 50% faster than Moody's forecast for two years as federal funds are invested in the island. From 2020 onwards, the Puerto Rico economy recovers to its pre-2006 potential and the GNP grows at 75% of the US GDP forecast growth rate – see Exhibit 3-19. Consistent with this economic outlook, there is initially a population drop following the U.S. Census forecast until 2019 and from 2020 onwards, as the Puerto Rico economy starts to grow, the population outflow reduces to only 25% of the yearly attrition in the U.S. Census forecast – see Exhibit 3-20.

The very pessimistic case, assumes that the structural reforms do not take place and there is limited federal funds invested in the island, resulting in a continuation of the GNP decline at 1% per year in line with the historical post 2006 decline. Consistent with this outlook the population decline accelerates and after an initial drop in line with FOMB forecasts, from 2019 onwards it declines at 1.5 times yearly attrition in this forecast.

**Exhibit 3-19. GNP Scenarios**

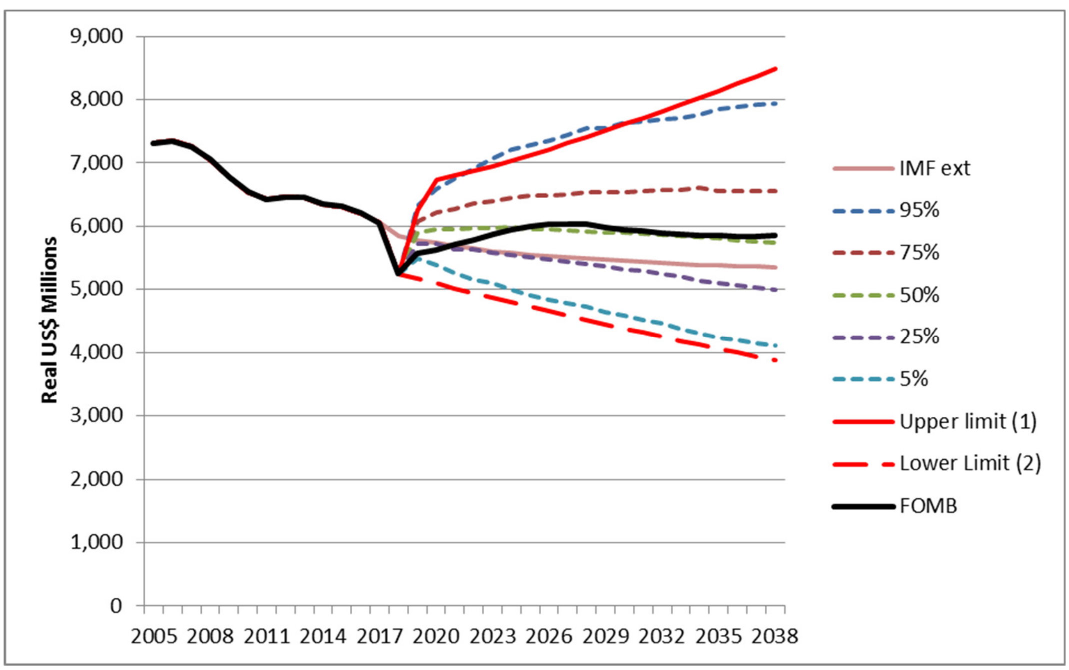
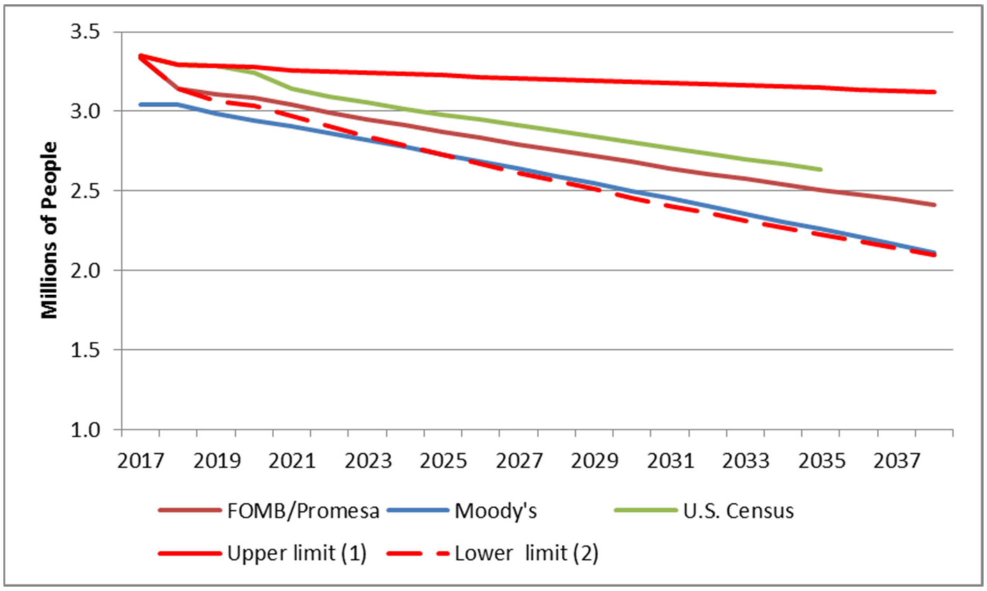


**Exhibit 3-20. Population Scenarios**




The resulting gross sales forecasts for the Upper and Lower limits are shown in Exhibit 3-21. In the high case scenario, gross energy sales increase at 1.34% per-year, with sales reaching 20,672 GWh by 2038 – 41% higher than the reference case. In the low case scenario, gross energy sales decline at 1.50% per-year reaching 11,033 GWh by 2038, 75% below the reference case level. The industrial customer class has the most upside or downside potential driven by changes in the GNP and/or population from all three classes, with sales growing at 5.6% per-year in the high case or declining at 5.2% per-year in the low case. The forecasts below do not include the impact of new energy efficiency programs.

**Exhibit 3-21. Gross Sales Forecast Scenarios – High and Low Cases**

| Fiscal Year | Gross Energy Sales Reference (GWh) | Gross Energy Sales Very Optimistic (GWh) | Gross Energy Sales Very Pessimistic (GWh) | Gross Energy Sales High Case (GWh) | Gross Energy Sales Low Case (GWh) |
|---|---|---|---|---|---|
| 2019 | 15,301 | 16,043 | 14,703 | 15,670 | 14,844 |
| 2020 | 15,357 | 17,400 | 14,470 | 16,001 | 14,811 |
| 2021 | 15,403 | 17,869 | 14,257 | 16,166 | 14,636 |
| 2022 | 15,470 | 17,976 | 14,015 | 16,358 | 14,596 |
| 2023 | 15,530 | 18,102 | 13,776 | 16,730 | 14,588 |
| 2024 | 15,574 | 18,239 | 13,545 | 16,642 | 14,514 |
| 2025 | 15,595 | 18,385 | 13,325 | 16,755 | 14,352 |
| 2026 | 15,596 | 18,540 | 13,112 | 17,024 | 14,292 |
| 2027 | 15,554 | 18,699 | 12,901 | 17,136 | 14,148 |
| 2028 | 15,487 | 18,863 | 12,695 | 17,114 | 13,989 |
| 2029 | 15,341 | 19,030 | 12,498 | 16,998 | 13,831 |
| 2030 | 15,223 | 19,200 | 12,304 | 16,939 | 13,740 |
| 2031 | 15,120 | 19,372 | 12,118 | 16,932 | 13,664 |
| 2032 | 15,025 | 19,547 | 11,939 | 17,078 | 13,690 |
| 2033 | 14,939 | 19,725 | 11,765 | 17,235 | 13,702 |
| 2034 | 14,862 | 19,906 | 11,597 | 16,923 | 13,582 |
| 2035 | 14,796 | 20,091 | 11,439 | 17,113 | 13,435 |
| 2036 | 14,741 | 20,280 | 11,295 | 16,976 | 13,476 |
| 2037 | 14,694 | 20,474 | 11,160 | 17,270 | 13,390 |
| 2038 | 14,654 | 20,672 | 11,033 | 16,719 | 13,323 |
| CAGR | -0.23% | 1.34% | -1.50% | 0.34% | -0.57% |

Part
4

# Existing Resources

## 4.1 Existing Generation Resources and Distributed Generation

Siemens reviewed cost and technical characteristics and operating status on PREPA's existing generation resources and Power Purchase and Operating Agreements (PPOAs) as inputs to the IRP. The thermal supply-side resources section of this report (Appendix 5 – New and Existing Supply-Side Resources Supplemental Data) includes a review of the operating characteristics of the generation units along with their operating costs.

On the other hand, Part 6 – New Resources Options of this report presents the new resources considered in the IRP and Appendix 4 – Demand Side Resources presents a discussion of the demand side resources including distributed generation, energy efficiency, demand response, and CHP (Combined Heat and Power).

### 4.1.1 PREPA's Existing Generation Facilities

Siemens reviewed and discussed PREPA's existing generation resources, including the units' condition and operating status, with PREPA and its advisors. As a result of this review, 39 existing generation units, with a total capacity of 5,010 MW, were determined to be in acceptable operating condition for consideration as available resources in this IRP.

Exhibit 4-1 presents the operational parameters including technology (i.e., steam turbine [ST], simple cycle combustion turbines, referenced as gas turbines per PREPA conventions [GT], and combined cycle gas turbine [CC]), rated capacity[14], fuel type, heat rate, fixed operating and maintenance costs (FOM), and variable operating and maintenance costs (VOM) of the existing generation resources in 2018 dollars.

[14] The maximum capacities considered in the study are based on information provided by PREPA. These capacities are smaller than the nominal capacities in the case of San Juan 5 and 6 CC (nominal capacity of 220 MW each), Aguirre CC 1 and 2 (nominal capacity of 296 MW each), Mayagüez GT (nominal capacity of 55 MW each), and the hydro generation (nominal capacity of 105 MW). The total nominal capacity of existing PREPA generation resources is 5,213 MW.

### Exhibit 4-1. PREPA Existing Units Included in the IRP

| | Generation Units | Maximum Modeled Capacity (MW) | Fuel | Heat Rate at Max. Capacity (BTU/kWh) | FOM (2018 $/kW-year) | VOM (2018 $/MWh) |
|---|---|---|---|---|---|---|
| MATS Affected Units | Aguirre 1 ST | 450 | No. 6 fuel oil | 9,600 | 32.04 | 2.25 |
| | Aguirre 2 ST | 450 | No. 6 fuel oil | 9,700 | 32.04 | 2.25 |
| | Costa Sur 5 ST | 410 | Natural gas | 9,747 | 35.96 | 2.72 |
| | Costa Sur 6 ST | 410 | Natural gas | 9,747 | 35.96 | 2.72 |
| | Palo Seco 3 ST | 216 | No. 6 fuel oil | 9,725 | 46.47 | 4.95 |
| | Palo Seco 4 ST | 216 | No. 6 fuel oil | 9,725 | 46.47 | 4.95 |
| | San Juan 7 ST | 100 | No. 6 fuel oil | 10,497 | 49.02 | 2.93 |
| | San Juan 8 ST | 100 | No. 6 fuel oil | 10,445 | 49.02 | 2.93 |
| Combined Cycle | Aguirre 1 CC | 260 | Diesel | 11,140 | 22.64 | 6.79 |
| | Aguirre 2 CC | 260 | Diesel | 11,140 | 22.64 | 6.79 |
| | San Juan 5 CC | 200 | Diesel | 7,625 | 27.40 | 2.22 |
| | San Juan 6 CC | 200 | Diesel | 7,853 | 27.40 | 2.22 |
| Gas Turbine | Cambalache 2 GT | 83 | Diesel | 11,549 | 24.44 | 5.52 |
| | Cambalache 3 GT | 83 | Diesel | 11,549 | 24.44 | 5.52 |
| | Mayagüez 1 GT | 50 | Diesel | 9,320 | 10.64 | 6.40 |
| | Mayagüez 2 GT | 50 | Diesel | 9,320 | 10.64 | 6.40 |
| | Mayagüez 3 GT | 50 | Diesel | 9,320 | 10.64 | 6.40 |
| | Mayagüez 4 GT | 50 | Diesel | 9,320 | 10.64 | 6.40 |
| | Daguao 2 GTs | 42 | Diesel | 14,400 | 26.54 | 20.19 |
| | Palo Seco GT11 & GT12 | 42 | Diesel | 14,400 | 26.54 | 20.19 |
| | Palo Seco GT21 & GT 22 | 42 | Diesel | 14,400 | 26.54 | 20.19 |
| | Palo Seco GT31 & GT32 | 42 | Diesel | 14,400 | 26.54 | 20.19 |
| | Aguirre GT21 & GT22 | 42 | Diesel | 14,400 | 26.54 | 20.19 |
| | Costa Sur GT11 & GT12 | 42 | Diesel | 14,400 | 26.54 | 20.19 |
| | Jobos GT11 & GT12 | 42 | Diesel | 14,400 | 26.54 | 20.19 |
| | Yabucoa GT11 & GT12 | 42 | Diesel | 14,400 | 26.54 | 20.19 |
| | Vega Baja GT11 & GT12 | 42 | Diesel | 14,400 | 26.54 | 20.19 |
| Hydro | Hydro | 34 | Water | N/A | N/A | N/A |
| IPP Units | AES Coal 2 Units | 454 | Coal | 9,791 | 79.46 | 7.23 |
| | EcoEléctrica Plant | 507 | Natural gas | 7,497 | 189.34 | 0.00 |
| | **Total** | **5,010** | | | | |

Source: PREPA, Siemens.

It was jointly decided that 11 existing generation units, with a total capacity of 707 MW, were not in sufficient operational condition for inclusion as a generation resource in this IRP. A summary of the excluded units is shown below:

### Exhibit 4-2. PREPA Existing Units Excluded from the IRP

| | Generation Units | Capacity (MW) |
|---|---|---|
| Steam Turbine (MATS Affected) | Costa Sur 3 ST | 85 |
| | Costa Sur 4 ST | 85 |
| | Palo Seco 1 ST | 85 |
| | Palo Seco 2 ST | 85 |
| | San Juan 9 ST | 100 |
| | San Juan 10 ST | 100 |
| Gas Turbine | Cambalache 1 GT | 83 |
| **Total** | | **623** |

Source: PREPA, Siemens.

### 4.1.1.1 Steam Turbines (ST)

PREPA has a total of 14 ST units with a total capacity of 2,892 MW located at four sites, Palo Seco (4 units, 602 MW) and San Juan (4 units, 400 MW) in the north; Aguirre (2 units, 900 MW) and Costa Sur (4 units, 990 MW) in the south. All the ST units are subject to Mercury and Air Toxics Standards (MATS) compliance requirements. A total of 6 of the 14 ST units, 2 each at Palo Seco, San Juan and Costa Sur, as listed in Exhibit 4-2, were excluded from resources for this IRP due to their age and current non-operational condition.

The remaining eight MATS-affected units, with a total capacity of 2,352 MW, were operational and included in this IRP. These ST units are located at four sites including Palo Seco (2 units, 432 MW), and San Juan (2 units, 200 MW) in the north; and Aguirre (2 units, 900 MW), and Costa Sur (2 units, 820 MW) in the south. The Costa Sur ST units 5&6 are MATS compliant and have dual fuel capability, which can also burn No. 6 fuel oil but currently burn 100 percent natural gas. Exhibit 4-3 shows the unit level parameters of the eight ST units included in the IRP.

**Exhibit 4-3. ST Unit Parameters (Aguirre, Costa Sur, Palo Seco, San Juan)**

| Parameters | Unit | Aguirre ST | | Costa Sur ST | |
|---|---|---|---|---|---|
| | | Unit 1 | Unit 2 | Unit 5 | Unit 6 |
| Fuel | Type | No. 6 fuel oil | No. 6 fuel oil | Natural Gas | Natural Gas |
| Maximum Capacity | MW | 450 | 450 | 410 | 410 |
| Minimum Capacity | MW | 200 | 200 | 180 | 180 |
| Fixed O&M Expense | 2018 $/kW-year | 32.04 | 32.04 | 35.96 | 35.96 |
| Variable O&M Expense | 2018 $/MWh | 2.25 | 2.25 | 2.72 | 2.72 |
| Heat Rate at Maximum Capacity | MMBtu/MWh | 9.60 | 9.70 | 9.75 | 9.75 |
| Heat Rate at Minimum Capacity | MMBtu/MWh | 9.94 | 10.16 | 9.93 | 10.07 |
| Forced Outage | % | 20 | 20 | 2 | 4 |
| Minimum Downtime | Hours | 48 | 48 | 48 | 48 |
| Minimum Runtime | Hours | 720 | 720 | 720 | 720 |
| Ramp Up Rate | MW/minute | 5 | 5 | 5 | 5 |
| Ramp Down Rate | MW/minute | 5 | 5 | 5 | 5 |

| Parameters | Unit | Palo Seco ST | | San Juan ST | |
|---|---|---|---|---|---|
| | | Unit 3 | Unit 4 | Unit 7 | Unit 8 |
| Fuel | Type | No. 6 fuel oil | No. 6 fuel oil | No. 6 fuel oil | No. 6 fuel oil |
| Maximum Capacity | MW | 216 | 216 | 100 | 100 |
| Minimum Capacity | MW | 130 | 130 | 70 | 70 |
| Fixed O&M Expense | 2018 $/kW-year | 46.47 | 46.47 | 49.02 | 49.02 |
| Variable O&M Expense | 2018 $/MWh | 4.95 | 4.95 | 2.93 | 2.93 |
| Heat Rate at Maximum Capacity | MMBtu/MWh | 9.73 | 9.73 | 10.50 | 10.45 |
| Heat Rate at Minimum Capacity | MMBtu/MWh | 10.35 | 10.35 | 10.50 | 10.50 |
| Forced Outage | % | 42 | 42 | 15 | 15 |
| Minimum Downtime | Hours | 48 | 48 | 48 | 48 |
| Minimum Runtime | Hours | 720 | 720 | 720 | 720 |
| Ramp Up Rate | MW/minute | 3 | 3 | 3 | 3 |
| Ramp Down Rate | MW/minute | 3 | 3 | 3 | 3 |

Note: Aguirre ST and Costa Sur ST units have an emergency minimum capacity of 150 MW and 100 MW respectively.
Source: PREPA, Filsinger Energy Partners, Siemens.

The minimum capacity levels correspond to the minimum output that would still allow the units to return to a regulating operating mode within the hour, according to PREPA operations. There are lower capacity levels (e.g. Costa Sur ST 5&6 at 100 MW and Aguirre ST 1&2 at 150 MW), but these lower capacities would require multiple hours for the units to return to regulating operating mode.

The minimum run time reported was defined by PREPA's operations team to prevent the units from weekly cycling as was observed in prior studies that included high levels of renewable penetration.

The reported heat rates correspond to the values currently used in PREPA's models, adjusted if necessary for the reduced operating limits. These heat rates are reasonable for the technologies considered and are the best information available at this time.

For the forced outage assumption, Siemens reviewed the reported forced outage statistics for each unit from 2011 to October 2016 (reported Forced Outage Factor) in addition to the forced outage rate (FOR) currently used in PREPA's models and the recent experience with the units

Siemens increased the outage rate of Aguirre ST 1&2 from 4 percent in PREPA's existing models to 20 percent based on both the increase in forced outages experienced during 2010-2016 and the overall unit's condition. Costa Sur ST 5 was left unchanged at 2 percent and Costa Sur ST 6 was increased slightly from 3 percent to 4 percent. Costa Sur units 5&6 are expected to be thoroughly inspected and repaired.

Palo Seco ST units 3and 4 have had fairly poor performance and Siemens increased the FOR to 42% to be conservative and in line with the 45% availability observed. Finally, San Juan ST 7&8 outage rates were modeled at 15% to reflect 70% observed availability.

Based on discussions with PREPA and its advisors, Siemens excluded Costa Sur ST 3&4, Palo Seco ST 1&2 and San Juan ST 9&10 with a total of 540 MW from the IRP study, because these units are not in acceptable operating condition, are not in MATS compliance, and would require large investments that do not appear to be economic, to achieve MATS compliance and working condition.

#### 4.1.1.2 Combined Cycles (CC)

PREPA's four Combined Cycle (CC) units run on diesel. These units include Aguirre 1&2 CC (260 MW each) and San Juan 5&6 CC (200 MW each) with a total capacity of 920 MW. The Aguirre CC units went into commercial operation in 1975-1976 and are inefficient with very low historical dispatch levels. The nominal capacity of these units is 296 MW each, but this has been limited to 260 MW in this study[15]. It was assumed that these units would likely be retired early in the IRP but were left in to allow the IRP modeling to determine their continue economics in comparisons with alternative resources.

San Juan 5&6 CC units (also known as the San Juan Repower) began commercial operation in 2008 and are F Class CCs with a heat rate of 7,625 Btu/kWh and 7,853 Btu/kWh, respectively. These

[15] The maximum capacities considered in the study are based on information provided by PREPA.

units serve as an important generation resource operating in the north of the island. Their nominal capacity is 220 MW per unit, but this is limited to 200 MW in this study.

Exhibit 4-4 shows the unit level parameters of the four CC units included in the IRP. The heat rates correspond to the modeled values and it is important to note that these units should preferably be able to cycle daily if necessary to integrate renewable generation. However, as shown below PREPA has determined that the current minimum run time is 120 hours (5 days) which would allow these units to cycle weekly and be off only during the weekends.

The historical outage factors (2010 to 2016) for the Aguirre CC show values on the order of 2 percent for the Aguirre CC Unit 1 and 10 percent for Aguirre CC Unit 2, possibly due to its relatively low dispatch. However, the outage factor for these units was left at 20 percent considering their recent performance, as Siemens noted that Aguirre CC unit 2 had fairly poor performance with 33 percent steam turbine outage in 2015 and 20 percent outage in 2016. For San Juan CC, history has shown relatively poor availability in both units but better than the prior modeled 20 percent for San Juan unit 5 and worse for San Juan unit 6 (10 percent used in prior modeling). Thus, both units are modeled in this IRP at 18 percent forced outage rate, in line with the historical values.

**Exhibit 4-4. CC Units Parameters (Aguirre and San Juan)**

| Parameters | Unit | Aguirre CC | | San Juan CC | |
|---|---|---|---|---|---|
| | | Unit 1 | Unit 2 | Unit 5 | Unit 6 |
| Fuel | Type | Diesel | Diesel | Diesel | Diesel |
| Maximum Capacity | MW | 260 | 260 | 200 | 200 |
| Minimum Capacity | MW | 46 | 46 | 155 | 155 |
| Fixed O&M Expense | 2018 $/kW-year | 22.64 | 22.64 | 27.40 | 27.40 |
| Variable O&M Expense | 2018 $/MWh | 6.79 | 6.79 | 2.22 | 2.22 |
| Heat Rate at Maximum Capacity | MMBtu/MWh | 11.14 | 11.14 | 7.63 | 7.85 |
| Heat Rate at Minimum Capacity | MMBtu/MWh | 11.42 | 11.42 | 8.46 | 8.86 |
| Forced Outage | % | 20 | 20 | 18 | 18 |
| Minimum Downtime | Hours | 0 | 0 | 48 | 48 |
| Minimum Runtime | Hours | 2 | 2 | 120 | 120 |
| Ramp Up Rate | MW/minute | 5 | 5 | 3 | 3 |
| Ramp Down Rate | MW/minute | 5 | 5 | 3 | 3 |

Source: PREPA, Filsinger Energy Partners, Siemens.

### 4.1.1.3 Gas Turbines

Out of the 25 GT units, 24 units, with a total capacity of 743 MW, are included in the IRP. The GTs include Cambalache GT 2&3 (82.5 MW each), Mayagüez GT 1 through 4 (50 MW each), and nine pairs of distributed GTs (21 MW each) spread across the island. The Mayagüez units are four aero-derivative gas turbines with relatively good efficiency. The distributed GT's (21 MW each) include pairs of two units located: Daguao (2x21), Palo Seco (6x21), Aguirre (2x21), Costa Sur (2x21), Jobos (2x21), Yabucoa (2x21), and Vega Baja (2x21). These nine pair of distributed units, while in operating condition, are fairly old and have very poor heat rates. Fourteen of these units are retired early in the IRP capacity expansion plan and replaced by new peakers.

Based on discussions with PREPA and its advisors, Cambalache GT 1 will be excluded from the IRP because it is not planned to be returned to operating condition in the foreseeable future. The two 21 MW GTs at Aguirre and two 21 MW GTs at Costa Sur are necessary to provide black-start capability to their respective combined cycle and steam turbine at each location. These gas turbines can only be retired after new units are installed with black-start capability.

Exhibit 4-5 shows the unit level parameters of the 24 GT units considered in the IRP. The heat rates and forced outages are as modeled in the PREPA's models. The distributed GTs and the Mayagüez units can cycle with zero downtime and runtime.

**Exhibit 4-5. GT Units Parameters (Cambalache, Mayagüez and Nine Pairs of Distributed GT units)**

| Parameters | Unit | Cambalache CT | | GT Units |
|---|---|---|---|---|
| | | Unit 2 | Unit 3 | Each Unit |
| Fuel | Type | Diesel | Diesel | Diesel |
| Maximum Capacity | MW | 83 | 83 | 21 |
| Minimum Capacity | MW | 50 | 50 | 21 |
| Fixed O&M Expense | 2018 $/kW-year | 24.44 | 24.44 | 26.54 |
| Variable O&M Expense | 2018 $/MWh | 5.52 | 5.52 | 20.19 |
| Heat Rate at Maximum Capacity | MMBtu/MWh | 11.55 | 11.55 | 14.40 |
| Heat Rate at Minimum Capacity | MMBtu/MWh | 11.55 | 11.55 | 14.40 |
| Forced Outage | % | 10.0 | 10.0 | 15 |
| Minimum Downtime | Hours | 7 | 7 | 0 |
| Minimum Runtime | Hours | 7 | 7 | 0 |
| Ramp Up Rate | MW/minute | 2 | 2 | 2 |
| Ramp Down Rate | MW/minute | 2 | 2 | 2 |

| Parameters | Unit | Mayagüez CT | | | |
|---|---|---|---|---|---|
| | | Unit 1 | Unit 2 | Unit 3 | Unit 4 |
| Fuel | Type | Diesel | Diesel | Diesel | Diesel |
| Maximum Capacity | MW | 50 | 50 | 50 | 50 |
| Minimum Capacity | MW | 25 | 25 | 25 | 25 |
| Fixed O&M Expense | 2018 $/kW-year | 10.64 | 10.64 | 10.64 | 10.64 |
| Variable O&M Expense | 2018 $/MWh | 6.40 | 6.40 | 6.40 | 6.40 |
| Heat Rate at Maximum Capacity | MMBtu/MWh | 9.32 | 9.32 | 9.32 | 9.32 |
| Heat Rate at Minimum Capacity | MMBtu/MWh | 11.20 | 11.20 | 11.20 | 11.20 |
| Forced Outage | % | 9 | 9 | 9 | 9 |
| Minimum Downtime | Hours | 0 | 0 | 0 | 0 |
| Minimum Runtime | Hours | 0 | 0 | 0 | 0 |
| Ramp Up Rate | MW/minute | 6 | 6 | 6 | 6 |
| Ramp Down Rate | MW/minute | 6 | 6 | 6 | 6 |

Source: PREPA, Filsinger Energy Partners, Siemens.

#### 4.1.1.4 Hydro

PREPA has 21 hydroelectric generating units at 11 generating facilities for a total installed nameplate capacity of 105 MW. However, some of these units are not operational, or are underutilized due to staffing and funding shortages resulting in deferred maintenance issues. The operational units total 34 MW with a capacity factor of less than 20 percent as of the first quarter of 2018. In an effort to alternative methods that could economically increase the output and continuing operation from these clean hydroelectric resources, PREPA issued a Request for Proposal (RFP) regarding long-term lease and energy sales agreement for their hydroelectric power plants[16]. Exhibit 4-6 shows a

[16] REQUEST FOR PROPOSALS: Long-Term Lease and Energy Sales Agreement(s) for Hydroelectric Power Plants Owned by: Puerto Rico Electric Power Authority

scenario to increase hydroelectric contribution to 70 MW, assuming a high-level estimate of a total of $100 million investment through 2023.

**Exhibit 4-6. PREPA Operational Hydro Capacity Assumptions**

| Year | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|
| Capacity (MW) | 34 | 50 | 70 | 70 | 70 |
| Availability Factor | 20% | 40% | 60% | 80% | 90% |
| Capacity Factor | 15% | 25% | 28% | 28% | 28% |
| Annual Generation GWh | 44,676 | 109,500 | 171,696 | 171,696 | 171,696 |

Source: PREPA, Siemens.

#### 4.1.1.5 EcoEléctrica and AES PPOAs

To supplement its own capacity, PREPA purchases power from two co-generators under the terms and conditions of PPOAs, including 507 MW natural gas-fired combined cycle plant from EcoEléctrica, L.P. and 454 MW coal-fired steam electric cogeneration station from AES. The 961 MW of capacity provided by the two co-generators brings the total capacity available to PREPA to 5,011 MW[17].

In accordance with a 22-year PPOA that commenced in March 2000, each calendar year EcoEléctrica fixes the fuel cost per million BTU for the first 76 percent of the station's capacity for that year. For capacity in excess of 76 percent, PREPA has been charged a price based upon a spot[18] fuel price set by EcoEléctrica at the time the excess capacity was dispatched. The EcoEléctrica contract has a target availability factor of 93 percent, with associated capacity payments. Based on discussions with PREPA and advisors, a renewal of EcoEléctrica PPOA will be assumed in the base scenarios of the IRP; however, the plant is subject to economic retirement, if so decided by the least cost plan. A reduction on the fixed payments is assumed after 2022.

AES's coal-fired steam electric cogeneration station began commercial operation in November 2002. The owners of the facility have entered into a PPOA with the PREPA to provide 454 MW of power for a period of 25 years. Based on discussions with PREPA and its advisors, the base scenarios of the IRP will not assume a renewal of the AES PPOA, because this is a highly probable scenario due to the Puerto Rico Legislature consideration of stating a very strong public policy against the disposal of coal ash in local landfills.

The operational and cost parameters of the two PPOA plants are shown in Exhibit 4-7.

[17] This value corresponds to the sum of the maximum capacities considered in this study and includes the GTs and 34 MW of hydro units.

[18] This "spot price" is not directly related to the spot price of fuels in the market.

**Exhibit 4-7. EcoEléctrica and AES Operational Parameters**

| Parameters | Unit | EcoEléctrica CC | AES Coal Plant | |
|---|---|---|---|---|
| | | Unit 1 | Unit 1 | Unit 2 |
| Fuel | Type | Natural Gas | Coal | Coal |
| Maximum Capacity | MW | 507 | 227 | 227 |
| Minimum Capacity | MW | 275 | 166 | 166 |
| Fixed O&M Expense | 2018 $/kW-year | 162.05 | 77.96 | 77.96 |
| Variable O&M Expense | 2018 $/MWh | 0.00 | 7.09 | 7.09 |
| Capital Costs | 2018 $(000) | 124,226 | 121,499 | 121,499 |
| Heat Rate at Maximum Capacity | MMBtu/MWh | 7.50 | 9.79 | 9.79 |
| Heat Rate at Minimum Capacity | MMBtu/MWh | 8.31 | 9.93 | 9.93 |
| Forced Outage | % | 2 | 3 | 3 |
| Minimum Downtime | Hours | 8 | 48 | 48 |
| Minimum Runtime | Hours | 168 | 720 | 720 |
| Ramp Up Rate | MW/minute | 10 | 0 | 0 |
| Ramp Down Rate | MW/minute | 10 | 0 | 0 |

| Year | AES Coal Plant | | | EcoEléctrica CC | | |
|---|---|---|---|---|---|---|
| | Fixed O&M Costs (Nominal $/kW) | Variable O&M Costs (Nominal $/MWh) | Capital Costs (Nominal $000) | Fixed O&M Costs (Nominal $/kW) | Variable O&M Costs (Nominal $/MWh) | Capital Costs (Nominal $000) |
| 2018 | 77.96 | 7.09 | 121,499 | 162.05 | 0.00 | 124,226 |
| 2019 | 79.83 | 7.26 | 122,916 | 166.40 | 0.00 | 109,621 |
| 2020 | 81.75 | 7.43 | 122,991 | 170.84 | 0.00 | 120,962 |
| 2021 | 83.71 | 7.61 | 108,311 | 194.28 | 0.00 | 140,989 |
| 2022 | 85.72 | 7.79 | 94,026 | 198.95 | 0.00 | 143,808 |
| 2023 | 87.78 | 7.98 | 83,779 | 203.72 | 0.00 | 146,685 |
| 2024 | 89.88 | 8.17 | 74,127 | 208.61 | 0.00 | 149,618 |
| 2025 | 92.04 | 8.37 | 74,865 | 213.62 | 0.00 | 152,611 |
| 2026 | 94.25 | 8.57 | 75,627 | 218.75 | 0.00 | 155,663 |
| 2027 | 96.51 | 8.78 | 76,390 | 224.00 | 0.00 | 158,776 |
| 2028 | 98.83 | 8.99 | 77,159 | 229.37 | 0.00 | 161,952 |
| 2029 | 101.20 | 9.20 | 77,934 | 234.88 | 0.00 | 165,191 |
| 2030 | 103.63 | 9.42 | 78,714 | 240.51 | 0.00 | 168,495 |
| 2031 | 106.11 | 9.65 | 79,502 | 246.29 | 0.00 | 171,864 |
| 2032 | 108.66 | 9.88 | 80,298 | 252.20 | 0.00 | 175,302 |
| 2033 | 111.27 | 10.12 | 81,103 | 258.25 | 0.00 | 178,808 |
| 2034 | 113.94 | 10.36 | 81,915 | 264.45 | 0.00 | 182,384 |
| 2035 | 116.67 | 10.61 | 82,735 | 270.79 | 0.00 | 186,032 |
| 2036 | 119.47 | 10.86 | 83,564 | 277.29 | 0.00 | 189,752 |
| 2037 | 122.34 | 11.12 | 84,400 | 283.95 | 0.00 | 193,547 |
| 2038 | 122.34 | 11.12 | 84,400 | 283.95 | 0.00 | 193,547 |

Source: PREPA, Siemens.

### 4.1.2 Utility Scale Renewable PPOAs

This section includes a summary of the projects that were considered for modeling of the renewable generators. Between 2008 and 2012, PREPA signed 68 renewable PPOAs. As of December 2018, 58 PPOAs remained in effect with a total capacity of 1,480.6 MW, out of which 11 contracts are in operation.

#### 4.1.2.1 PPOAs in Commercial Operation or in Pre-Operation

As of December 2018, 11 PPOAs are in either commercial operation or in pre-operation (energized, under testing, and selling energy and renewable energy credits to PREPA). These projects represent 272.9 MW of capacity, including 147.1 MW of solar photovoltaic (PV), 121 MW of wind, and 4.8 MW of landfill gas.

Exhibit 4-8 shows the eight PPOAs in commercial operation as of December 2018, with a total capacity of 200.5 MW. Even though the installed capacity of Pattern Santa Isabel is 95 MW, the maximum capacity has been limited to 75 MW due to contractual limitation of compliance with the Minimum Technical Requirements (MTR). ). The plant capacity could increase to 95 MW during certain months (February to September), but it has not been allowed to reach these levels as the plant currently does not meet the MTR at those levels. The plant was modeled in this IRP at 75 MW, which will continue until Pattern can show that it meets the Minimum Technical Requirements with the increased output.

**Exhibit 4-8. Eight PPOAs under Commercial Operation**

| Ref. Number | Name | Status | Contract Number | Technology | Capacity MW |
|---|---|---|---|---|---|
| 1 | AES Ilumina | Operation | 2010-P00050 | Solar | 20 |
| 18 | Horizon Energy | Operation | 2011-P00034 | Solar | 10 |
| 46 | San Fermin Solar (Coqui Power) | Operation | 2011-P00050 | Solar | 20 |
| 60 | Windmar (Cantera Martino) | Operation | 2010-P00052 | Solar | 2.1 |
| 30 | Yarotek (Oriana) | Operation | 2011-P00048 | Solar | 45 |
| 32 | Go Green (Punta Lima) | Operation | 2010-AI0001 | Wind | 26 |
| 31 | Pattern (Pattern Santa Isabel) | Operation | 2010-P00047 | Wind | 75 |
| 24 | Fajardo Landfill Tech (Landfill Gas Technologies of Fajardo) | Operation | 2013-P00046 | Landfill G | 2.4 |
| | | **Total Capacity** | | | **200.5** |

Source: PREPA, Siemens.

The capacity factors for these PPOAs were derived from an assessment of the historical performance of them as shown in Exhibit 4-9. The Model Target is the forecasted capacity factor. Plant specific capacity factor estimates were derived considering the history and the fact that some years were partial operation or pre-operation.

**Exhibit 4-9. Historical Capacity Factors for Eight PPOAs in Commercial Operation**

| Ref Number | Name | | 2016 Hourly | 2015 5-minute | 2016 5-minute | 2017 5-minute | Model Target |
|---|---|---|---|---|---|---|---|
| 1 | AES Illumina | | 22% | 23% | 22% | 24% | **23%** |
| 18 | Horizon | | 27% | 19% | 27% | 29% | **24%** |
| 24 | Fajardo Landfill Tech (Landfill Gas Technologies of Fajardo) | | 52% | | | | **80%** |
| 30 | Yarotek (Oriana) | | | | 9% | 25% | **25%** |
| 46 | San Fermin (Coqui Power) | | 22% | | | | **22%** |
| 60 | Windmar (Cantera Martino) | | 23% | 25% | 23% | 26% | **24%** |
| | | **2013 Hourly** | **2014 Hourly** | **2015 Hourly** | **2016 Hourly** | **2017 Hourly** | |
| 31 | Pattern (Pattern Santa Isabel) | 18% | 25% | 27% | 22% | 25% | **23%** |
| 32 | Go Green (Punta Lima) | 25% | 24% | 26% | 22% | 24% | **24%** |

Exhibit 4-10 shows the PPOAs in pre-operation as of December 2018, with a total capacity of 52.4 MW. Humacao Solar Project, LLC is being developed in two phases: Phase 1 (20 MW) is in testing and Phase 2 (20 MW) is under construction as of December 20182018. A landfill gas project, Landfill Gas Technologies of Fajardo, LLC (Toa Baja Landfill), completed testing in July of 2017 and was in the process of achieving commercial operation when hurricanes Irma and María struck in September 2017. It is expected that the facility will be declared in commercial operation in 2019, so the plant is considered under commercial operation in the IRP. Exhibit 4-10 lists the PPOAs under pre-operation as of December 2018.

For the existing solar PPOAs and all future solar projects, the IRP has assumed a capacity factor of 22%. This value is viewed as conservative since the historical values are slightly higher, in the 23% range. For landfill gas, a capacity factor of 80% is assumed in this IRP.

**Exhibit 4-10. Three PPOAs under Pre-Operation**

| Ref. Number | Name | Status | Contract Number | Technology | Capacity MW |
|---|---|---|---|---|---|
| 7 | Fonroche Energy (Humacao Solar Project) | Pre-Operation | 2012-P00031 | Solar | 40.0 |
| 62 | Windmar (Vista Alegre/Coto Laurel) | Pre-Operation | 2012-P00052 | Solar | 10.0 |
| 25 | Toa Baja Landfill Tech (Landfill Gas Technologies of Fajai | Pre-Operation | 2013-P00073 | Landfill G | 2.4 |
| | | **Total Capacity** | | | **52.4** |

Source: PREPA, Siemens.

### 4.1.2.2 PPOAs in Renegotiation

Of the 18 PPOAs successfully renegotiated and amended in 2013-2014, 15 have not begun construction. Between 2015 and 2016, most of these companies requested extensions to start construction and commercial operation dates established in their PPOAs. Most of the requests were related to the difficulties alleged by the companies in securing financing for their projects due to the financial situation of the Government of Puerto Rico and PREPA. Exhibit 4-11 shows the list of the PPOAs under renegotiation. The PPOAs under re-negotiation are modeled as potential new supply options (volumes and sites), assuming benchmarked new solar prices instead of the PPOAs actual prices.

**Exhibit 4-11. Fifteen PPOAs under Renegotiation**

| Ref. Number | Name | Status | Contract Number | Technology | Capacity MW |
|---|---|---|---|---|---|
| 5 | Atenas Solar Farm (Desarrollos del Norte) | Re-negotiation | 2013-P00070 | Solar | 20 |
| 3 | Blue Beetle III | Re-negotiation | 2012-P00037 | Solar | 20 |
| 4 | Ciro Group (Ciro One Salinas) | Re-negotiation | 2011-P00043 | Solar | 57 |
| 15 | Grupotec USA Inc (Xzerta-Tec) | Re-negotiation | 2013-P00042 | Solar | 20 |
| 16 | Guayama Solar Farm (Guayama Solar Energy) | Re-negotiation | 2011-P00042 | Solar | 17.8 |
| 21 | Irradia Energy USA (Morovis Solar Farm) | Re-negotiation | 2012-P00053 | Solar | 33.5 |
| 42 | Moca Solar Farm | Re-negotiation | 2013-P00003 | Solar | 20 |
| 43 | North Coast Solar | Re-negotiation | 2013-P00041 | Solar | 20 |
| 36 | Renewable Energy Authority (Vega Serena) | Re-negotiation | 2012-P00045 | Solar | 20 |
| 39 | Resun (Barceloneta) | Re-negotiation | 2012-P00061 | Solar | 20 |
| 47 | Solaner | Re-negotiation | 2012-P00146 | Solar | 25 |
| 48 | Solar Blue (Solar Blue Bemoga) | Re-negotiation | 2013-P00052 | Solar | 20 |
| 57 | WindMar (Santa Rosa) | Re-negotiation | 2012-P00080 | Solar | 20 |
| 63 | YFN Yabucoa Solar (Justin Orozco) | Re-negotiation | 2013-P00049 | Solar | 20 |
| 6 | Energy Answers Arecibo | Re-negotiation | 2010-AI0018 | WTE | 79 |
| | | **Total Capacity** | | | **412.3** |

Source: PREPA, Siemens.

With respect of the Energy Answers Arecibo PPOA project, there are a number of permitting and local opposition challenges. Among others, the Governor of Puerto Rico retired the administration endorsement to the project. Hence, this project will not be considered as part of the IRP, which is conservative, as its location on the north of the transmission system and high contribution to the RPS would result in a favorable outcome from these two points of view. Other waste to energy technologies could be considered instead.

#### 4.1.2.3 PPOAs not Re-negotiated

There are 32 projects whose PPOAs were not renegotiated. For the IRP, these projects provide an indication of available sites and that be utilized by alternative renewable generation projects. Exhibit 4-12 lists the 32 PPOAs which were not renegotiated. These projects were considered in the IRP as potential new supply options (capacity and sites), assuming benchmarked new prices instead of the PPOAs actual prices.

**Exhibit 4-12.Thirty two PPOAs not Re-negotiated**

| Ref. Number | Name | Status | Contract Number | Technology | Capacity MW |
|---|---|---|---|---|---|
| 41 | Cabo Solar | Not Renegotiated | 2013-P00069 | Solar | 20 |
| 44 | Caracol Solar (Roma Solar) LLC | Not Renegotiated | 2013-P00004 | Solar | 20 |
| 52 | Carolina Solar (Trina) | Not Renegotiated | 2013-P00067 | Solar | 20 |
| 10 | Fonroche Energy (Humacao Solar Project) | Not Renegotiated | 2013-P00048 | Solar | 15 |
| 9 | Fonroche Energy (Solar Project Ponce) | Not Renegotiated | 2013-P00045 | Solar | 30 |
| 12 | Fonroche Energy ( Vega Baja Solar Project) | Not Renegotiated | 2013-P00050 | Solar | 15 |
| 8 | Fonroche Energy (Lajas Solar Project) | Not Renegotiated | 2013-P00046 | Solar | 10 |
| 11 | Fonroche Energy (South Solar 2) | Not Renegotiated | 2013-P00047 | Solar | 30 |
| 13 | GG Alternative Energy Corp. | Not Renegotiated | 2013-P00077 | Solar | 20 |
| 17 | Hatillo Solar (Pattern) | Not Renegotiated | 2013-P00074 | Solar | 30 |
| 19 | HSEA PR Isla Solar I | Not Renegotiated | 2013-P00057 | Solar | 40 |
| 22 | Jonas Solar Farm (Jonas Solar Energy) | Not Renegotiated | 2012-P000140 | Solar | 40 |
| 23 | Juncos Solar Energy | Not Renegotiated | 2012-P00138 | Solar | 20 |
| 26 | M Solar (M Solar Generating) | Not Renegotiated | 2012-P00142 | Solar | 50 |
| 34 | REA Ceiba (REA Energy Ceiba Solar Plant) | Not Renegotiated | 2013-P00076 | Solar | 20 |
| 33 | REA Energy (Luquillo Solar Plant) | Not Renegotiated | 2013-P00051 | Solar | 20 |
| 35 | REA Hatillo (REA Energy Hatillo Solar Plant) | Not Renegotiated | 2013-P00075 | Solar | 20 |
| 45 | Sierra Solar (Roma Solar) | Not Renegotiated | 2013-P00072 | Solar | 20 |
| 53 | Vega Baja Solar Energy | Not Renegotiated | 2012-P00139 | Solar | 30 |
| 54 | Western Wind (Yabucoa Solar) | Not Renegotiated | 2011-P00090 | Solar | 30 |
| 56 | WindMar (Dorado-Toa Baja) | Not Renegotiated | 2012-P00079 | Solar | 20 |
| 2 | Aspenall Energy | Not Renegotiated | 2012-P00089 | Wind | 10 |
| 14 | GG Alternative Energy Corp. | Not Renegotiated | 2013-P00071 | Wind | 10 |
| 50 | Tradewind Energy (Tradewinds Energy Barceloneta) | Not Renegotiated | 2012-P00030 | Wind | 75 |
| 51 | Tradewind Energy (Tradewinds Energy Vega Baja) | Not Renegotiated | 2012-P00028 | Wind | 50 |
| 55 | Wind to Energy | Not Renegotiated | 2011-P00101 | Wind | 20 |
| 58 | WindMar (Dorado-Toa Baja) | Not Renegotiated | 2012-P00095 | Wind | 44 |
| 61 | Windmar (Punta Ventana) | Not Renegotiated | 2008-AI0066C | Wind | 18.4 |
| 59 | Windmar (Punta Verraco) | Not Renegotiated | 2012-P00049 | Wind | 34.5 |
| 49 | Sunbeam | Not Renegotiated | 2010-AI0031 | WTE | 10 |
| 37 | Renewable Power Group | Not Renegotiated | 2012-P00010 | Landfill G | 2 |
| 38 | Renewable Power Group | Not Renegotiated | 2012-P0009 | Landfill G | 1.5 |
| | | **Total Capacity** | | | **795.4** |

Source: PREPA, Siemens.

### 4.1.2.4 PPOAs Assumed Contract Pricing

As indicated earlier, any project that is not in operation or pre-operation (i.e. all other projects irrespective of having re-negotiated PPOAs or not), was modeled in the IRP as potential new supply sites with commercial conditions according to Siemens forecast for new solar prices.

For the projects in operation or pre-operation, Siemens assumed the price conditions shown in Exhibit 4-13, where the Contract Price is inclusive of RECs and does not have escalation clauses.

**Exhibit 4-13. Projects in Operation or Pre-operation Prices**

| Project Type | Contract Price $/MWh |
|---|---|
| Solar PV | 150 |
| Wind | 125 |
| Land fill gas | 100 |

Note: above prices include RECs and does not have escalation clauses.

## 4.2 Environmental Considerations

Environmental regulations have the potential to impact the overall cost and operation of electric generation. As such, compliance requirements for key environmental regulations with the potential to significantly impact portfolio costs and resource decisions need to be factored into this IRP analysis. This initial review considered existing regulations and the outlook for potential new compliance requirements over the study horizon (2019-2038). An overview of these key regulations, applicability to PREPA's existing and future portfolio and the approach to incorporate compliance into the IRP analysis are documented in this section. Although there are numerous environmental policies impacting the energy sector at the federal, state and local levels, the primary policies that are driving power markets and generation decisions are the suite of Environmental Protection Agency (EPA) rules addressing power plant emissions and state driven renewable and alternative energy portfolio standards. The environmental regulations determined by Siemens and PREPA to be potentially significant and factored into the IRP analysis include federal air regulations, water regulations, and local policy dictating targets for renewable and alternative energy, specifically:

- National Ambient Air Quality Standards (NAAQS)
- Mercury and Air Toxics Standards (MATS)
- Carbon Regulation
    - Greenhouse Gas (GHG) Emission Standards for New, Modified, and Existing Electric Generating Units
    - Outlook for potential future regulation of GHG emissions from power generators
- Puerto Rico Renewable Portfolio Standard (RPS)
- Section 316(b) of the Clean Water Act
- Puerto Rico Water Quality Standards Regulation

A summary of PREPA's generating units and applicability to the air quality regulations is presented in Exhibit 4-14.

**Exhibit 4-14: Summary of PREPA Units[19] and Emissions Regulatory Coverage**

| | Generation Units | Capacity (MW) | Fuel | SO2 EPA Final Designation | MATS Affected | Carbon Emissions |
|---|---|---|---|---|---|---|
| MATS Affected Units | Aguirre 1 ST | 450 | No. 6 fuel oil | Nonattainment | Yes | Yes |
| | Aguirre 2 ST | 450 | No. 6 fuel oil | Nonattainment | Yes | Yes |
| | Costa Sur 3 ST* | 85 | No. 6 fuel oil | Attainment/Unclassifiable | Yes | Yes |
| | Costa Sur 4 ST* | 85 | No. 6 fuel oil | Attainment/Unclassifiable | Yes | Yes |
| | Costa Sur 5 ST | 410 | Natural gas, No. 6 fuel oil capable | Attainment/Unclassifiable | Yes | Yes |
| | Costa Sur 6 ST | 410 | Natural gas, No. 6 fuel oil capable | Attainment/Unclassifiable | Yes | Yes |
| | Palo Seco 1 ST* | 85 | No. 6 fuel oil | Nonattainment | Yes | Yes |
| | Palo Seco 2 ST* | 85 | No. 6 fuel oil | Nonattainment | Yes | Yes |
| | Palo Seco 3 ST | 216 | No. 6 fuel oil | Nonattainment | Yes | Yes |
| | Palo Seco 4 ST | 216 | No. 6 fuel oil | Nonattainment | Yes | Yes |
| | San Juan 7 ST | 100 | No. 6 fuel oil | Nonattainment | Yes | Yes |
| | San Juan 8 ST | 100 | No. 6 fuel oil | Nonattainment | Yes | Yes |
| | San Juan 9 ST* | 100 | No. 6 fuel oil | Nonattainment | Yes | Yes |
| | San Juan10 ST* | 100 | No. 6 fuel oil | Nonattainment | Yes | Yes |
| Combined Cycle | Aguirre 1 CC | 260 | Diesel | Nonattainment | No | Yes |
| | Aguirre 2 CC | 260 | Diesel | Nonattainment | No | Yes |
| | San Juan 5 CC | 200 | Diesel | Nonattainment | No | Yes |
| | San Juan 6 CC | 200 | Diesel | Nonattainment | No | Yes |
| Gas Turbine | Cambalache 2 GT | 83 | Diesel | Attainment/Unclassifiable | No | Yes |
| | Cambalache 3 GT | 83 | Diesel | Attainment/Unclassifiable | No | Yes |
| | Mayagüez 1 GT | 50 | Diesel | Attainment/Unclassifiable | No | Yes |
| | Mayagüez 2 GT | 50 | Diesel | Attainment/Unclassifiable | No | Yes |
| | Mayagüez 3 GT | 50 | Diesel | Attainment/Unclassifiable | No | Yes |
| | Mayagüez 4 GT | 50 | Diesel | Attainment/Unclassifiable | No | Yes |
| | Daguao 2 GTs | 42 | Diesel | Attainment/Unclassifiable | No | Yes |
| | Palo Seco GT11, 12 | 42 | Diesel | Nonattainment | No | Yes |
| | Palo Seco GT21, 22 | 42 | Diesel | Nonattainment | No | Yes |
| | Palo Seco GT31, 32 | 42 | Diesel | Nonattainment | No | Yes |
| | Aguirre GT21 & 22 | 42 | Diesel | Nonattainment | No | Yes |
| | Costa Sur GT11, 12 | 42 | Diesel | Attainment/Unclassifiable | No | Yes |
| | Jobos GT11, 12 | 42 | Diesel | Attainment/Unclassifiable | No | Yes |
| | Yabucoa GT11, 12 | 42 | Diesel | Attainment/Unclassifiable | No | Yes |
| | Vega Baja GT11, 12 | 42 | Diesel | Attainment/Unclassifiable | No | Yes |
| Hydro | Hydro (various) | 34 | Water | NA | No | No |
| IPP units | AES Coal Plant | 454 | Coal | Attainment/Unclassifiable | Yes** | Yes |
| | EcoEléctrica Plant | 507 | Natural Gas | NA | No | Yes |

* Costa Sur 3 and 4 ST, Palo Seco 1 and 2 ST, and San Juan 9 and 10 ST listed here will not be included in the IRP analysis as future generating resources.
**MATS affected unit, however, PREPA is not responsible for compliance with MATS
Source: EPA, PREPA, Siemens

### 4.2.1 National Ambient Air Quality Standards (NAAQS)

The U.S. EPA sets standards for six criteria pollutants[20] under the Clean Air Act (CAA) and is required to regularly review and update these standards as necessary. Particulate matter, nitrogen

[19] Cambalache 1 GT, an 83MW diesel fired gas turbine, is currently out of service and is not assumed to be operational in the future in the IRP.
[20] The six criteria pollutants are ozone, particulate matter, carbon monoxide, nitrogen oxides, sulfur dioxide, and lead.

oxides and sulfur dioxide (SO2) are criteria pollutants emitted from fossil fuel combustion. Ozone levels can indirectly be impacted by fossil fuel emissions. No recent changes have been made to NAAQS for particulate matter and nitrogen oxides. Although the potential for these standards to change exists over the study horizon, no specific assumptions around these potential changes were made in modeling, given the uncertainty and overall expectation that the portfolio will become less fossil fuel based in the coming years.

### 4.2.2 SO2 NAAQS

In January of 2018, EPA updated attainment designations for SO2 for areas in Puerto Rico based on air quality modeling. The 1-hour SO2 standard of 75 parts per billion was finalized in June 2010; however, the latest round of designations was published in January 2018 and became effective in April 2018. Several areas in Puerto Rico were designated as non-attainment areas, meaning that they were found not to meet the SO2 standard. Other areas in Puerto Rico were designated as being in attainment or otherwise not able to be classified at this time. The designations are based on emissions from all sources of SO2 emissions including transportation and industrial fuel use. For the IRP, the environmental review is focused on emissions from electric generating units. The combustion of coal- and petroleum-based fuels releases SO2 emissions. Area designations for Puerto Rico are shown in the exhibits below.

**Exhibit 4-15: Puerto Rico San Juan Area $SO_2$ Designations**


Source: EPA

**Exhibit 4-16: Puerto Rico Guayama Salinas Area $SO_2$ Designations**


Source: EPA

In the San Juan area, the San Juan and Palo Seco generating facilities represent significant SO2 emitting sources in the area. Actual historic emissions reported by PREPA are presented in Exhibit 4 17. Several industrial facilities emitting SO2 are located in the San Juan area, all of which are reported by the EPA to emit less than 35 tons SO2 annually. The San Juan Luis Munoz Marin Airport is also located in the San Juan area and is designated as a moderate source with annual emissions reported at 586 tons SO2 in 2014. Another potentially large source of emissions in the area are the port and mobile sources such as is ship and vehicle traffic. In the Guayama Salinas area, the Aguirre generating facility is the most significant source contributor in the area. No other specific point sources were included in the Guayama Salinas area modeling analysis performed by the EPA in developing these designations. Aguirre historical emissions are also included in Exhibit 4 17.

**Exhibit 4-17: Actual Reported $SO_2$ Emissions for PREPA Units in Nonattainment Areas (tons $SO_2$)[21]**

| Facility | Area | 2013 Emissions | 2014 Emissions | 2015 Emissions |
|---|---|---|---|---|
| San Juan | San Juan | 5,307 | 5,135 | 6,063 |
| Palo Seco | San Juan | 5,700 | 3,128 | 2,979 |
| Aguirre | Guayama Salinas | 9,640 | 9,261 | 9,585 |

Source: PREPA, EPA Technical Support Document Chapter 36, Final Round 3 Area Designations for the 2010 1-hour $SO_2$ Primary National Ambient Air Quality Standard for Puerto Rico

Units emitting SO2 located in areas designated as attainment or unclassifiable will still continue to monitor and report emissions to the EPA, but do not otherwise have to alter operations at this time.

Units emitting SO2 located in areas designated as nonattainment are required to be included in an SO2 State Implementation Plan (SIP) that must be submitted to the EPA by Puerto Rico and finalized by October 2019. The Puerto Rico Environmental Quality Board (EQB) will develop the SIP, which will lay out a plan for how the nonattainment areas will achieve compliance with the SO2 standard by 2023. Options for compliance for generating units include installation of sulfur emission control technology, fuel switching, or ceasing or reducing operations. Nonattainment designated areas are also subject to Nonattainment New Source Review requirements for permitting new and modified SO2 emitting facilities in these areas.

PREPA units in locations classified as nonattainment for SO2 are presented in the Exhibit below:

[21] Note that none of the PREPA units are equipped with continuous emission monitoring (CEMS). Emissions are estimated based on fuel specifications and hours of unit operation as reported by PREPA to the Puerto Rico EQB.

**Exhibit 4-18: PREPA Units Included in Nonattainment $SO_2$ Standards Designation Areas**

| Area | Generation Units | Capacity (MW) | Fuel | SO2 EPA Final Designation |
|---|---|---|---|---|
| Guayama Salinas | Aguirre 1 ST | 450 | No. 6 fuel oil | Nonattainment |
| | Aguirre 2 ST | 450 | No. 6 fuel oil | Nonattainment |
| | Aguirre 1 CC | 260 | Diesel | Nonattainment |
| | Aguirre 2 CC | 260 | Diesel | Nonattainment |
| | Aguirre GT21 & 22 | 42 | Diesel | Nonattainment |
| San Juan | Palo Seco 1 ST | 85 | No. 6 fuel oil | Nonattainment |
| | Palo Seco 2 ST | 85 | No. 6 fuel oil | Nonattainment |
| | Palo Seco 3 ST | 216 | No. 6 fuel oil | Nonattainment |
| | Palo Seco 4 ST | 216 | No. 6 fuel oil | Nonattainment |
| | Palo Seco GT11 & GT12 | 42 | Diesel | Nonattainment |
| | Palo Seco GT21 & GT 22 | 42 | Diesel | Nonattainment |
| | Palo Seco GT31 & GT32 | 42 | Diesel | Nonattainment |
| | San Juan 5 CC | 200 | Diesel | Nonattainment |
| | San Juan 6 CC | 200 | Diesel | Nonattainment |
| | San Juan 7 ST | 100 | No. 6 fuel oil | Nonattainment |
| | San Juan 8 ST | 100 | No. 6 fuel oil | Nonattainment |
| | San Juan 9 ST | 100 | No. 6 fuel oil | Nonattainment |
| | San Juan 10 ST | 100 | No. 6 fuel oil | Nonattainment |

Source: EPA, PREPA

Details on the Puerto Rico SIP will be updated by the results of the IRP analysis. The IRP will track $SO_2$ emissions from each portfolio and offer options for fuel switching (i.e. should natural gas become available in the north) and operational changes (i.e. minimum run or retirement and replacement with lower emitting generation options) to existing units. Facility-level operation and emissions resulting from the preferred portfolios will be provided to the Puerto Rico EQB. At this time, the following assumptions in the IRP analysis are expected to support emission reductions from these facilities:

- Palo Seco steam units 1 and 2 will not be assumed as future generating resources in the IRP analysis.
- San Juan steam units 9 and 10 will not be assumed as future generating resources in the IRP analysis.

### 4.2.3 Mercury and Air Toxics Standards (MATS)

The EPA regulates emissions of hazardous pollutants from electric generating units. EPA's Mercury and Air Toxics Standards (MATS), originally issued in February 2012, imposes emission reductions of mercury, acid gases, and particulate matter, and also requires subject facilities to comply with work practice standards. This is a technology-forcing regulation with no allowance trading. The rule came into effect in April of 2015 and existing plants can apply for a one year extension to reach compliance. PREPA applied for and received a one-year compliance extension for Aguirre. The

MATS rule sets a decision point for generators – control or retires – even if cost drivers may come after 2016.

Several groups filed lawsuits challenging various aspects of the MATS rule, including the EPA's determination that it was appropriate and necessary to regulate emissions from power plants. On June 29, 2015, the Supreme Court of the United States found it unreasonable that the EPA did not consider costs in its initial finding that it was appropriate and necessary to regulate these emissions,[22] and the case was remanded to the D.C. Circuit Court of Appeals for further review. The D.C. Circuit remanded the proceeding to EPA to make a finding on the costs issue without vacating the MATS rule, and the MATS rule remains in effect. In April 2016, EPA published a final supplemental finding that it is appropriate and necessary to regulate hazardous air pollution from coal and oil fired steam EGUs, finding that the consideration of costs does not alter its initial finding that these emissions are necessary to regulate.[23] Therefore, steam coal- and oil-fired power plants continue to be legally obligated to meet the MATS standards.

PREPA units subject to MATS are presented in the exhibit below and the approach taken by each unit to comply with MATS.

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[22] *Michigan et al. v. Environmental Protection Agency et al.*, 135 S.Ct. 2699 (2015).

[23] On December 27, 2018, EPA proposed to revise the April 2016 supplemental cost finding for MATS in order to correct what EPA deems to be flaws in the analysis. EPA proposes to determine that it is not "appropriate and necessary" to regulate hazardous air pollutant emissions from power plants under Section 112 of the CAA. EPA's proposal also states that the emission standards and other requirements of the MATS rule would remain in place, since EPA is not proposing to remove coal- and oil-fired power plants from the list of sources that are regulated under Section 112 of the Act at this time. However, EPA requests comment on whether the EPA has the authority or obligation to delist the source category and rescind the standards, or to rescind the standards without delisting.

**Exhibit 4-19: PREPA Existing Units Subject to MATS**

| | Generation Units | Fuel | MATS Compliance Status |
|---|---|---|---|
| MATS Affected Units (PREPA Responsible for Compliance) | Aguirre 1 ST | No. 6 fuel oil | No quarterly test performed until Q4 2018(1) |
| | Aguirre 2 ST | No. 6 fuel oil | No quarterly test performed until Q4 2018(1) |
| | Costa Sur 3 ST | No. 6 fuel oil | This unit is currently not operating and will not be considered as a future generating resource in the IRP |
| | Costa Sur 4 ST | No. 6 fuel oil | This unit is currently not operating and will not be considered as a future generating resource in the IRP |
| | Costa Sur 5 ST | Natural gas(No. 6 fuel oil capable) | MATS compliant – now operating on natural gas |
| | Costa Sur 6 ST | Natural gas(No. 6 fuel oil capable) | MATS compliant – now operating on natural gas |
| | Palo Seco 1 ST | No. 6 fuel oil | Designated as limited-use unit, but has exceeded heat-input threshold for limited use. This unit is currently not operating and will not be considered as a future generating resource in the IRP |
| | Palo Seco 2 ST | No. 6 fuel oil | Designated as limited-use unit, but has previously exceeded heat-input threshold for limited use. This unit is currently not operating and will not be considered as a future generating resource in the IRP |
| | Palo Seco 3 ST | No. 6 fuel oil | PM emissions above MATS limit(2) |
| | Palo Seco 4 ST | No. 6 fuel oil | This unit is currently not operating(2) |
| | San Juan 7 ST | No. 6 fuel oil | Designated as limited-use unit, but has exceeded heat-input threshold for limited use units. Modeled as running for reliability considerations in place of San Juan 9 (2) |
| | San Juan 8 ST | No. 6 fuel oil | Designated as limited-use unit, but has exceeded heat-input threshold for limited use units. Modeled as running for reliability considerations in place of San Juan 10 (2) |
| | San Juan 9 ST | No. 6 fuel oil | PM emissions above MATS limit. Will not be considered as a future generating resource in the IRP |
| | San Juan 10 ST | No. 6 fuel oil | This unit is currently not operating. Will not be considered as a future generating resource in the IRP |
| MATS Affected Units (PREPA not Accountable for Compliance) | AES Coal Plant | Coal | Power Purchase - PREPA is not responsible for MATS compliance, AES represents that the plant is MATS compliant |

(1) Aguirre 1 & 2 are the largest single units in the system and are required to meet the load. Aguirre 1 & 2 can be made MATS compliant by their conversion to natural gas or can be retired (or designated limited use), when new generation is installed in the system.

(2) These units in the north of the island are required to manage transmission limitations and can be retired (or designated limited use) when new generation is commissioned in the north.

Source: EPA, PREPA

The IRP analysis includes the following for MATS affected units:

- Aguirre units 1 and 2 are currently operating and are not MATS compliant. At this time, these units are required for reliability. Future resource portfolios will assume that these units only operate as needed for reliability purposes and then cease their operations as a means to comply with MATS. Conversion to natural gas was included as an option in Scenario 5. These units continue to operate under a 1999 consent decree with EPA. Additional action may be required pending the EPA's review of the results of the IRP. The IRP assumes that the units could run until 2025, when new large combined cycle plants could be in service.

- Costa Sur units 5 and 6 are complying with MATS by fuel switching, operating on natural gas. As of May 2018, these units began operating on natural gas. However, the permit still allows the units to operate on no. 6 fuel oil.
- Costa Sur steam units 3 and 4 and Palo Seco steam units 1 and 2 are not currently in operation and will not be considered as future generating resources in the IRP.
- Palo Seco Unit 4 and San Juan Unit 10 are currently not in operation. Palo Seco unit 3 and San Juan unit 9 have had PM emissions above the MATS limit and are run for reliability needs. San Juan Units 7-8 are designated as limited use units, which do not have to meet the MATS emission limits, but must comply with certain work practice standards. San Juan Units 7-8 have previously exceeded the heat input limit for limited-use units, which require them to operate at less than eight percent capacity factor, averaged over 24-month block periods. San Juan units 9 and 10 will not be considered as a future resource in the IRP. The IRP assumes that the units could run until 2025, when new large combined cycle plants could be in service.
- New generating units included in the portfolio analysis are assumed to be MATS compliant.

Limited use and retirement options are also included in assessing portfolio options. PREPA will not consider investing in costly emission controls as a compliance option and therefore this was not considered in this analysis.

Other operational adjustments to comply with MATS have been considered, but have been deemed through detailed conceptual analysis not to be viable compliance strategies for PREPA's units. Fuel blending was one compliance strategy assessed, as well as operational adjustments including infrequent soot blowing, higher burn point temperatures, and excess oxygen adjustments. Combinations of these operational adjustments have, albeit with significant challenges, enabled Hawaiian Electric Company (HECO) to comply with MATS. Characteristics of PREPA's units relative to HECO's units render them unsuitable to comply through these operational adjustments, including their larger size, lower burn temperatures, presence of continuous emission monitoring systems, mandated frequent soot blowing and higher average load levels. HECO also found fuel blending not to be a viable compliance strategy for its units. MATS compliance through fuel blending with ultralow sulfur diesel was considered by PREPA, but was determined not to be a viable compliance option for MATS affected units in Puerto Rico based on PREPA's and its advisors' independent evaluations. In addition, based on information provided by PREPA and its advisors, MATS compliance through operational modifications is not an option for the steam units.[24]

### 4.2.4 Carbon Regulation

No economy-wide national regulation of carbon emissions exists in the in the U.S. at this time. In December 2009, EPA finalized its endangerment finding for GHG emissions from mobile sources, officially giving it the authority to regulate these emissions under the Clean Air (CAA). Beginning January 1, 2010, major stationary sources were required to track and report their annual GHG

[24] Memorandum, "Staff Opinion – Assessment of Fuel Blending for MATS Compliance", Puerto Rico Electric Authority, July 25, 2018

emissions to EPA. The EPA has issued regulations regulating the GHG emissions of new, modified, and existing electric generating units. An overview of these regulations, current status and applicability to this IRP are presented below.

### 4.2.5 New Source Performance Standards for GHGs for Electric Generating Units

In October 2015, EPA finalized New Source Performance Standards (NSPS) for Electric Utility Generating Units under §111(b) of the CAA, a proposed regulation that would establish carbon dioxide (CO2) emission limits for certain new, modified, and reconstructed power plants in the U.S. The NSPS applies to new, reconstructed, or modified steam EGUs and to new or reconstructed natural gas combustion turbines. The NSPS sets a rate limit of 1,000lbs of CO2/MWh for combined cycle natural gas plants and a limit of 1,400lbs of CO2/MWh for coal plants. The NSPS effectively prevents the permitting of new coal-fired power plants that are not equipped with CO2 pollution control equipment such as carbon capture and sequestration (CCS), a technology that has yet to be deployed on a commercial scale.

In December 2018, EPA issued a proposed rule to amend the Section 111(b) standards for GHGs. The main feature of this proposal is that it would change the best system of emission reduction (“BSER”) and emissions standards for steam EGUs. EPA did not propose changes to the NSPS for newly constructed or reconstructed natural gas stationary combustion turbines, as a part of the proposal.

Even if the rule is not amended, it is not anticipated to have a significant impact in PREPA’s future generation portfolio. No new coal is expected. Even in the absence of this rule, Pace Global does not expect any build out of additional coal capacity in the near future. Other natural gas and fossil fuel fired units would be expected to need to meet these new source standards.

### 4.2.6 Clean Power Plan and Affordable Clean Energy Rule – GHG Emissions Guidelines for Existing Electric Generating Units

In October 2015, EPA finalized the Clean Power Plan (CPP), which established emissions guidelines for certain existing electric generating units under §111(d) of the CAA. The CPP established state by state emission targets for affected existing generation units. Under the CPP, states would determine the approach to meet their emissions goal, including choosing to comply as a rate goal (lb $CO_2$/MWh) or a mass goal (short tons of $CO_2$). Overall, the aggregate state goals (on a mass basis) would reduce emissions from affected sources by an estimated 32% below 2005 levels by 2030. The initial compliance period would have begun in 2022, with the final reduction goal to be achieved by 2030. Trading of emissions between states would be encouraged under the CPP. It should be noted that Puerto Rico was not covered under the final CPP. Draft standards for existing generators located on Indian Country and in the U.S. Territories, including Puerto Rico, were released in 2014, but were never finalized. The final CPP noted that additional data would be needed to define final standards for these areas.

In February of 2016, the Supreme Court granted a request to stay the CPP while the courts rule on the legal challenges to the rule, rendering the rule and all associated planning deadlines not in effect until further notice. Further, the Trump Administration directed the EPA to perform a detailed review of the rule in a March 2017 Executive Order. This review resulted in a proposal to withdrawal the CPP in its entirety. Moreover, on August 31, 2018, EPA published the Notice of Proposed Rulemaking for the rule to replace the CPP—the “Affordable Clean Energy” or “ACE” rule. The

Proposed ACE rule to replace the Clean Power Plan also currently proposes that emissions guidelines would not apply to Puerto Rico. However, until the final proposal is issued, the regulatory status remains uncertain.

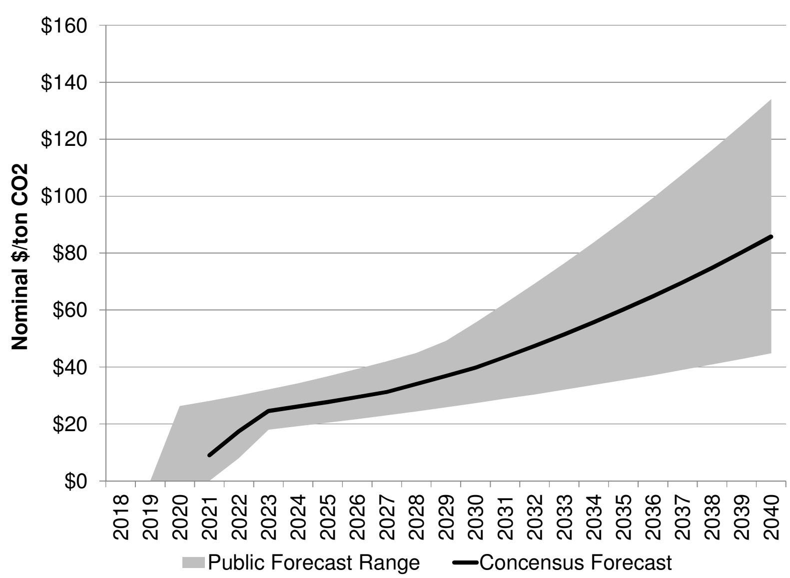
Given the pending proposals to withdraw and replace the CPP, a great deal of uncertainty exists at this time over the future of regulations covering $CO_2$ emissions from existing power generators. Because Puerto Rico was not regulated under the final CPP and the prevailing expectation is that the CPP rule will be withdrawn in its entirety, the CPP does not impact this IRP. Sensitivity analysis considered for this IRP would assess the impacts of a policy placing a price on carbon in the IRP.

### 4.2.7 Consideration of the Effect of Future Regulation of Carbon on Generators in Puerto Rico

Despite the absence of the CPP or any other national regulation of carbon emissions from power generators at this time, the potential for enactment of such regulation over the study horizon remains. To account for this uncertainty in the IRP analysis, sensitivities could be considered in supplemental analysis to include a price on $CO_2$ emissions from fossil generators.

This price on carbon is not intended to represent a specific view on an expected future national carbon program. The structure, timing, and resulting requirements of a potential future program are not known at this time. Rather this price could represent a future carbon trading or carbon tax policy, and is intended to analyze the implications that a price on carbon would have on PREPA's portfolio operation and resource decisions. The carbon price considered for the potential sensitivity analysis is based on variety of publicly available sources and is presented in the exhibit below along with the range of pricing represented in public sources referenced.

**Exhibit 4-20: Carbon Price – Carbon Regulation Sensitivities**




Source: U.S. Energy Information Administration, Synapse, IHS, Siemens

### 4.2.8 Puerto Rico RPS

Renewable Portfolio Standards (RPS) are regulated programs placing an obligation on electricity suppliers that a certain percentage of their electricity sold be derived from alternative or renewable energy resources. At this time, 29 states, Puerto Rico, and the District of Columbia have enacted mandatory state-level RPS requirements. These RPS rules dictate expansion options and economics.

Puerto Rico established by Act 82-2010 an RPS in July of 2010 which set minimum targets of renewable and alternative energy. This rule requires that load serving entities to supply increasing shares of retail sales with qualified renewable and alternative source. This can be procured by direct purchase of the energy including renewable attributes or by the purchase of renewable energy certificates (RECs), which are tradable instruments representing the renewable attributes qualified generation, unbundled from the energy itself. RECs allow for compliance flexibility and can be banked for use up to two years forward. The RPS targets set forth by the legislation are below. PREPA may set interim goals to meet these prescribed levels. Current law establishes compliance as a percent of purchased REC's of qualifying renewable generation vs total sales, subject to certain grounds for permissible non-compliance.

- 12 percent – 2015 through 2019
- 15 percent – 2020 through 2027
- 20 percent – 2035 and beyond

Eligible renewable generation technologies include wind, solar, geothermal, renewable biomass or biofuel, new hydropower. Alternative renewable energy generation technologies that can also be used to meet the requirement include landfill gas, fuel cells, and municipal solid waste. The rules around the use of net metered renewable energy for RPS compliance are unclear. To date, PREPA is not permitted to use RECs from distributed solar installations for RPS compliance. To be conservative in the IRP, it will be assumed that behind the meter renewables will not count towards RPS requirements, unless advised from PREPA otherwise.

The RPS to date has not been met. RECs that PREPA does purchase under renewable purchase agreements generally range from $2 to $4/MWh and include wind and solar photovoltaic generating facilities.

The LTCE had as an input compliance with the current RPS and we also assess the ease or difficulty that the various plans would have to reach 50% penetration.

### 4.2.9 Clean Water Act Section 316(b)

The EPA issued the final standards for cooling water intake structures under Section 316(b) of the Clean Water Act in May 2014. This rule aims to reduce the impingement and entrainment of marine life from the impacts of water intake structures. This rule applies to industrial facilities, including electric generation facilities, that intake water for operation from bodies of water (i.e. lakes, rivers, estuaries, and oceans) exceeding two million gallons per day and of which 25 percent is used exclusively for cooling purposes. Covered facilities are required to obtain a National Pollutant Discharge Elimination System (NPDES) permit. Further requirements are based on water withdrawal levels.

- 2 million gallon per day – action to reduce the adverse impact to marine life including control technologies like velocity screens and implement biological impact monitoring at the intake structures
- 125 million gallon per day – additional assessments of impacts required to assess permit requirements
- New systems – review on facility will be conducted to assess controls needed, this applies to new facilities and expansions at existing facilities that would significantly increase water intake volumes

Noting the unique design of individual facilities, the rule is not prescriptive of controls required, rather assigns the permitting agencies the ultimate discretion in individual facility requirements.

All PREPA generating facilities operate under site-level NPDES permits. Through these permits, information requested to assess facility control needs to comply with 316(b) are being considered. Any new or facility expansions that impact water intake will be designed to comply with requirements under 316(b).

### 4.2.10 Puerto Rico Water Quality Standards Regulation

Section 304(a) of the CWA requires the EPA to publish water quality criteria based on the latest scientific review. These criteria can then be used by states to adopt or build on to define state specific water quality standards as a requirement of the CWA under Section 303(c).

The Puerto Rico EQB publishes and maintains Water Quality Standards Regulation to protect preserve, maintain and enhance the quality of water in Puerto Rico compatible with the social and economic needs of the Commonwealth. The latest standards were updated in April 2016. Specifically, this regulation designates uses for bodies of water, define water quality standards, identify rules and standards applicable to sources of pollution, and establish other measures deemed necessary to maintain water quality.

All existing generation facilities that have intake cooling water, discharge, or otherwise trigger requirements under the Water Quality Standards Regulation operate under NPDES permits. These permits document facility specific requirements and tolerances based on the applicable regulation and further informed by stakeholder input. Permitting for new facilities is outside of the scope of the IRP. However, new generation options considered as a part of the IRP analysis will assume reasonable levels of controls that would expected to comply with applicable water quality requirements for new sources in Puerto Rico.

Part
5

# Resource Needs Assessment

## 5.1 Overview of the Needs

Resource planning is a multifaceted and technically complex process for most utilities. However, Puerto Rico and PREPA have a particularly complex resource planning environment due to numerous factors, including the isolated island operation without electrical or fuel delivery connections to other locations, the significant age and poor condition of much of the existing generation fleet, the uncertainty of the future economic conditions which greatly impact the electric generation requirements, and the vulnerability of the territory to catastrophic weather events. While many utilities are looking for ways to make incremental changes to their system to enhance their resiliency, the devastation to PREPA's electrical infrastructure from the 2017 Hurricanes forced PREPA to rethink its entire system design including resource planning. This IRP, following on the heels of one of the worst storm related outages experienced by an electric utility, offers PREPA an opportunity to define a sharp and significant improvement in direction for the future energy supply of Puerto Rico.

Further to the above, 2019 IRP is not a classical IRP designed to identify the least cost approach to address the expected gap between load and resources and maintaining a desired Planning Reserve Margin (PRM), but rather produce a plan that satisfies the objectives of being customer centric, financial viability, reliability and resiliency and economic growth, on a context of significant declines in the load.

Thus, this IRP is designed instead, to address the following resource needs:

a) Address the impacts of an aging generation infrastructure that burns costly liquid fuels (mostly heavy fuel oil), which has poor reliability, does not meet environmental regulations (e.g. MATS) and is inflexible, which limits the incorporation of renewable resources.

b) Achieve a reduction of cost of supply by the incorporation of renewable resources and take advantage of the currently observed and forecasted reduction in cost.

c) Achieve compliance with RPS mandate. However, Siemens observed that economies alone justified greater levels of penetration.

d) Shift from centralized generation located in the south of the island to a more decentralized generation mix, with resources across the island.

Taking in consideration the above, through input received during a series of Stakeholder Workshops, discussion with PREPA staff and Siemens own knowledge and experience with resource planning, the PREPA and Siemens project team defined a number of aspects that the resource planning resulting from this IRP must address. These needs included but were not limited to:

- Reduce the dependence on an aging, inflexible and not reliable fleet and move away from the reliance on large, concentrated generating plants.
- Improve the overall resiliency of the system to better enable Puerto Rico to withstand and recover from future severe weather and other disruptive events.
- Improve the sustainability of the electrical end use and supply.
- Determine the role of natural gas in PREPA future resource supply.
- Include in the analysis, the uncertainty associated with load, fuel costs and costs of supply technologies.
- Create a resource plan that addresses the needed changes while balancing the cost of service to customers.
- Deliver a transparent planning process that allows stakeholders to review and understand the planning process and recommendations.

In the balance of this section Siemens present the strategies, scenarios and sensitivities used to formulate the multiple long term capacity expansion plans to address the needs above.

## 5.2 Three Strategies

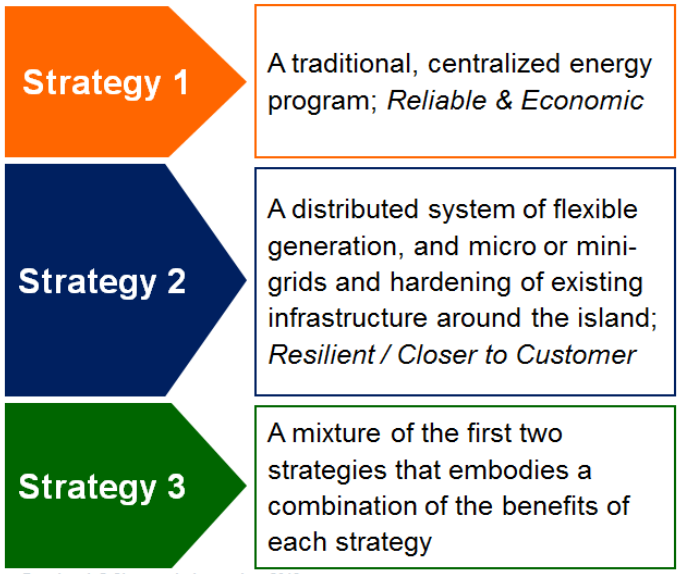
As part of the stakeholder process, Siemens shared three potential strategies for consideration as shown in **Error! Reference source not found.**below.

**Strategy 4 -** **Strategy 1** reflects a traditional and centralized energy program that emphasizes reliability and economic metrics.

**Strategy 5 -** **Strategy 2** reflects a distributed system of flexible generation, and micro or mini-grids and hardening of existing infrastructure around Puerto Rico, which emphasizes resiliency and closeness to the customer. In this strategy, most of the load is supplied from local supply resources that can be isolated from the remainder of island during a major event but still supply all or a portion of the nearby load. It is defined in terms of a minimum level of the load to be supplied by local resources (e.g., 80%).

**Strategy 6 -** **Strategy 3** reflects a hybrid of the first two strategies that embodies a combination of the benefits of Strategy 1 and Strategy 2. In this strategy, economies of scale are taken advantage of, and some of the load may be served under normal conditions from remote resources. In this strategy, the potential for greater levels of rotating load shed during a major event is greater than Strategy 2, but should result in lower operating costs.

**Exhibit 5-1. PREPA IRP Strategies**




To achieve the vision of a more renewable, resilient, and reliable Puerto Rico electric system, the IRP incorporates analysis of mini-grids, micro-grids, and grid modernization to systematically improve resiliency with pockets of critical loads served by distributed resources that can operate in both grid-connected and island modes. These mini-grids are proposed to be strategically sited to support clusters of critical transmission and distribution voltage loads, downstream of distribution and transmission vulnerabilities. The IRP seeks to balance low cost reliable operation under normal conditions and the ability to mitigate and achieve timely recovery from major disruptive events.

Stakeholders generally reached consensus that a strategy founded on distributed rather than centralized supply resources is more appropriate to Puerto Rico's situation because it provides a more resilient grid. Generally, participants viewed Strategy 3 ("hybrid strategy" of centralized and distributed generation) as a short- or medium-term step to Strategy 2 (a long-term mix of distributed and flexible generation in Puerto Rico where supply is located closer to load). Most stakeholders did not support pursuit of the centralized Strategy 1, except possibly as a reference point for comparison. On the other hand, some stakeholder groups requested that Strategy 1 be explicitly modeled as this strategy was thought to likely provide the least cost configuration. Larger centralized resources aligned with Strategy 1 were incorporated in the scenario that has all resources competing to provide the desired cost comparison information.

In addition to the IRP Regulation effective since April 24, 2018, the PREB issued orders on September 5 and September 18, 2018, regarding scenarios and other points of the IRP, including, but not limited to, a directive to consider Strategy 1. The regulation and orders speak for themselves, so they will not be summarized here, although they are referenced below.

For each strategy, a combination of assets were developed by putting constraints on the generation, transmission, and distribution assets that are available to Puerto Rico for a specific strategy. For example, a fully distributed strategy did not consider traditional high capacity generating assets such as large gas fueled combined cycle plants or diesel fueled assets. A partially distributed system or hybrid system considered only a limited amount of larger traditional generators.

## 5.3 Uncertainties

In addition, the IRP captures a series of uncertainties, including load growth, Distributed Energy Resources (DER), O&M[25] and capital costs of assets, fuel availability and price forecasts, energy policy and permitting, weather, energy efficiency, and PPOA termination or extension. The scenarios and sensitivities are designed to test each strategy against a combination of these uncertainties. The scenarios, sensitivities, and stochastics (for uncertainties assessment) are discussed below.

## 5.4 Scenarios

The PREB IRP Regulation defines scenarios as a combination of system requirements needed to serve load, commodity prices, capital costs, and risks that influence the choice of resources serving PREPA's future load. Each scenario constitutes a possible resource plan. Traditional uncertainties (e.g., load forecasts, fuel forecasts, and renewables capital costs) are also assessed via stochastic analysis, as described later in this report.

Based on extensive stakeholder engagement and consolidation of the September scenarios orders by PREB, PREPA considered a total of six scenarios as part of the 2018 IRP.

With respect of fuel infrastructure and renewables, the following scenarios are considered as outlined in Exhibit 5-2 and further described below.

*Scenario 1:* No new gas-fired generation is installed. The scenario uses the base case assumptions of solar and storage costs and availability.

*Scenario 2:* Gas to North: The land-based LNG at San Juan in the North is assumed to acquire the required permitting approval. The scenario uses the base case assumption of solar and storage costs and availability.

*Scenario 3:* Gas to Yabucoa (east) and to Mayagüez (west) through ship-based LNG and gas to the north is supplied through land-based LNG at San Juan. The land-based LNG at San Juan is assumed to acquire the required permitting approval. The scenario assumes the deeper drop (NREL Low Case) of solar and storage costs coupled with high availability of renewables (early ramp up).

*Scenario 4:* Gas to Yabucoa (east) and to Mayagüez (west) through ship-based LNG and gas to the north is supplied through land-based LNG at San Juan. The land-based LNG at San Juan is assumed to acquire the required permitting approval. The scenario uses the base case assumption of solar and storage costs and availability.

*Scenario 5:* Aguirre Offshore Gas Port (AOGP), gas to Yabucoa (east) and to Mayagüez (west) is supplied through ship-based LNG. Gas to the north is supplied through land-based LNG at San Juan which is assumed to achieve required permitting approval. The scenario uses the base case assumption of solar and storage costs and availability.

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[25] Operation and maintenance

*ESM:* Energy System Modernization (ESM); this is a plan advanced by PREPA and that includes a set of pre-defined investments decisions that considers ongoing RFP processes. The ESM is benchmarked against the formulated least cost plans. The investments included in the ESM plan reported include adjustments made during the analysis carried out under the IRP.

**Exhibit 5-2. PREPA IRP Scenario Definition**

| Scenario | New Gas | | | | Renewable & Storage | |
|---|---|---|---|---|---|---|
| | AOGP | Land-based LNG at San Juan | Ship-based LNG at Yabucoa | Ship-based LNG at Mayagüez | Costs | Availability |
| 1 | No | No | No | No | Reference | Reference |
| 2 | No | Yes | No | No | Reference | Reference |
| 3 | No | Yes | Yes | Yes | Low | High |
| 4 | No | Yes | Yes | Yes | Reference | Reference |
| 5 | Yes | Yes | Yes | Yes | Reference | Reference |
| ESM | No | Yes | Yes | Yes | Reference | Reference |

Some of the ESM decisions above are fixed and not subject to the LTCE selection. This includes the land based LNG terminal at San Juan and a new 300 MW Combined Cycle Gas Turbine (CCGT) by 2025 (or as early as possible); this will follow the conversion of San Juan 5&6 to gas, which is supported by the ship-based LNG that will be replaced by the land-based when commissioned. At Yabucoa a Ship-Based LNG terminal is to be developed and 300 MW CCGT is installed by 2025 (or as early as possible). At Mayagüez, a Ship-Based LNG terminal is developed, but the only fix decision is to convert the existing Aero units to be able to burn natural gas. The possibility of installing a CCGT is left as an option for the optimization process. The ESM also includes an additional smaller plant of approximately 100 MW in the north (modelled as 3x38 MW small CCGT) that can burn both natural gas and LPG (liquefied petroleum gas).

The following conditions and assumptions, unless specifically indicated to the contrary, will be modeled across all five scenarios and the ESM:

1. Load Forecast is treated via a Base, High and Low case. A stochastic analysis could be conducted as a follow-up analysis; however, as will be discussed later in this report, the High and Low cases allow identifying the decisions that would be affected by changes in the load growth and the path to account for this uncertainty.
2. Fuel forecast and costs of renewable and storage are treated via sensitivities and the modification on decisions identified.
3. The AES PPOA is assumed to expire in 2027 without renewal and the EcoEléctrica PPOA is assumed to be renewed in 2022 with modifications on the contract to prevent the immediate retirement of the plan. These modifications basically include a reduction of the fixed payments to 55% (new 2022 payment $108 million down from 240 million the prior year) and EcoEléctrica being able to cycle in and out of service as required to integrate renewable. On the other hand, after expiration of the existing contract the energy payments are assumed to follow market conditions, instead of the reduced prices now in place. Note that with the payment EcoEléctrica was still found to be retired over the medium term due to the entry of an F-Class CCGT. Hence,

for the ESM plan that does not considers this option, the payment was reduced to 60% (new 2022 payment $88 million down from 240 million the prior year).

4. Energy Efficiency is assumed to meet the requirement of the IRP Regulation of 2% per year incremental savings attributable to new energy efficiency programs.
5. Peaking generation was added to all LTCEs under Strategy 2 and Strategy 3ensure that the critical loads located in each of the recommended eight electric islands into which the system would be segregated after a major storm (the MiniGrids), could be served on grid isolated mode. This peaking generation along with the renewable generation and the storage in the MiniGrid would serve the priority loads and as much as possible of the balance of the load. Strategy 1 did not have this requirement and was used to identify the tradeoff between benefits and costs (value of loss load) of relying on central generation. The ESM had also these GT's as a fixed decision.

It should be noted that the possibility of achieving permitting approval for any of the LNG terminal above does not mean that the option of gas generation was automatically be selected nor its size.

## 5.5 Sensitivities

Sensitivity analyses were used to isolate the impacts of certain important variables while holding other assumptions constant. For the 2018 IRP, six sensitivities were included in the core scope of this study[26], as shown in Exhibit 5-3. PREPA IRP Sensitivity Definition and further described below

*Sensitivity 1:* Deeper reduction in cost of solar and storage, coupled with high availability of storage and solar. In Sensitivity 1, higher yearly limits of PV/BESS (photovoltaic / battery energy storage system) are assumed. See Exhibit 6-27 for the limits of this Sensitivity 1. As a reference, Exhibit 6-28 has the limits for the core LTCE and Exhibit 6-29 the limits for the ESM.

*Sensitivity 2:* Lower energy efficiency penetration (~1% reduction per year instead of 2%).

*Sensitivity 3:* Economic retirement of AES and EcoEléctrica regardless of contract term. In practice, if AES is not forced to retire, it will not retire, and as indicated earlier EcoEléctrica's contract needs to be modified.

*Sensitivity 4:* Ship-based LNG at San Juan could achieve permitting approval. The ship-based LNG at San Juan can basically supply the conversion of San Juan 5&6 and provide limited gas to other developments. It has reduced capacity in comparison to the land-based LNG option.

*Sensitivity 5:* High gas prices.

*Sensitivity 6:* High cost of solar and storage.

[26] Once this study is completed, more sensitivities models and stochastic analysis could be run as well as running the core sensitivities on other strategies, as required by the PREB.

**Exhibit 5-3. PREPA IRP Sensitivity Definition**

| Sensitivity | Solar/BESS | Energy Efficiency | PPOAs | Gas | | Solar/BESS |
|---|---|---|---|---|---|---|
| | Low Cost | Low EE | Economic Retirement of AES and EcoEléctrica | Ship-based LNG at San Juan | High Gas Prices | High Cost |
| 1 | ◆ | | | | | |
| 2 | | ◆ | | | | |
| 3 | | | ◆ | | | |
| 4 | | | | ◆ | | |
| 5 | | | | | ◆ | |
| 6 | | | | | | ◆ |

Additional important sensitivities were proposed by stakeholders, including no RPS (renewable portfolio standard – Act 82-2010) and/or postponed MATS compliance (US EPA Mercury and Air Toxics Standards regulation) to show the cost of compliance. However, all LTCE plans and the ESM exceeded the RPS limits (in some cases widely). Also, most MATS incompliant units were retired on economics rather than compliance reasons, which forced the units to retire by 2025.

Finally, it is recognized that additional sensitivities could be included as gas to the north and south via pipelines, emissions prices ($CO_2$), and cost of capital.

## 5.6 Portfolio Cases

Portfolio cases are unique combinations of scenarios and strategies. Exhibit 5-4below illustrates the 32 portfolio cases to be modeled in the core IRP. The portfolio cases are named under the convention of "Scenario ID + Strategy ID + Sensitivity ID + Load Forecast (High, Base or Low)".

It can be noted below that for Scenarios 1 to 4 and certain sensitivities, the portfolios cases and the resulting LTCE plan is assessed for the High, Base, and Low load growth forecast. Strategy 2 and Strategy 3 are considered for the Scenarios 1 to 4 and as Scenario 5 is designed not to have any restrictions, the Strategy 1 is used. Strategy 3 is used for most of the sensitivities.

Regarding the 32 portfolio cases and associated model treatment, the LTCE is run in all portfolios cases, the detailed nodal runs are done on the Base Case, and the PSS®E assessments are done in those cases that are expected to result in maximum stresses of the system, either in terms of large amounts of renewable online or heavier use of the transmission facilities.

**Exhibit 5-4. PREPA 2018 IRP Portfolio Cases Summary**

| Count | Case ID | Scenario | Strategy | Sensitivity | Load | Aurora LTCE | Nodal Run | PSSE |
|---|---|---|---|---|---|---|---|---|
| 1 | S1S2B | 1 | 2 | | Base | Yes | Yes | |
| 2 | S1S2H | 1 | 2 | | High | Yes | | |
| 3 | S1S2L | 1 | 2 | | Low | Yes | | |
| 4 | S1S3B | 1 | 3 | | Base | Yes | | |
| 5 | S1S3H | 1 | 3 | | High | Yes | | |
| 6 | S1S3L | 1 | 3 | | Low | Yes | | |
| 7 | S1S2S1B | 1 | 2 | 1 | Base | No | | |
| 8 | S1S2S2B | 1 | 2 | 2 | Base | Yes | | |
| 9 | S1S2S3B | 1 | 2 | 3 | Base | Yes | | |
| 10 | S1S1B | 1 | 1 | | Base | Yes | | |
| 11 | S3S2B | 3 | 2 | | Base | Yes | | |
| 12 | S3S2H | 3 | 2 | | High | Yes | | |
| 13 | S3S2L | 3 | 2 | | Low | Yes | | |
| 14 | S3S3B | 3 | 3 | | Base | Yes | | |
| 15 | S3S3H | 3 | 3 | | High | Yes | | |
| 16 | S3S3L | 3 | 3 | | Low | Yes | | |
| 17 | S4S2B | 4 | 2 | | Base | Yes | Yes | Yes |
| 18 | S4S2H | 4 | 2 | | High | Yes | | |
| 19 | S4S2L | 4 | 2 | | Low | Yes | | |
| 20 | S4S3B | 4 | 3 | | Base | Yes | | |
| 21 | S4S3H | 4 | 3 | | High | Yes | | |
| 22 | S4S3L | 4 | 3 | | Low | Yes | | |
| 23 | S4S2S3B | 4 | 2 | 3 | Base | Yes | | |
| 24 | S4S2S4B | 4 | 2 | 4 | Base | Yes | | |
| 25 | S4S2S5B | 4 | 2 | 5 | Base | Yes | | |
| 26 | S4S2S6B | 4 | 2 | 6 | Base | Yes | Yes | |
| 27 | S4S1B | 4 | 1 | | Base | Yes | | no |
| 28 | S5S1B | 5 | 1 | | Base | Yes | Yes | |
| 29 | S5S1S5B | 5 | 1 | 5 | Base | Yes | | |
| 30 | ESM Plan | 4 | 2 | | Base | | Yes | Yes |
| 31 | ESM high | 4 | 2 | | High | | | |
| 32 | ESM low | 4 | 2 | | Low | | | |

Part
6

# New Resource Options

## 6.1 Overview of New Generation Resources

Siemens and PREPA discussed the key criteria in developing new generation resources to allow for system flexibility and reliability, including the capability to accommodate large blocks of renewable capacity, primarily solar. Siemens conducted technology screening to identify technically feasible and commercially viable generation resources that could be used as building blocks in constructing generation asset portfolios. For this reason, the technology screening focuses on resource options that could meet PREPA's new generation resource requirements, including:

1. Size of the new generation resource, which is informed by factors including size of the maximum contingency and local reserve requirements, load profile, retirement of existing resources, and expiration of PPOA, etc.

2. Resource type: base load, intermediate, intermittent, or peaking resources, largely determined by renewable generation integration.

3. Characteristics: ramping rate and daily cycling capability.

4. Fuel type: fossil-fueled (natural gas, diesel or dual fuel with natural gas as primary and diesel as backup).

5. Local considerations: altitude, temperature, natural wind or solar resources, etc.

6. The technology selection on a broader perspective considered a combination of dispatchable fossil-fueled generation resources, storage and renewable technologies.

7. Utility scale solar and storage for new builds of renewable resources.

8. Fossil-fueled resources included CCGT, GT, reciprocating internal combustion engines (RICE) and CHP. Siemens relied upon information exchanged with PREPA, performance and cost information provided by vendors, as well as GT Pro[27] software performance and cost calculations in estimating representative generation resources.

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[27] GT Pro is a software program licensed by Thermoflow for sizing and designing simple cycle, combined cycle, cogeneration, GT, CCGT, CHP, and other types of power generation units. GT Pro was used to determine, among other measures, plant output, heat rate, duct firing capacity, and capital costs for the specified site conditions and available fuels.

## 6.2 New Fossil-Fired Generation Resources

### 6.2.1 Generation Options Development and Sizing

A three-step process was used to determine generating unit characteristics and select technologies for portfolios as discussed below.

First, Siemens performed a technology screening. GTs and their corresponding CCGT plants come in discrete sizes based on equipment offerings from a limited number of worldwide manufacturers. Siemens' approach was to screen a large number of available GT and CCGT configurations from all major manufacturers like GE, Mitsubishi, Hitachi, Siemens, and Solar Turbines, based mainly on published performance of available GT and CCGT generating units at ISO conditions (59°F, 60 percent relative humidity, and sea level) with wet cooling towers on natural gas fuel. All CCGT cases were evaluated in 1 x 1 Power Block configuration, i.e., a single train of GT, Heat Recovery Steam Generator (HRSG) and Steam Turbine Generator (STG).[28] A limited number of cases from various manufacturers were selected for analysis in GT Pro software.

Second, from this group, certain configurations were selected for modeling in GT Pro to obtain performance specific to PREPA site conditions (85°F, 70 percent relative humidity, and 25 or 1,000 feet above mean sea level[29]) on natural gas and distillate oil (also known as Diesel or Light Fuel Oil - LFO), with and without duct firing, and with dry cooling as appropriate for the application. New CCGTs assumed dry cooling with Air Cooled Condensers (ACCs). Siemens criterion was to design and size the plant based on liquid (distillate or diesel) fuel, then to determine corresponding performance of the same design operating on natural gas. It should be noted that this likely resulted in somewhat less attractive performance than for a plant designed solely for natural gas fuel. Future optimization is possible for scenarios using CCGT with natural gas as primary fuel.

Finally, GT Pro performance estimates were used to select which configurations to consider in developing the generation portfolios for capacity expansion in AURORA and the subsequent nodal analysis in AURORA-Nodal.

When Siemens selected new generation options for inclusion in portfolios, a particular unit design based on an actual product is chosen as representative of a class of similar units. In all cases, there is at least one additional unit available from a different manufacturer with sufficiently similar characteristics that competitive bidding would be possible at the time a project is implemented. The important point is that the generating units used for the IRP purposes do not lock PREPA into any particular manufacturer for project implementation and further optimization can be achieved at the time of implementation.

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[28] 1 x 1 Power Block projects give siting flexibility in modeling. If multiple trains are needed in same location, later optimizations can be performed to evaluate whether 2 x 1 or 3 x 1 fit the operating profile and are more economic than 1 x 1.

[29] Large plants near coast were set at 25 ft AMSL to be above storm surge. Smaller plants that might be used at interior sites were set at 1,000 ft AMSL.

For the RICE case, Siemens obtained published Wartsila performance information for a large engine capable of dual fuel (natural gas and diesel) operation. Siemens made a manual adjustment for site conditions. This engine requires about 0.5 to 1.0 percent diesel pilot fuel when operating on natural gas. Siemens made a small adjustment to the RICE natural gas heat rate to account for the higher cost of the pilot fuel.

All selected generation resources are analyzed based on dual fuel capability with natural gas and diesel, with gas being the primary fuel when available and an option when not. For dual fuel units, the unit output and heat rate are somewhat different depending on the fuel type. The representative options selected by Siemens are discussed in the next subsection.

### 6.2.2 Representative Future Generation Resources Characteristics

As indicated above, Siemens developed key operational parameters of the representative future generation resources, primarily relying on published vendor information as well as vendor-supplied performance and cost information available in GT Pro performance software.

Exhibit 6-1 presents the operational parameters for an H Class Combined Cycle (GE S107HA.01) unit. Exhibit 6-2 and Exhibit 6-3 present the operational parameters of a larger F Class Combined Cycle (CCGT - GE S107F.05) unit and a smaller F Class Combined Cycle (CCGT - GE S107F.04) unit, respectively. Exhibit 6-4 presents the operational parameters for medium-sized combined cycle (Hitachi H-100). These units have a short minimum run time and hence can cycle in and out of service daily. Also, the minimum capacity is 39 to 48 percent of the duct fired capacity allowing a significant reduction in output before the units must be turned off. In addition, the units can ramp up from their minimum to the maximum capacity in 3.5 to 8 minutes.

**Exhibit 6-1. H Class Combined Cycle (GE S107HA.01) Operational Assumptions**

| Generation Unit Type | Unit | H Class CC (GE S107HA.01) | |
|---|---|---|---|
| | | Natural Gas | Diesel |
| Max. Unit Capacity w/o Duct Fire | MW | 374 | 365 |
| Max. Unit Capacity with Duct Fire | MW | 449 | 438 |
| Min. Unit Capacity | MW | 176 | 172 |
| Min. Unit Capacity (% of Duct F Capacity) | % | 39% | 39% |
| Fixed O&M Expense | 2018 $/kW-year | 22.09 | 22.09 |
| Variable O&M Expense | 2018 $/MWh | 1.75 | 1.75 |
| Heat Rate at 100% Rated Capacity (Unfired) | MMBtu/MWh | 6.77 | 6.60 |
| Heat Rate at Full Duct Fire Capacity | MMBtu/MWh | 7.09 | 6.90 |
| Unit Capacity Degradation | % | 2.5% | 2.5% |
| Unit Heat Rate Degradation | % | 1.5% | 1.5% |
| Annual Required Maintenance Time | Hours per Year | 360 | 360 |
| Unit Forced Outage Rate | % | 2.0% | 2.0% |
| Unit Forced Outage Duration | Hours | 40 | 40 |
| Minimum Downtime | Hours | 2 | 2 |
| Minimum Runtime | Hours | 2 | 2 |
| Ramp Up Rate | MW/minute | 40 | 40 |
| Ramp Down Rate | MW/minute | 40 | 40 |
| Regulation Minimum Range | MW | 176 | 172 |
| Regulation Maximum Range | MW | 449 | 438 |
| Regulation Ramp Rate | MW/minute | 40 | 40 |

## Exhibit 6-2. F Class CCGT - Larger (GE S107F.05) Operational Assumptions

| Generation Unit Type | Unit | F Class CC - Larger (GE S107F.05) | |
|---|---|---|---|
| | | Natural Gas | Diesel |
| Max. Unit Capacity w/o Duct Fire | MW | 303 | 295 |
| Max. Unit Capacity with Duct Fire | MW | 369 | 361 |
| Min. Unit Capacity | MW | 172 | 168 |
| Min. Unit Capacity (% of Duct F Capacity) | % | 47% | 47% |
| Fixed O&M Expense | 2018 $/kW-year | 22.09 | 22.09 |
| Variable O&M Expense | 2018 $/MWh | 1.75 | 1.75 |
| Heat Rate at 100% Rated Capacity (Unfired) | MMBtu/MWh | 7.25 | 7.07 |
| Heat Rate at Full Duct Fire Capacity | MMBtu/MWh | 7.53 | 7.32 |
| Unit Capacity Degradation | % | 2.5% | 2.5% |
| Unit Heat Rate Degradation | % | 1.5% | 1.5% |
| Annual Required Maintenance Time | Hours per Year | 360 | 360 |
| Unit Forced Outage Rate | % | 2% | 2% |
| Unit Forced Outage Duration | Hours | 40 | 40 |
| Minimum Downtime | Hours | 2 | 2 |
| Minimum Runtime | Hours | 2 | 2 |
| Ramp Up Rate | MW/minute | 40 | 40 |
| Ramp Down Rate | MW/minute | 40 | 40 |
| Regulation Minimum Range | MW | 172 | 168 |
| Regulation Maximum Range | MW | 369 | 361 |
| Regulation Ramp Rate | MW/minute | 40 | 40 |

## Exhibit 6-3. F Class CCGT - Smaller (GE S107F.04) Operational Assumptions

| Generation Unit Type | Unit | F Class CC - Smaller (GE S107F.04) | |
|---|---|---|---|
| | | Natural Gas | Diesel |
| Max. Unit Capacity w/o Duct Fire | MW | 251 | 245 |
| Max. Unit Capacity with Duct Fire | MW | 302 | 296 |
| Min. Unit Capacity | MW | 144 | 141 |
| Min. Unit Capacity (% of Duct Fired Capacity | % | 48% | 48% |
| Fixed O&M Expense | 2018 $/kW-year | 22.09 | 22.09 |
| Variable O&M Expense | 2018 $/MWh | 1.75 | 1.75 |
| Heat Rate at 100% Rated Capacity (Unfired) | MMBtu/MWh | 7.27 | 7.09 |
| Heat Rate at Full Duct Fire Capacity | MMBtu/MWh | 7.55 | 7.34 |
| Unit Capacity Degradation | % | 2.5% | 2.5% |
| Unit Heat Rate Degradation | % | 1.5% | 1.5% |
| Annual Required Maintenance Time | Hours per Year | 360 | 360 |
| Unit Forced Outage Rate | % | 2% | 2% |
| Unit Forced Outage Duration | Hours | 40 | 40 |
| Minimum Downtime | Hours | 2 | 2 |
| Minimum Runtime | Hours | 2 | 2 |
| Ramp Up Rate | MW/minute | 30 | 30 |
| Ramp Down Rate | MW/minute | 30 | 30 |
| Regulation Minimum Range | MW | 144 | 141 |
| Regulation Maximum Range | MW | 251 | 245 |
| Regulation Ramp Rate | MW/minute | 30 | 30 |

**Exhibit 6-4. Medium CCGT Hitachi (H-100) Operational Assumptions**

| Generation Unit Type | Unit | Medium CC (Hitachi H-100) | |
|---|---|---|---|
| | | Natural Gas | Diesel |
| Max. Unit Capacity w/o Duct Fire | MW | 116 | 113 |
| Max. Unit Capacity with Duct Fire | MW | 144 | 141 |
| Min. Unit Capacity | MW | 61 | 60 |
| Min. Unit Capacity (% of Duct F Capacity) | % | 42% | 42% |
| Fixed O&M Expense | 2018 $/kW-year | 33.12 | 33.12 |
| Variable O&M Expense | 2018 $/MWh | 2.61 | 2.61 |
| Heat Rate at 100% Rated Capacity (Unfired) | MMBtu/MWh | 7.76 | 7.56 |
| Heat Rate at Full Duct Fire Capacity | MMBtu/MWh | 8.25 | 8.02 |
| Unit Capacity Degradation | % | 2.5% | 2.5% |
| Unit Heat Rate Degradation | % | 1.5% | 1.5% |
| Annual Required Maintenance Time | Hours per Year | 360 | 360 |
| Unit Forced Outage Rate | % | 2% | 2% |
| Unit Forced Outage Duration | Hours | 40 | 40 |
| Minimum Downtime | Hours | 2 | 2 |
| Minimum Runtime | Hours | 2 | 2 |
| Ramp Up Rate | MW/minute | 15 | 15 |
| Ramp Down Rate | MW/minute | 15 | 15 |
| Regulation Minimum Range | MW | 61 | 60 |
| Regulation Maximum Range | MW | 144 | 141 |
| Regulation Ramp Rate | MW/minute | 15 | 15 |

Exhibit 6-5, Exhibit 6-6 and Exhibit 6-7 present the operational parameters of the small combined cycle units (GE LM6000 DLE, GE LM2500+G4 SAC, and GE LM2500 SAC) considered in the IRP. As with the larger units, these units have a short minimum run time and can cycle in and out of service daily. Their minimum capacity is 42 to 51 percent of the duct fired capacity, allowing a significant reduction in output before the units must be turned off. These units can ramp up from their minimum to the maximum normal capacity in about 30 seconds. The GE LM2500+G4 SAC was modeled with the capability of burning LPG and natural gas when offered as an option for the North and in the ESM plan as discussed later in this report.

## Exhibit 6-5. Small CCGT (GE LM6000 DLE) (Duct Fired) Operational Assumptions

| Generation Unit Type | Unit | Small CC (GE LM6000 DLE) | |
|---|---|---|---|
| | | Natural Gas | Diesel |
| Max. Unit Capacity w/o Duct Fire | MW | 51 | 49 |
| Max. Unit Capacity with Duct Fire | MW | 66 | 63 |
| Min. Unit Capacity | MW | 27 | 26 |
| Min. Unit Capacity (% of Duct F Capacity) | % | 42% | 42% |
| Fixed O&M Expense | 2018 $/kW-year | 36.13 | 36.13 |
| Variable O&M Expense | 2018 $/MWh | 5.29 | 5.29 |
| Heat Rate at 100% Rated Capacity | MMBtu/MWh | 7.83 | 7.65 |
| Heat Rate at Full Duct Fire Capacity | MMBtu/MWh | 8.62 | 8.37 |
| Unit Capacity Degradation | % | 2.5% | 2.5% |
| Unit Heat Rate Degradation | % | 1.5% | 1.5% |
| Annual Required Maintenance Time | Hours per Year | 180 | 180 |
| Unit Forced Outage Rate | % | 2% | 2% |
| Unit Forced Outage Duration | Hours | 40 | 40 |
| Minimum Downtime | Hours | 2 | 2 |
| Minimum Runtime | Hours | 2 | 2 |
| Ramp Up Rate | MW/minute | 50 | 50 |
| Ramp Down Rate | MW/minute | 50 | 50 |
| Regulation Minimum Range | MW | 27 | 26 |
| Regulation Maximum Range | MW | 66 | 63 |
| Regulation Ramp Rate | MW/minute | 50 | 50 |

Source: Siemens

## Exhibit 6-6. Small CCGT (GE LM2500 +G4 SAC) Operational Assumptions

| Generation Unit Type | Unit | Small CC (GE LM2500+ G4 SAC) | |
|---|---|---|---|
| | | Natural Gas | Diesel |
| Max. Unit Capacity | MW | 38 | 38 |
| Min. Unit Capacity | MW | 19 | 20 |
| Min. Unit Capacity (% of max Capacity) | % | 51% | 51% |
| Fixed O&M Expense | 2018 $/kW-year | 41.33 | 41.33 |
| Variable O&M Expense | 2018 $/MWh | 3.12 | 3.12 |
| Heat Rate at 100% Rated Capacity | MMBtu/MWh | 8.34 | 8.08 |
| Annual Required Maintenance Time | Hours per Year | 180 | 180 |
| Unit Forced Outage Rate | % | 2% | 2% |
| Unit Forced Outage Duration | Hours | 40 | 40 |
| Minimum Downtime | Hours | 2 | 2 |
| Minimum Runtime | Hours | 2 | 2 |
| Ramp Up Rate | MW/minute | 30 | 30 |
| Ramp Down Rate | MW/minute | 30 | 30 |
| Regulation Minimum Range | MW | 19 | 20 |
| Regulation Maximum Range | MW | 38 | 38 |
| Regulation Ramp Rate | MW/minute | 30 | 30 |

### Exhibit 6-7. Small CCGT (GE LM2500 SAC) Operational Assumptions

| Generation Unit Type | Unit | Small CC (GE LM2500 SAC) | |
|---|---|---|---|
| | | Natural Gas | Diesel |
| Max. Unit Capacity | MW | 29 | 28 |
| Min. Unit Capacity | MW | 15 | 14 |
| Min. Unit Capacity (% of max Capacity) | % | 51% | 51% |
| Fixed O&M Expense | 2018 $/kW-year | 42.49 | 42.49 |
| Variable O&M Expense | 2018 $/MWh | 3.12 | 3.12 |
| Heat Rate at 100% Rated Capacity | MMBtu/MWh | 8.69 | 8.46 |
| Unit Capacity Degradation | % | 2.5% | 2.5% |
| Unit Heat Rate Degradation | % | 1.5% | 1.5% |
| Annual Required Maintenance Time | Hours per Year | 180 | 180 |
| Unit Forced Outage Rate | % | 2% | 2% |
| Unit Forced Outage Duration | Hours | 40 | 40 |
| Minimum Downtime | Hours | 2 | 2 |
| Minimum Runtime | Hours | 2 | 2 |
| Ramp Up Rate | MW/minute | 30 | 30 |
| Ramp Down Rate | MW/minute | 30 | 30 |
| Regulation Minimum Range | MW | 15 | 14 |
| Regulation Maximum Range | MW | 29 | 28 |
| Regulation Ramp Rate | MW/minute | 30 | 30 |

Exhibit 6-8, Exhibit 6-9 and Exhibit 6-10 present the operational parameters of the GT units (Mobile, GE LM6000 DLE, and GE LM2500 SAC) considered in the IRP, which can cycle in and out of service frequently. The units in Exhibit 6-8 are mobile units and are good candidates for replacement of the existing Frame 5 units (21 MW each).

These GT's typically have a minimum capacity of 50% of the maximum (due to emissions limitations) and can ramp up from minimum to maximum capacity in less than 25 seconds.

### Exhibit 6-8. Simple Cycle Mobile Unit

| Generation Unit Type | Unit | FT8 MOBILEPAC 25 DLN | |
|---|---|---|---|
| | | Natural Gas | Diesel |
| Max. Unit Capacity | MW | 23.2 | 22.6 |
| Min. Unit Capacity | MW | 11.9 | 11.3 |
| Fixed O&M Expense | 2018 $/kW-year | 38.62 | 38.62 |
| Variable O&M Expense | 2018 $/MWh | 3.12 | 3.12 |
| Heat Rate at 100% Rated Capacity | MMBtu/MWh | 11.12 | 10.96 |
| Unit Capacity Degradation | % | 2.50% | 2.50% |
| Unit Heat Rate Degradation | % | 1.50% | 1.50% |
| Annual Required Maintenance Time | Hours per Year | 180 | 180 |
| Unit Forced Outage Rate | % | 2% | 2% |
| Unit Forced Outage Duration | Hours | 40 | 40 |
| Minimum Downtime | Hours | 2 | 2 |
| Minimum Runtime | Hours | 2 | 2 |
| Ramp Up Rate | MW/minute | 30 | 30 |
| Ramp Down Rate | MW/minute | 30 | 30 |
| Regulation Minimum Range | MW | 11.9 | 11.3 |
| Regulation Maximum Range | MW | 23.8 | 22.6 |
| Regulation Ramp Rate | MW/minute | 30 | 30 |

**Exhibit 6-9. Simple Cycle Peaker GT (GE LM6000 DLE) Operational Assumptions**

| Generation Unit Type | Unit | SC Peaker (GE LM6000 DLE) | |
|---|---|---|---|
| | | Natural Gas | Diesel |
| Max. Unit Capacity | MW | 41 | 39 |
| Min. Unit Capacity | MW | 21 | 19 |
| Min. Unit Capacity (% of Max Capacity) | % | 50% | 50% |
| Fixed O&M Expense | 2018 $/kW-year | 32.85 | 32.85 |
| Variable O&M Expense | 2018 $/MWh | 5.29 | 5.29 |
| Heat Rate at 100% Rated Capacity | MMBtu/MWh | 9.83 | 9.68 |
| Unit Capacity Degradation | % | 2.5% | 2.5% |
| Unit Heat Rate Degradation | % | 1.5% | 1.5% |
| Annual Required Maintenance Time | Hours per Year | 180 | 180 |
| Unit Forced Outage Rate | % | 0.02 | 0.02 |
| Unit Forced Outage Duration | Hours | 40 | 40 |
| Minimum Downtime | Hours | 2 | 2 |
| Minimum Runtime | Hours | 2 | 2 |
| Ramp Up Rate | MW/minute | 50 | 50 |
| Ramp Down Rate | MW/minute | 50 | 50 |
| Regulation Minimum Range | MW | 21 | 19 |
| Regulation Maximum Range | MW | 41 | 39 |
| Regulation Ramp Rate | MW/minute | 50 | 50 |

**Exhibit 6-10. Simple Cycle Peaker GT (GE LM2500 SAC) Operational Assumptions**

| Generation Unit Type | Unit | SC Peaker (GE LM2500 SAC) | |
|---|---|---|---|
| | | Natural Gas | Diesel |
| Max. Unit Capacity | MW | 22 | 21 |
| Min. Unit Capacity | MW | 11 | 11 |
| Min. Unit Capacity (% of Max Capacity) | % | 50% | 50% |
| Fixed O&M Expense | 2018 $/kW-year | 38.63 | 38.63 |
| Variable O&M Expense | 2018 $/MWh | 3.12 | 3.12 |
| Heat Rate at 100% Rated Capacity | MMBtu/MWh | 11.49 | 11.14 |
| Unit Capacity Degradation | % | 2.5% | 2.5% |
| Unit Heat Rate Degradation | % | 1.5% | 1.5% |
| Annual Required Maintenance Time | Hours per Year | 180 | 180 |
| Unit Forced Outage Rate | % | 0.02 | 0.02 |
| Unit Forced Outage Duration | Hours | 40 | 40 |
| Minimum Downtime | Hours | 2 | 2 |
| Minimum Runtime | Hours | 2 | 2 |
| Ramp Up Rate | MW/minute | 30 | 30 |
| Ramp Down Rate | MW/minute | 30 | 30 |
| Regulation Minimum Range | MW | 11 | 11 |
| Regulation Maximum Range | MW | 22 | 21 |
| Regulation Ramp Rate | MW/minute | 30 | 30 |

Source: Siemens

Exhibit 6-11 presents the operational parameters for the RICE technologies, which are very flexible, able to cycle frequently, and have low minimum loading and very fast loading rates.

**Exhibit 6-11. Reciprocating Engine Operational Assumptions**

| Generation Unit Type | Unit | Reciprocating Engine | |
|---|---|---|---|
| | | Natural Gas | Diesel |
| Max. Unit Capacity | MW | 16 | 16 |
| Min. Unit Capacity | MW | 2 | 2 |
| Min. Unit Capacity (% of Max Capacity) | % | 10% | 10% |
| Fixed O&M Expense | 2018 $/kW-year | 28.98 | 28.98 |
| Variable O&M Expense | 2018 $/MWh | 10.33 | 10.33 |
| Heat Rate at 100% Rated Capacity | MMBtu/MWh | 8.53 | 8.89 |
| Unit Capacity Degradation | % | 1.0% | 1.0% |
| Unit Heat Rate Degradation | % | 0.5% | 0.5% |
| Annual Required Maintenance Time | Hours per Year | 360 | 360 |
| Unit Forced Outage Rate | % | 0.02 | 0.02 |
| Unit Forced Outage Duration | Hours | 40 | 40 |
| Minimum Downtime | Hours | 2 | 2 |
| Minimum Runtime | Hours | 2 | 2 |
| Ramp Up Rate | MW/minute | 2.5 | 2.5 |
| Ramp Down Rate | MW/minute | 2.5 | 2.5 |
| Regulation Minimum Range | MW | 5 | 5 |
| Regulation Maximum Range | MW | 16 | 16 |
| Regulation Ramp Rate | MW/minute | 2.5 | 2.5 |

Source: Siemens

As discussed, these selections are representative of each particular technology class and do not represent final recommendations of particular equipment or manufacturer. Exact sizing, configuration and performance should be optimized when an actual generation project is planned and implemented. But for planning purposes, these units demonstrate how different representative technologies would fit in the overall dispatch analysis. Output and heat rate degradation are applied as a single adjustment to the "New and Clean" performance to represent annual average performance over the generating unit's operating life.

Combined Heat and Power (CHP) was also considered as an option and this is discussed in Appendix 4: Demand-Side Resources.

### 6.2.2.1 Existing Fleet Considerations

In this IRP, no repowering of existing units is considered due to the complications associated with trying to "recycle" aged infrastructure. However, the fuel conversion of San Juan 5&6 was considered as a committed decision and there is the possibility of fuel conversions of the Aguirre CCGT. For the fuel conversion candidates, the capital costs assumptions are presented in Exhibit 6-12.

**Exhibit 6-12. Fuel Conversion Projects Capital Costs Assumptions**

| Dual Fuel Conversion Projects | Capital Costs (thousand 2018$) |
|---|---|
| Aguirre 1 CCGT Dual Fuel Conversion | 25,371 |
| Aguirre 2 CCGT Dual Fuel Conversion | 25,371 |

Source: Siemens

### 6.2.2.2 Representative Future Generation Resources Capital Costs

Capital costs for the representative future generation resources are key parameters in the IRP models. Siemens developed the capital costs assumptions using the PEACE capital cost estimating module associated with GT Pro software. PEACE uses equipment selection and sizing as determined in GT Pro to estimate equipment and installation costs, including associated costs such as foundations, piping, wiring, buildings, etc. Other components including contractor engineering, commissioning, overhead, escalation, contingency and fees are added to determine the Engineering, Procurement and Construction (EPC) price. Owner's costs for development, permitting and legal/contracting activities, and cost escalation were included in PEACE. Most power projects implemented by private developers on a project non-recourse financing basis, incur total development and financing costs, including Interest during Construction, financing fees, project management, O&M mobilization, startup fuels and consumables, etc. PEACE included 9 percent of EPC for development costs. Also, PEACE includes certain adjustments to labor productivity and labor and materials costs based on project location. However, the program does not include adjustments specific to Puerto Rico costs. Siemens adopted the U.S. Department of Defense Area Cost Factor of 16 percent for Puerto Rico. This adjustment was inserted into PEACE as a user input and it was applied against equipment, material and labor costs to reflect delivery or local purchase and installation of equipment and materials for the project.

PEACE cost estimates are not as accurate as obtaining project specific equipment and construction costs estimates from suppliers and contractors, but are suitable for planning purposes and provide a consistent approach across all generation resource options. The PEACE cost estimates also reflect the specific configuration and sizing of options, such as duct firing and Air-Cooled Condensers, which need to be considered when factoring costs based on other projects whose configurations may vary. Exhibit 6-13 shows the estimated all-in capital costs for the selected representative technologies.

**Exhibit 6-13. New Generation Resources Capital Costs**

| Representative New Resource Candidates | Natural Gas Fired | | Diesel Fired | |
|---|---|---|---|---|
| | Capacity (MW) | Capital Costs (2018$/KW) | Capacity (MW) | Capital Costs (2018$/KW) |
| H Class CCGT (GE S107HA.01) | 449 | $899 | 438 | $921 |
| F Class CCGT (GE S107F.04) (Duct Fired) | 302 | $994 | 296 | $1,017 |
| F Class CCGT (GE S107F.05) (Duct Fired) | 369 | $927 | 361 | $948 |
| Medium CCGT (Hitachi H-100) (Duct Fired) | 144 | $1,250 | 141 | $1,275 |
| Small CCGT (GE LM6000 DLE) (Duct Fired) | 66 | $1,658 | 63 | $1,729 |
| Small CCGT (GE LM2500+ G4 SAC) (Duct Fired) | 38 | $1,798 | 38 | $1,812 |
| Small CCGT (GE LM2500 SAC) (Duct Fired) | 29 | $2,010 | 28 | $2,052 |
| Aero/Small GT Peaker (GE LM6000 DLE) | 41 | $1,375 | 39 | $1,444 |
| Aero/Small GT Peaker (GE LM2500 SAC) | 22 | $1,627 | 21 | $1,689 |
| Small CHP (Solar Turbines Mars 100) | 9 | $2,651 | 9 | $2,639 |
| RICE (Wartsila 18V50DF) | 16 | $1,612 | 16 | $1,612 |

Source: Siemens

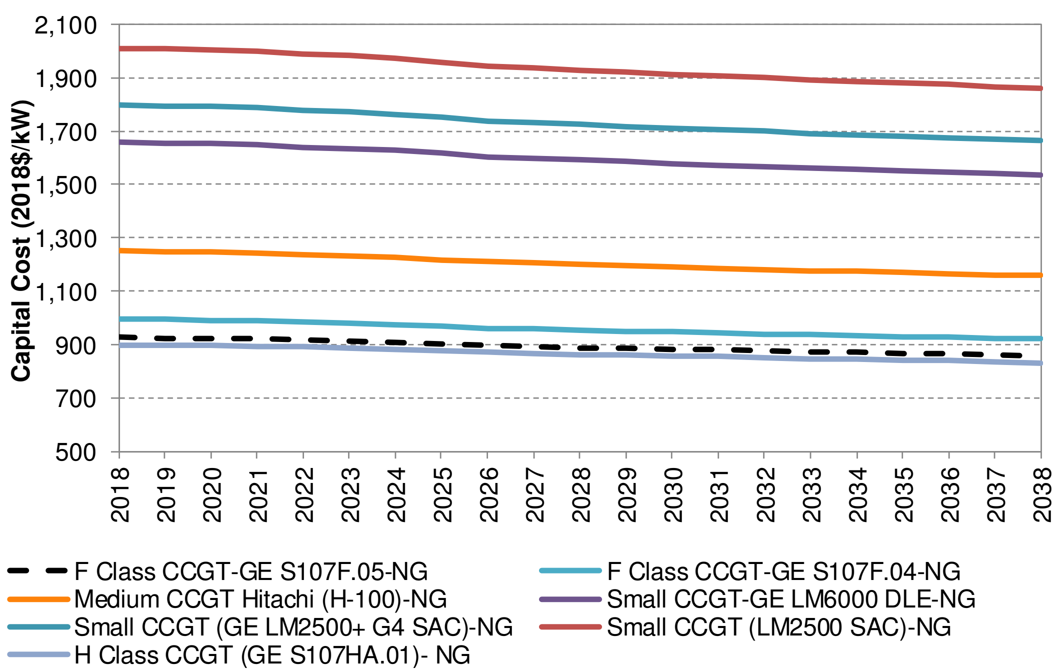
For the replacement of the 21 MW Frame 5 units using the mobile units (FT8 MOBILEPAC 25 DLN) presented earlier, there are capital cost differences whether it is replacing an existing unit or adding another unit on site. This is presented below.

**Exhibit 6-14. New Generation Resources Capital Costs**

| Name | Existing Units | Zone | Capex ($/kW) Existing | Capex ($/kW) Additional |
|---|---|---|---|---|
| Daguao | 2 | Carolina | 900 | 1000 |
| Yabucoa | 2 | Caguas | 900 | 1000 |
| Palo Seco | 6 | Bayamon | 900 | 1000 |
| Costa Sur | 2 | Ponce Oe | 900 | 1000 |
| Aguirre | 2 | Ponce ES | 900 | 1000 |
| Vega Baja | 2 | Bayamon | 900 | 1000 |
| Jobos | 2 | | 900 | 1000 |

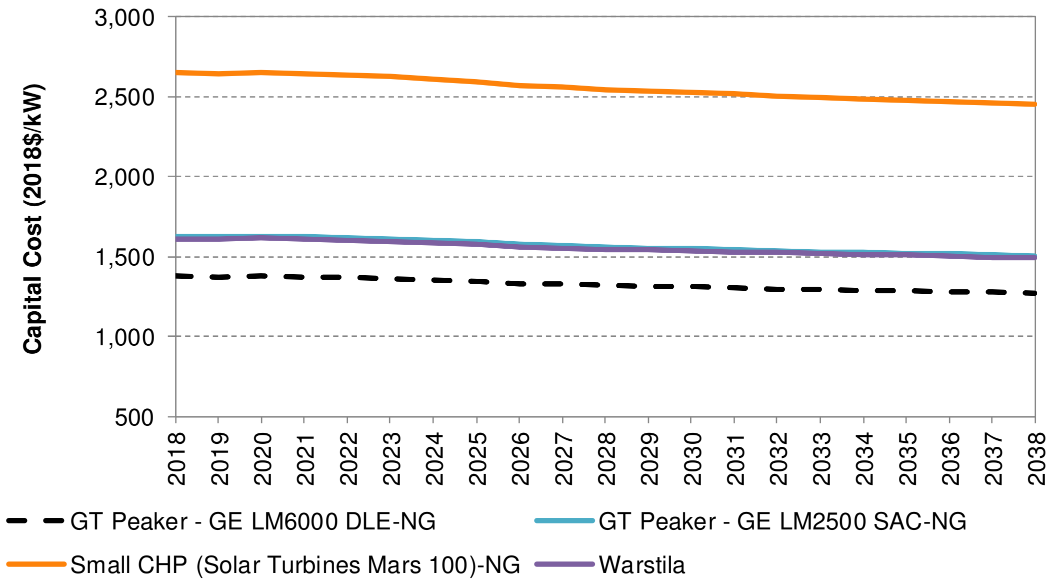
The capital cost curves below are derived based of the 2018 National Renewable Energy Laboratory (NREL) Annual Technology Baseline for the Gas CC/CT based on Annual Energy Outlook 2018. The costs curves can be used to estimate the capital costs for future units considering the deployment dates.

**Exhibit 6-15. Capital Cost Curve for Gas CCGT**




Source: Siemens, NREL 2018 ATB

**Exhibit 6-16. Capital Cost Curve for GT**




Source: Siemens, NREL 2018 ATB

### 6.2.3 Future Generation Resources Development Timeline

For addition of new resources, IRPs need to factor development time from the initial RFP to the Commercial Operation Date. Exhibit 6-17 shows the expected development timeframes for the representative technologies. In this exhibit, development includes the activities from RFP and bid evaluation to permitting and financing. The EPC is the actual engineering, procurement and construction to Commercial Operation.

**Exhibit 6-17. Development and Construction Durations**

| Representative New Resource Candidates | Capacity (MW) | Development Duration (Years) | EPC Duration (Years) |
|---|---|---|---|
| H Class CCGT (GE S107HA.01) (Duct Fired) | 449 | 2.5 | 3.0 |
| F Class CCGT (GE S107F.04) (Duct Fired) | 302 | 2.5 | 3.0 |
| F Class CCGT (GE S107F.05) (Duct Fired) | 369 | 2.5 | 3.0 |
| Medium CCGT (Hitachi H-100) (Duct Fired) | 144 | 2.5 | 2.5 |
| Small CCGT (GE LM6000 DLE) (Duct Fired) | 66 | 2.0 | 2.0 |
| Small CCGT (GE LM2500+ G4 SAC) (Duct Fired) | 47.7 | 2.0 | 2.0 |
| Small CCGT (GE LM2500 SAC) (Duct Fired) | 35 | 2.0 | 2.0 |
| Aero/Small GT Peaker (GE LM6000 DLE) | 41 | 1.5 | 1.5 |

| Representative New Resource Candidates | Capacity (MW) | Development Duration (Years) | EPC Duration (Years) |
|---|---|---|---|
| Aero/Small GT Peaker (GE LM2500 SAC) | 22 | 1.5 | 1.5 |
| Small CHP (Solar Turbines Mars 100) | 9 | 1.5 | 1.5 |
| RICE (Wartsila 18V50DF) | 16 | 1.5 | 1.5 |

Note: Capacity based on natural gas firing.

### 6.2.4 Levelized Cost of Energy (LCOE)

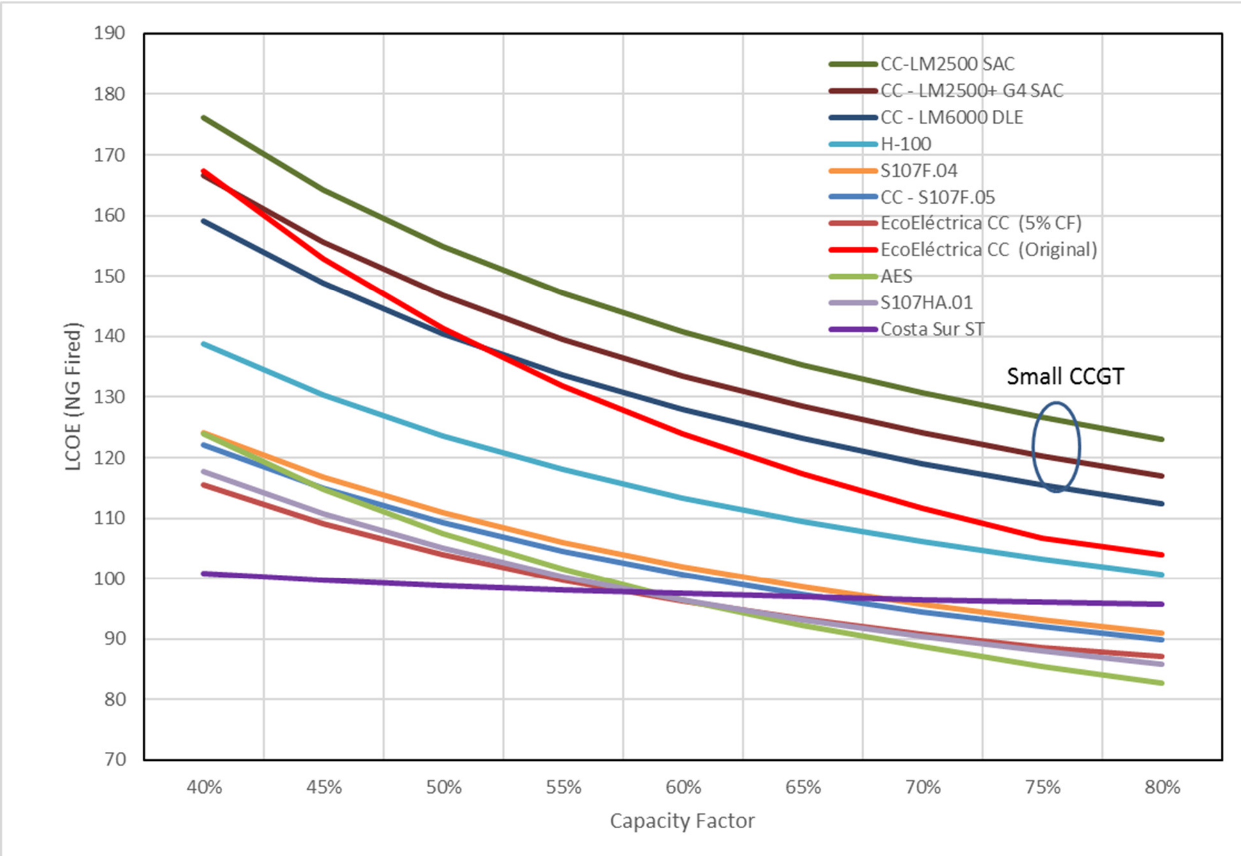
A high level LCOE was calculated on all new technologies to form a preliminary view of their respective costs for the IRP.

The LCOE was estimated using the heat rate at 100% rated unfired capacity and considering delivered diesel and new natural gas prices (including commodity, liquefaction, and shipping, but not regasification costs) at San Juan to calculate fuel costs. The regasification costs were determined considering a land-based LNG regasification terminal at San Juan with a pipeline to Palo Seco with max daily gas volume of 93.6 MMcf/day to support a total generation capacity of 650 MW. Siemens estimated that this regasification infrastructure adds a fixed cost of $116.5/kW-year to any potential new gas-fired generation resources at San Juan or Palo Seco accounting for fixed operating costs and return on capital at a WACC (weighted average cost of capital) of 8.5 percent and an economic life of 22 years. This same WACC was used to annualize the generation capital considering an asset economic life of 29 years for a large combined cycle plant and 20 years for the remaining technologies.

As a reference, Siemens also calculated the LCOE for Costa Sur 5 & 6 considering the O&M costs plus delivered gas. For AES, Siemens considered the forecasted cost of coal, O&M and capacity payments. For EcoEléctrica, Siemens considered the two fuel components reflected in the PPOA; for energy under 76% dispatch, and for the spot price energy produced above that level it was assumed to be equal to the delivered gas at San Juan. Siemens also factored in the EcoEléctrica O&M costs and capacity payments.

Exhibit 6-18 shows the LCOE of the large and medium CCGT with gas and a comparison with the estimated LCOE of Costa Sur 5&6, EcoEléctrica and AES. Exhibit 6-19 provides the numeric values of this LCOE. As can be observed below, depending on the dispatch (and the fuel price assumptions made), it is possible that EcoEléctrica could be economically retired as well as Costa Sur 5&6, considering that its replacement by a flexible CCGT will reduce the need for energy storage capacity. This result would change for the case where the EcoEléctrica contract is renegotiated, and the capacity payments are reduced.

**Exhibit 6-18. Large and Medium CCGT with Gas, Costa Sur 5&6, EcoEléctrica and AES**




Source: Siemens

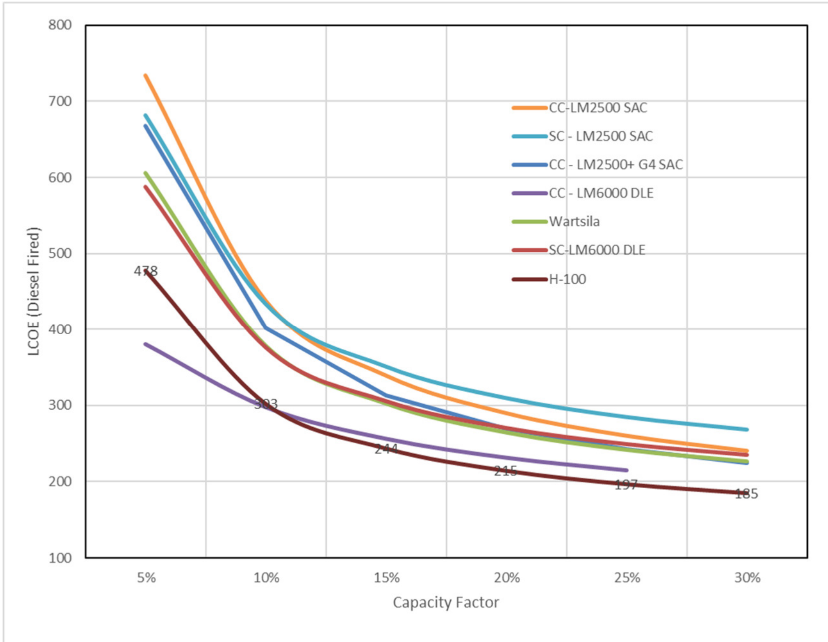
**Exhibit 6-19. LCOE for Large and Medium Combined Cycle units**

| Case Description | H Class CCGT | | F Class CCGT | | F Class CCGT | | Medium CCGT | |
|---|---|---|---|---|---|---|---|---|
| Manufacturer | GE | | GE | | GE | | MHPS | |
| Model | S107HA.01 | | CC - S107F.05 | | S107F.04 | | H-100 | |
| Type | CC 1x1 | | CC 1x1 | | CC 1x1 | | CC 1x1 | |
| Capacity MW | 449 | 438 | 369 | 361 | 302 | 296 | 144 | 141 |
| Fuel | NG | Diesel | NG | Diesel | NG | Diese | NG | Diesel |
| **Capacity Factor** | **LCOE (2018$/MWh)** | | | | | | | |
| 5% | 565 | 360 | 574 | 373 | 589 | 388 | 674 | 478 |
| 10% | 309 | 235 | 316 | 246 | 323 | 253 | 368 | 303 |
| 15% | 224 | 193 | 230 | 203 | 235 | 208 | 266 | 244 |
| 20% | 182 | 173 | 187 | 182 | 191 | 186 | 215 | 215 |
| 25% | 156 | 160 | 161 | 169 | 164 | 172 | 185 | 197 |
| 30% | 139 | 152 | 144 | 161 | 146 | 163 | 164 | 185 |
| 35% | 127 | 146 | 131 | 154 | 134 | 157 | 150 | 177 |
| 40% | 118 | 141 | 122 | 150 | 124 | 152 | 139 | 171 |
| 45% | 111 | 138 | 115 | 146 | 117 | 148 | 130 | 166 |
| 50% | 105 | 135 | 109 | 144 | 111 | 145 | 124 | 162 |
| 55% | 100 | 133 | 105 | 141 | 106 | 143 | 118 | 159 |
| 60% | 96 | 131 | 101 | 139 | 102 | 141 | 113 | 156 |
| 65% | 93 | 129 | 97 | 138 | 99 | 139 | 109 | 154 |
| 70% | 90 | 128 | 94 | 136 | 96 | 138 | 106 | 152 |
| 75% | 88 | 127 | 92 | 135 | 93 | 136 | 103 | 150 |
| 80% | 86 | 126 | 90 | 134 | 91 | 135 | 101 | 149 |
| 85% | 84 | 125 | 88 | 133 | 89 | 134 | 98 | 148 |
| 90% | 82 | 124 | 86 | 132 | 87 | 133 | 96 | 146 |

Source: Siemens

With respect of the small CCGT units, GT and the Wärtsilä RICE, Exhibit 6-20 below shows the LCOE cost converge near the expected capacity factor ranges, with perhaps the LM2500 being the least competitive. The LCOE is presented considering Diesel (LFO) as the likely fuel for these units. Exhibit 6-21 show the numeric values for the LCOE for the small CCGT units and Exhibit 6-22 for the CHP option. Siemens further notes in this exhibit that for applications where large amount of power are required, the H-100 Combined Cycle and the LM6000 Combined Cycle are competitive even at very small capacity factors.

## Exhibit 6-20. Small CCGT, Peakers (GT) and RICE with Diesel




Source: Siemens

## Exhibit 6-21. LCOE for Small Combined Cycle units and GT Aero Peakers

| Case Description | Aero or Small CCGT | | Aero or Small CCGT | | Aero or Small CCGT | | Aero SC/ Peaker | | Aero SC/ Peaker | |
|---|---|---|---|---|---|---|---|---|---|---|
| Manufacturer | GE | | GE | | GE | | GE | | GE | |
| Model | CC - LM6000 DLE | | CC - LM2500+ G4 SAC | | CC-LM2500 SAC | | SC-LM6000 DLE | | SC - LM2500 SAC | |
| Type | CC 1x1 | | CC 1x1 | | CC 1x1 | | SC | | SC | |
| | x` | 63 | 38 | 38 | 29 | 28 | 41 | 39 | 22 | 21 |
| Fuel | NG | Diesel | NG | Diesel | NG | Diesel | NG | Diesel | NG | Diesel |
| **Capacity Factor** | **LCOE (2018$/MWh)** | | | | | | | | | |
| 5% | 814 | 631 | 861 | 667 | 918 | 734 | 754 | 588 | 838 | 682 |
| 10% | 440 | 381 | 464 | 402 | 494 | 438 | 417 | 376 | 465 | 434 |
| 15% | 315 | 298 | 332 | 313 | 353 | 340 | 305 | 306 | 340 | 351 |
| 20% | 253 | 256 | 266 | 269 | 282 | 290 | 249 | 270 | 278 | 310 |
| 25% | 215 | 231 | 226 | 242 | 240 | 261 | 215 | 249 | 241 | 285 |
| 30% | 190 | 214 | 200 | 225 | 211 | 241 | 193 | 235 | 216 | 269 |
| 35% | 173 | 202 | 181 | 212 | 191 | 227 | 177 | 225 | 198 | 257 |
| 40% | 159 | 194 | 167 | 202 | 176 | 216 | 165 | 217 | 185 | 248 |
| 45% | 149 | 187 | 156 | 195 | 164 | 208 | 156 | 211 | 175 | 241 |
| 50% | 140 | 181 | 147 | 189 | 155 | 201 | 148 | 207 | 166 | 236 |
| 55% | 134 | 177 | 140 | 184 | 147 | 196 | 142 | 203 | 159 | 231 |
| 60% | 128 | 173 | 134 | 180 | 141 | 192 | 137 | 200 | 154 | 228 |
| 65% | 123 | 170 | 128 | 177 | 135 | 188 | 133 | 197 | 149 | 224 |
| 70% | 119 | 167 | 124 | 174 | 131 | 184 | 129 | 195 | 145 | 222 |
| 75% | 115 | 164 | 120 | 171 | 127 | 182 | 126 | 193 | 141 | 219 |
| 80% | 112 | 162 | 117 | 169 | 123 | 179 | 123 | 191 | 138 | 217 |
| 85% | 110 | 160 | 114 | 167 | 120 | 177 | 121 | 189 | 135 | 215 |
| 90% | 107 | 159 | 111 | 166 | 117 | 175 | 118 | 188 | 133 | 214 |

Source: Siemens

**Exhibit 6-22. LCOE for CHP and RICE Units**

| Case Description | CHP | | CHP (56% Heat Rate) | | RICE |
|---|---|---|---|---|---|
| Manufacturer | Solar Turbines | | Solar Turbines | | Wartsila |
| Model | Mars 100 | | Mars 100 | | Wartsila 18V50DF |
| Type | Cogen -- LP steam | | Cogen -- LP steam | | |
| Capacity MW | 9 | 9 | 9 | 9 | 16 |
| Fuel | NG | Diesel | NG | Diesel | Diesel |
| **Capacity** | **LCOE (2018$/MWh)** | | | | |
| 5% | 1124 | 962 | 1076 | 867 | 606 |
| 10% | 614 | 587 | 566 | 491 | 378 |
| 15% | 444 | 461 | 396 | 366 | 302 |
| 20% | 359 | 399 | 311 | 304 | 264 |
| 25% | 308 | 361 | 260 | 266 | 242 |
| 30% | 274 | 336 | 226 | 241 | 226 |
| 35% | 250 | 318 | 202 | 223 | 216 |
| 40% | 232 | 305 | 183 | 210 | 207 |
| 45% | 217 | 294 | 169 | 199 | 201 |
| 50% | 206 | 286 | 158 | 191 | 196 |
| 55% | 197 | 279 | 149 | 184 | 192 |
| 60% | 189 | 274 | 141 | 178 | 188 |
| 65% | 183 | 269 | 134 | 174 | 185 |
| 70% | 177 | 265 | 129 | 169 | 183 |
| 75% | 172 | 261 | 124 | 166 | 181 |
| 80% | 168 | 258 | 120 | 163 | 179 |
| 85% | 164 | 255 | 116 | 160 | 177 |
| 90% | 161 | 253 | 113 | 158 | 176 |

Source: Siemens

## 6.3 Solar Photovoltaic (PV) Projects

The IRP assumes utility scale solar for new builds of renewable resources. The cost estimates for utility scale solar PV projects are developed through the following steps: 1) establish baseline solar PV operating and overnight capital costs estimate; 2) evaluate interconnection and land costs specific to Puerto Rico; 3) assess construction and financing costs reflecting Puerto Rico specific assumptions; and 4) calculate Levelized Cost of Energy (LCOE) for solar PV in Puerto Rico.

### 6.3.1 Baseline Operating and Overnight Capital Costs

For step 1, the IRP assumes overnight capital costs and operating costs for utility-scale PV systems consistent with the recently published 2018 Annual Technology Baseline (ATB) by National Renewable Energy Laboratory (NREL) as shown in Exhibit 6-23. The PV system is representative of one-axis tracking systems with performance and pricing characteristics; this cost is somewhat higher than the cost of fixed tilt normally used in Puerto Rico, but it was maintained considering that in the territory additional costs may be incurred for hardening. The assumptions below do not account for a

1.3 DC-to-AC ratio, otherwise known as inverter loading ratio that is included when calculating the LCOE.

**Exhibit 6-23. U.S. Utility Scale Solar PV Costs Assumptions**

| NREL 2018 Annual Technology Baseline (ATB) Mid Case | | |
|---|---|---|
| Year | PV Overnight Capital Costs $2018/KWdc | Fixed Operating Costs $2018/kW-year (dc) |
| 2018 | 1,087 | 9.52 |
| 2019 | 1,046 | 9.11 |
| 2020 | 984 | 8.37 |
| 2021 | 933 | 7.80 |
| 2022 | 923 | 7.71 |
| 2023 | 912 | 7.63 |
| 2024 | 902 | 7.54 |
| 2025 | 891 | 7.46 |
| 2026 | 880 | 7.38 |
| 2027 | 870 | 7.29 |
| 2028 | 859 | 7.21 |
| 2029 | 849 | 7.12 |
| 2030 | 838 | 7.04 |
| 2031 | 831 | 6.98 |
| 2032 | 824 | 6.92 |
| 2033 | 817 | 6.86 |
| 2034 | 809 | 6.81 |
| 2035 | 802 | 6.75 |
| 2036 | 795 | 6.69 |
| 2037 | 788 | 6.63 |
| 2038 | 780 | 6.57 |
| 2039 | 773 | 6.52 |

| NREL 2018 Annual Technology Baseline (ATB) Low Case | | |
|---|---|---|
| Year | PV Overnight Capital Costs $2018/KWdc | Fixed Operating Costs $2018/kW-year (dc) |
| 2018 | 960 | 8.51 |
| 2019 | 912 | 8.04 |
| 2020 | 870 | 7.45 |
| 2021 | 833 | 7.00 |
| 2022 | 810 | 6.81 |
| 2023 | 786 | 6.62 |
| 2024 | 763 | 6.43 |
| 2025 | 739 | 6.24 |
| 2026 | 715 | 6.05 |
| 2027 | 692 | 5.87 |
| 2028 | 668 | 5.68 |
| 2029 | 645 | 5.49 |
| 2030 | 621 | 5.30 |
| 2031 | 611 | 5.22 |
| 2032 | 600 | 5.13 |
| 2033 | 590 | 5.05 |
| 2034 | 582 | 4.98 |
| 2035 | 565 | 4.85 |
| 2036 | 552 | 4.74 |
| 2037 | 538 | 4.64 |
| 2038 | 525 | 4.53 |
| 2039 | 512 | 4.43 |

Source: NREL 2018 ATB, converted to $2018. (https://atb.nrel.gov/electricity/data.html)

## 6.3.2 Interconnection Costs

The NREL benchmark includes the transformation to transmission voltage level (e.g. 115 kV) and a cost of $0.03/Wdc[30] for interconnection costs to the point of interconnection (POI) and a cost of $263,000 for the interconnecting lines (Gen-Ties) to the POI (based on a 30 MW plant). In the case of PREPA, these costs can change significantly, thus Siemens added the PREPA specific cost to its estimate and subtracted the corresponding NREL cost element. Exhibit 6-24 shows the interconnection costs assumed for a solar PV project that includes the expansion of an existing substation with one new bay for the solar PV project, the expansion of the control house, and 1 mile of interconnecting line. All unit costs shown were provided by PREPA.

[30] The NREL interconnection costs are subject to update upon receiving response from the NREL

**Exhibit 6-24. Interconnection Costs**

| **Interconnection Costs** | Unit | Value | Unit Price $/unit | Capital ($ 000) |
|---|---|---|---|---|
| Interconnecting Line (Gen-Tie) | Miles | 1 | 1,500,000 | 1,500 |
| Right of Way Costs (115 kV 50 ft wide) | m2 | 24,521 | 3 | 74 |
| New Bay for Interconnection | Each | 1 | 2,400,000 | 2,400 |
| Control House Extension | Each | 1 | 300,000 | 300 |
| Total Interconnection Cost | | | | 4,274 |
| Cost already included in NREL | | | | (1,433) |
| **Total Adjusted Interconnection Cost** | | | | **2,840** |

Note: The NREL interconnection costs are subject to update upon receiving response from the NREL

### 6.3.3 Land Costs

PV facilities require large stretches of land. NREL on its report "Land-Use Requirements for Solar Power Plants in the United States" indicates that for large projects (greater than 20 MW) the land use is approximately 7.5 acres per MWac for fixed tilt systems and approximately and 8.3 acres per MWac for one-axis tilt systems. These values are in the mid-range of project values ranging from 9 acres per MWac to 5 acres per MWac, based on Siemens projects experience.

Using NREL values, a 30 MW[31] project would require an area of 225 acres or 910,543 $m^2$. Using the land cost provided by PREPA the table below shows Siemens estimation of costs for a 30 MW project. Note that in this table, Siemens is subtracting the costs already included in NREL benchmark ($0.03/Wdc).

**Exhibit 6-25. Land Costs**

| **Land Costs (30 MW Solar)** | Unit | Value | Unit Price $/unit | Capital ($ 000) |
|---|---|---|---|---|
| Area for PV Project | m2 | 910,543 | 3 | 2,732 |
| Cost already included in NREL | | | | 1,170 |
| **Total land cost** | | | | **1,562** |

### 6.3.4 Weighted Average Cost of Capital (WACC)

In the context of developing a consensus assumption of WACC among key stakeholders, Siemens acknowledges a few important factors impacting both the cost and availability of capital. With $9 billion debt outstanding, PREPA currently has no access to bond market and bank financing. In addition, recent Act 120-2018 authorized PREPA to sell its generating assets to potential private buyers.

Based on discussions with stakeholders, Siemens considers future builds to be financed by third parties, and consider that PREPA obtain financial backing to contract as a credit-worthy counterparty, if and as needed. Exhibit 6-26 shows the component assumptions deriving a nominal weighted average cost of capital of 8.50%.

[31] 30 MW was selected as a representative size of a utility scale project.

**Exhibit 6-26. Weighted Average Cost of Capital Assumptions**

| **Cost of Equity** | |
|---|---|
| Asset Beta | 0.70 |
| Income Tax Rate | 39.00% |
| Debt to Equity Ratio | 0.90 |
| Equity Beta | 1.08 |
| | |
| Risk-Free Rate | 2.95% |
| Equity Risk Premium | 5.50% |
| Company Specific Risk Premium | 4.00% |
| Cost of Equity | 12.91% |
| | |
| **Cost of Debt** | |
| Cost of Debt, Pre-tax | 5.00% |
| Tax Rate | 32.0% |
| Cost of Debt, After-tax | 3.40% |
| | |
| **Weighted Average Cost of Capital** | |
| After-tax Cost of Debt | 3.40% |
| Percent Debt | 47% |
| Cost of Equity | 12.91% |
| Percent Equity | 53% |
| **WACC** | **8.50%** |

Note: The corporate income tax rate is assumed based on a base rate of 20%, plus a graduated surcharge ranging from 5% to 19%[32].

### 6.3.5 Investment Tax Credit (ITC)

The solar Investment Tax Credit (ITC) is one of the most important federal policy mechanisms to support the deployment of solar energy in the United States. Consistent with the current policy, the IRP assumes the following: solar facilities that commence construction prior to January 1, 2020 will qualify for the full amount of the ITC (i.e., 30 percent); solar facilities that commence construction during 2020, the amount of the ITC will be reduced from 30 percent to 26 percent; solar facilities that commence construction during 2021, the amount of the ITC will be reduced from 26 percent to 22 percent; and solar facilities that commence construction in 2022 or thereafter, the amount of the ITC will drop to 10 percent.

### 6.3.6 Project Development and Construction Time

Based on discussions with PREPA and advisors, the IRP assumes an accelerated timeline for solar projects, assuming 12 months for the development period (request for proposal, bid evaluation, permitting, and financing) and 12 months for construction.

[32] Deloitte International Tax Puerto Rico Highlights 2018

This time line assumes fast track permitting, proper submittal of project design for evaluation by PREPA (particularly for mathematical model evaluation, and control, protection and telecommunications design), as well as securing the land for the interconnection line and any additional land acquisition required for interconnection at PREPA's facilities that will be secured by project company. Those projects that require new-build PREPA interconnection facilities (sectionalizer or transmission centers) could require longer development and construction times.

Additionally, there are limits on the amount of annual installations that can effectively be carried out in parallel. This changes as a function of the scenarios discussed earlier and are as presented below.

**Exhibit 6-27: Solar PV and BESS Annual Installation Constraints for Core Scenarios 1, 4, 5, and 6**

| | 2019 | 2020 | 2021 | 2022-2038 |
|---|---|---|---|---|
| Solar PV Annual Installation Limit (MW) | 0 | 300 | 300 | 600 |
| BESS Annual Installation Limit (MW) | 60-180 | 300 | 300 | 600 |

**Exhibit 6-28: Solar PV and BESS Annual Installation Constraints for Sensitivity 1 (low cost of renewable)**

| | 2019 | 2020 | 2021 | 2022-2038 |
|---|---|---|---|---|
| Solar PV Annual Installation Limit (MW) | 0 | 300 | 1200 | 1200 |
| BESS Annual Installation Limit (MW) | 60-180 | 300 | 1200 | 1200 |

For modeling the ESM scenario, the following limits were considered:

**Exhibit 6-29: Solar PV and BESS Annual Installation Constraints for ESM Scenario**

**Photovoltaic resources (PV)**

| Year of Completion | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|
| Annual Increment(MW) | 240 | 480 | 480 | 300 |
| Cumulative Total (MW) | 240 | 720 | 1200 | 1500 |

**Battery Energy Storage Systems (BESS)**

| Year of Completion | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|
| Annual Increment(MW) | 20 | 100 | 160 | 160 | 160 | 150 |
| Cumulative Total (MW) | 20 | 120 | 280 | 440 | 600 | 750 |

### 6.3.7 Levelized Cost of Energy (LCOE)

For the IRP modeling, the levelized cost of energy (LCOE) is calculated as the net present value of the unit-cost of energy over the lifetime of the solar PV asset. The LCOE is then used as a proxy for the average price that the solar PV project could break even over its lifetime. Exhibit 6-30 shows the LCOE of solar PV under Mid case and Low case. Exhibit 6-31 shows the other assumptions used in deriving the LCOE. Exhibit 6-32 shows graphically the cost trend, and Exhibit 6-33 and Exhibit 6-34 show the LCOE calculation for the base case and low case separately.

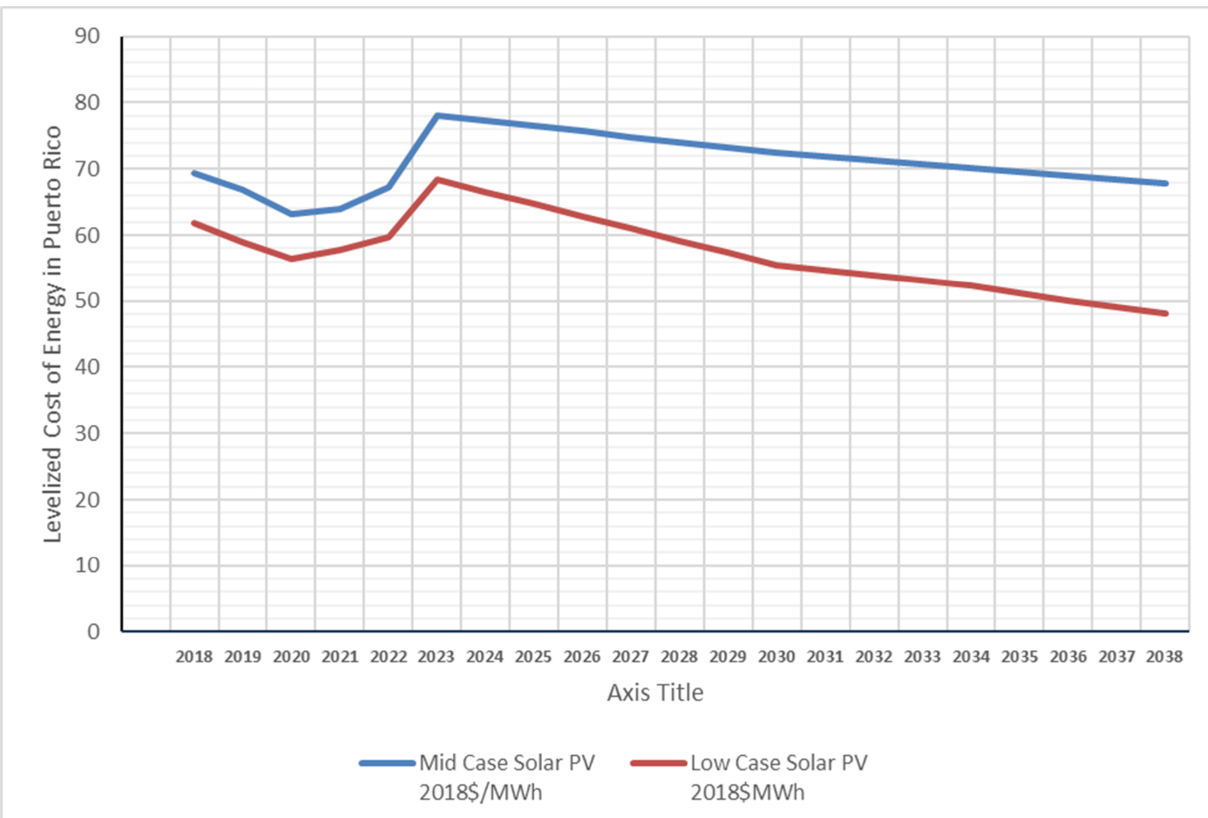
**Exhibit 6-30. Levelized Cost of Energy (LCOE) of Solar PV**

| Levelized Cost of Energy in Puerto Rico | | |
|---|---|---|
| Commercial On Line (COD) Year | Mid Case Solar PV 2018$/MWh | Low Case Solar PV 2018$MWh |
| 2018 | 69 | 62 |
| 2019 | 67 | 59 |
| 2020 | 63 | 56 |
| 2021 | 64 | 58 |
| 2022 | 67 | 60 |
| 2023 | 78 | 68 |
| 2024 | 77 | 67 |
| 2025 | 76 | 65 |
| 2026 | 76 | 63 |
| 2027 | 75 | 61 |
| 2028 | 74 | 59 |
| 2029 | 73 | 57 |
| 2030 | 72 | 55 |
| 2031 | 72 | 55 |
| 2032 | 71 | 54 |
| 2033 | 71 | 53 |
| 2034 | 70 | 52 |
| 2035 | 70 | 51 |
| 2036 | 69 | 50 |
| 2037 | 68 | 49 |
| 2038 | 68 | 48 |

**Exhibit 6-31. Levelized Cost of Energy (LCOE) Assumptions**

| Item | Unit | Assumption |
|---|---|---|
| DC / AC Conversion | X | 1.3 |
| Size | MW | 30 |
| Solar Capacity Factor | % | 22% |
| Wind Capacity Factor | % | 25% |
| Puerto Rico Solar Overnight Cost Adder | % | 16% |
| Solar Construction Finance Factor | % | 101.5% |
| Wind Construction Finance Factor | % | 102.5% |
| Small Scale Adder | % | 0% |
| Solar PV /Wind Capital Recovery Period | year | 30 |
| Battery Storage Capital Recovery Period | year | 20 |
| $2016 to $2018 Conversion | X | 1.035 |

**Exhibit 6-32. Photovoltaic Levelized Cost of Energy (LCOE) 2018$/MWh**



## Exhibit 6-33. Levelized Cost of Energy (LCOE) of Solar PV – Base Case

| Commercial on line year | | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | *2030* | *2035* | *2038* |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Construction Start Year | | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | *2029* | *2034* | *2037* |
| **Capital and Operating Costs** | | | | | | | | | | | |
| Overnight Cost, US National, 100 MW | $2018/Wdc | 1.05 | 0.98 | 0.93 | 0.92 | 0.91 | 0.90 | 0.89 | 0.84 | 0.80 | 0.78 |
| AC/DC Conversion | X | 1.30 | 1.30 | 1.30 | 1.30 | 1.30 | 1.30 | 1.30 | 1.30 | 1.30 | 1.30 |
| Puerto Rico Adder | % | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% |
| Overnight Cost, Puerto Rico, 100 MW | $2018/Wac | 1.58 | 1.48 | 1.41 | 1.39 | 1.38 | 1.36 | 1.34 | 1.26 | 1.21 | 1.18 |
| IDC Cost Adder | % | 1.5% | 1.5% | 1.5% | 1.5% | 1.5% | 1.5% | 1.5% | 1.5% | 1.5% | 1.5% |
| All-In Cost, Puerto Rico, 100 MW, $/Wac | $2018/Wac | 1.60 | 1.51 | 1.43 | 1.41 | 1.40 | 1.38 | 1.36 | 1.28 | 1.23 | 1.19 |
| Small Scale Adder (30 MW) | % | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Base Cost, Puerto Rico, 30 MW | $2018/Wac | **1.60** | **1.51** | **1.43** | **1.41** | **1.40** | **1.38** | **1.36** | **1.28** | **1.23** | **1.19** |
| Fixed O&M | $2018/kW-yr | 11.85 | 10.88 | 10.14 | 10.03 | 9.92 | 9.81 | 9.70 | 9.15 | 8.77 | 8.55 |
| | | | | | | | | | | | |
| **30 MW Solar PV Project Parameters** | | | | | | | | | | | |
| Capacity | MW | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 |
| Capacity Factor | % | 22% | 22% | 22% | 22% | 22% | 22% | 22% | 22% | 22% | 22% |
| Energy Produced | MWh | 57,816 | 57,816 | 57,816 | 57,816 | 57,816 | 57,816 | 57,816 | 57,816 | 57,816 | 57,816 |
| | | | | | | | | | | | |
| Base Capital PV System | $2018 thousand | 48,033 | 45,207 | 42,853 | 42,369 | 41,885 | 41,401 | 40,917 | 38,498 | 36,835 | 35,837 |
| Interconnection Costs | $2018 thousand | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 |
| Land Costs | $2018 thousand | 1,562 | 1,562 | 1,562 | 1,562 | 1,562 | 1,562 | 1,562 | 1,562 | 1,562 | 1,562 |
| Total PV System Capital Costs | $2018 thousand | 52,435 | 49,609 | 47,255 | 46,771 | 46,287 | 45,803 | 45,319 | 42,900 | 41,237 | 40,239 |
| | | | | | | | | | | | |
| ITC | % | 30% | 30% | 26% | 22% | 10% | 10% | 10% | 10% | 10% | 10% |
| Income Tax | % | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% |
| Capital Recovery Factor | % | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% |
| Project Financing Factor | % | 71% | 71% | 76% | 81% | 97% | 97% | 97% | 97% | 97% | 97% |
| Construction Financing Factor | % | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 |
| | | | | | | | | | | | |
| **Annualized PV Capital Costs** | $2018 thousand | **3,510** | **3,321** | **3,392** | **3,584** | **4,220** | **4,176** | **4,132** | **3,911** | **3,759** | **3,668** |
| Fixed O&M | $2018 thousand | 355 | 327 | 304 | 301 | 297 | 294 | 291 | 274 | 263 | 256 |
| **Total Base PV System Cost** | $2018 thousand | **3,866** | **3,648** | **3,697** | **3,885** | **4,517** | **4,470** | **4,422** | **4,186** | **4,023** | **3,925** |
| **Levelized Cost of Energy (PV Base)** | $2018/MWh | **67** | **63** | **64** | **67** | **78** | **77** | **76** | **72** | **70** | **68** |

## Exhibit 6-34. Levelized Cost of Energy (LCOE) of Solar PV – Low Case]

| Commercial on line year | | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 | 2038 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Construction Start Year | | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2029 | 2034 | 2037 |
| **Capital and Operating Costs** | | | | | | | | | | | |
| Overnight Cost, US National, 100 MW | $2018/Wdc | 0.91 | 0.87 | 0.83 | 0.81 | 0.79 | 0.76 | 0.74 | 0.62 | 0.56 | 0.53 |
| AC/DC Conversion | X | 1.30 | 1.30 | 1.30 | 1.30 | 1.30 | 1.30 | 1.30 | 1.30 | 1.30 | 1.30 |
| Puerto Rico Adder | % | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% |
| Overnight Cost, Puerto Rico, 100 MW | $2018/Wac | 1.38 | 1.31 | 1.26 | 1.22 | 1.19 | 1.15 | 1.11 | 0.94 | 0.85 | 0.79 |
| IDC Cost Adder | % | 1.5% | 1.5% | 1.5% | 1.5% | 1.5% | 1.5% | 1.5% | 1.5% | 1.5% | 1.5% |
| All-In Cost, Puerto Rico, 100 MW, $/Wac | $2018/Wac | 1.40 | 1.33 | 1.28 | 1.24 | 1.20 | 1.17 | 1.13 | 0.95 | 0.86 | 0.80 |
| Small Scale Adder (30 MW) | % | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Base Cost, Puerto Rico, 30 MW | $2018/Wac | **1.40** | **1.33** | **1.28** | **1.24** | **1.20** | **1.17** | **1.13** | **0.95** | **0.86** | **0.80** |
| Fixed O&M | $2018/kW-yr | 10.45 | 9.69 | 9.10 | 8.85 | 8.61 | 8.36 | 8.12 | 6.89 | 6.30 | 5.89 |
| | | | | | | | | | | | |
| **30 MW Solar PV Project Parameters** | | | | | | | | | | | |
| Capacity | MW | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 |
| Capacity Factor | % | 22% | 22% | 22% | 22% | 22% | 22% | 22% | 22% | 22% | 22% |
| Energy Produced | MWh | 57,816 | 57,816 | 57,816 | 57,816 | 57,816 | 57,816 | 57,816 | 57,816 | 57,816 | 57,816 |
| | | | | | | | | | | | |
| Base Capital PV System | $2018 thousand | 41,885 | 39,933 | 38,273 | 37,189 | 36,105 | 35,021 | 33,937 | 28,517 | 25,935 | 24,116 |
| Interconnection Costs | $2018 thousand | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 |
| Land Costs | $2018 thousand | 1,562 | 1,562 | 1,562 | 1,562 | 1,562 | 1,562 | 1,562 | 1,562 | 1,562 | 1,562 |
| Total PV System Capital Costs | $2018 thousand | 46,287 | 44,335 | 42,675 | 41,591 | 40,507 | 39,423 | 38,339 | 32,919 | 30,337 | 28,518 |
| | | | | | | | | | | | |
| ITC | % | 30% | 30% | 26% | 22% | 10% | 10% | 10% | 10% | 10% | 10% |
| Income Tax | % | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% |
| Capital Recovery Factor | % | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% |
| Project Financing Factor | % | 71% | 71% | 76% | 81% | 97% | 97% | 97% | 97% | 97% | 97% |
| Construction Financing Factor | % | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 |
| | | | | | | | | | | | |
| **Annualized PV Capital Costs** | $2018 thousand | **3,099** | **2,968** | **3,064** | **3,187** | **3,693** | **3,594** | **3,495** | **3,001** | **2,766** | **2,600** |
| Fixed O&M | $2018 thousand | 314 | 291 | 273 | 266 | 258 | 251 | 243 | 207 | 189 | 177 |
| **Total Base PV System Cost** | $2018 thousand | **3,412** | **3,259** | **3,337** | **3,453** | **3,951** | **3,845** | **3,739** | **3,208** | **2,955** | **2,777** |
| **Levelized Cost of Energy (PV Base)** | $2018/MWh | **59** | **56** | **58** | **60** | **68** | **67** | **65** | **55** | **51** | **48** |

### 6.3.8 Minimum Technical Requirements (MTR)

Renewable energy projects in Puerto Rico must comply with minimum technical requirements (MTR) to allow for their integration into the island's grid. In addition to the frequency ride through, voltage ride through and voltage regulation requirements, the MTR require the renewable generation to contribute to frequency response and most importantly limits its ramps to 10% of the project's Contractual Capacity per minute for both increase and decreases in production. This last requirement is subject to the limitations of the Battery Energy Storage System (BESS) with a Nominal Storage Capacity (NSC) equal to 30% of the Contractual Capacity and an Effective Storage Capacity (ESC) of 45% of the Contractual Capacity, deliverable for up to 1 minute. The ramp control poses the highest demands of active power and energy on the BESS and defines its size and cost.

The minimum energy requirements for ramp control could be assessed considering a situation where a project is delivering 100% of its capacity and due to a rapid cloud cover the output drops to practically zero. In this case the requirement becomes the Effective Storage Capacity (ESC) for one minute and then the Nominal Storage Capacity (NSC) for the balance of the time until the output is taken down to zero. However, from a practical perspective, an energy output equal to 10 min x 30% Project Capacity, would cover this requirement and leave some margin.

However, in the IRP Siemens expects that important levels of BESS will be installed in the system with the dual purpose of providing frequency regulation and shifting energy from day peak to night peak. Thus, modelling the frequency regulation and ramp rate control related MTRs in the IRP including the requirement for storage may result in inefficiencies particularly considering that: a) the investments in the balance of system (BOS) that includes the Power Conversion System (PCS) are similar regardless the energy storage is 10 minutes or 4 hours, making the second much more competitive and b) linking the renewable additions with a BESS may result in investments beyond the actual requirements for the system. Therefore, in the context of this IRP, the solar PV projects and the storage projects are considered separately with the consideration that, during the Request for Proposals (RFPs) to be issued during the implementation phase for solar PV projects, the required component of storage for its integration shall be added, with the flexibility for bidders to bid on one or both components.

PREPA should not commission neither allow the interconnection of PV solar or wind projects to the grid until the required corresponding energy storage component be commissioned and interconnected in full compliance with the energy storage technical requirements. It is also very important to emphasize that the solar PV projects shall still comply with the MTRs related with frequency ride through, voltage ride through, reactive power capability and voltage regulation in addition to their full compliance with the frequency regulation and frequency response requirements to be met by either separate or integrated energy storage. This approach is expected to foster competition and innovation while at the same time ensuring that the required regulation and energy shifting will be available for the PV integration before its interconnection.

## 6.4 Battery Storage

The goal of moving toward a low carbon future is leading to a proliferation of utility-scale solar PV and wind generation, and growing levels of distributed energy resources (DER) behind the meter. These developments are challenging the historical centralized paradigm for how a utility should design, build and manage an electricity system. Without the proper foundation of utility-integrated energy storage and software controls, renewable energy resources could face technical and operational challenges and curtailment of highly valued carbon-free electricity could be required in order for the utility to maintain system stability and reliability.

Energy storage technologies can prove valuable to utilities in managing such change as these technologies have the ability to decouple energy supply and demand, and thus provide a valuable resource to system operators. Energy storage could serve as generation or load and to produce or absorb both real and reactive power. Currently, Li-ion batteries are the most relevant battery technology with wide applications in power electronics, electric vehicles (EVs), and stationary storage (grid-scale).

### 6.4.1 Installed Costs and Applications

While energy storage costs and performance data are global in nature, the results presented here are most representative of the current U.S. energy storage market. The key individual costs making up the total energy storage system costs are detailed below:

**Capital costs:** The capital costs are for the entirety of the Battery Energy Storage System (BESS), which comprises the battery cell, the Power Conversion System (PCS) costs, and the related EPC costs. The battery energy storage system costs include the storage module (SM) and the balance of system (BOS) costs.

**Augmentation costs**: Augmentation costs represent the additional BESS equipment needed to maintain the usable energy capability to cycle the unit according to the usage profile in the particular use case, for the life of the system. Additional equipment is required in the following circumstances: (1) if the particular unit charges or discharges to a level less than its rated energy capacity (kWh) per cycle; (2) if the battery chemistry does not have the cycle-life needed to support the entire operating life of the use case; or (3) if the energy rating (kWh) of the battery chemistry degrades due to usage and can no longer support the intended application. This time-series of varying costs is then converted into a level charge over the life of the system to provide greater clarity for project developers.

**Operating costs:** These include the O&M costs, charging costs, and costs of extended warranties for the major equipment.

**Other costs:** These include financing costs (debt service payments), taxes paid, costs of meeting local and regional regulatory requirements, and warranty costs.

The costs of energy storage systems are based on specific selected grid applications and the power rating and usage duration assumptions are given below:

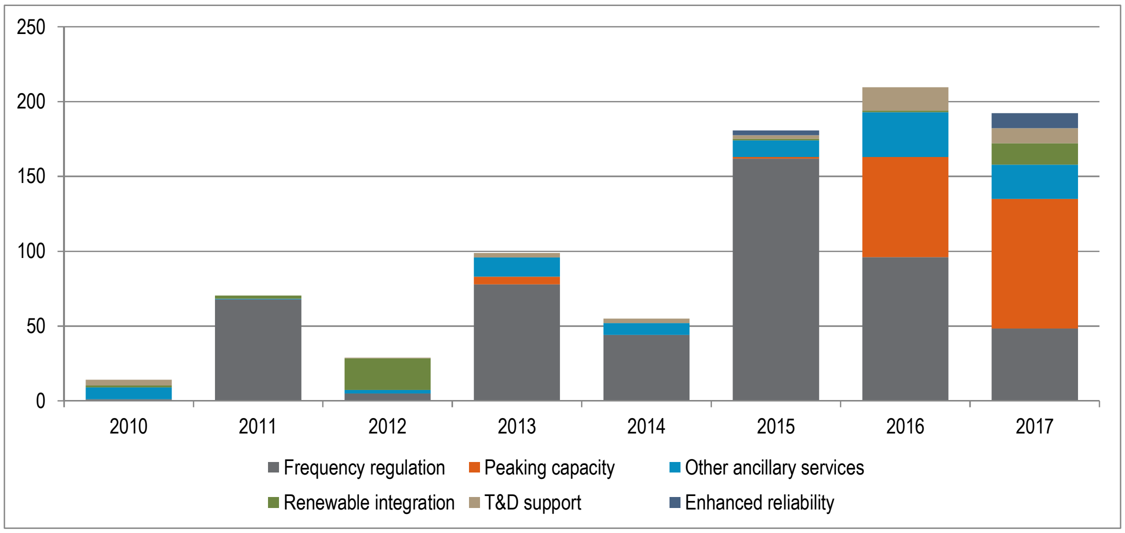
**Peaker replacement:** Large-scale energy storage system designed to replace peaking gas turbine facilities; brought online quickly to meet rapidly increasing demand for power at peak; can be quickly taken offline as power demand diminishes.

**Distribution:** Energy storage system designed to defer distribution upgrades, typically placed at substations or distribution feeder controlled by utilities to provide flexible peaking capacity, while also mitigating stability problems.

**Microgrid:** Energy storage system designed to support small power systems that can “island” or otherwise disconnect from the broader power grid (e.g., military bases, universities, etc.), to provide energy shifting, ramping support to enhance system stability, and increase reliability of service (emphasis is on short-term power output vs. load shifting, etc.).

While the majority of installed capacity provides frequency regulation, recent projects have targeted alternative applications including peaking capacity, renewable integration, and peak shaving. Exhibit 6-35 shows the primary application for installed storage capacity in recent history. The primary application is defined as the service that motivated the project, generally the highest-value or most profitable service. The category "other ancillary services" includes voltage support, black start, and operating reserves; and the category "renewable integration" is primarily energy shifting.

**Exhibit 6-35. U.S Installed Capacity (MW) by Primary Application**




Source: Siemens, IHS Markit

## 6.4.2 Future Cost Trends

Battery costs ($/kWh) can be lowered either by reducing the cost of the battery modules and balance of system (reducing $) or by improving the battery performances (increasing kWh) or by a combination of the two approaches.

Cost of batteries can be further reduced relative to where they are today by focusing on the battery modules and battery parts. However, it should be noted that extracting further cost reductions for the balance of system is going to prove increasingly difficult as the battery parts and materials become increasingly commoditized. The following options can be pursued to reduce battery cost:

- Using cheaper materials to build battery parts e.g. electrodes, electrolytes, separators, etc.
- Improving the supply chain and making the manufacturing processes for battery modules more cost effective
- Increasing the scale of manufacturing to spread the capital and fixed O&M costs over a very large number of modules produced

Battery performance can be further improved relative to where it is today, and this needs to be accomplished while keeping the costs comparable to today's technologies. The following avenues are being pursued to improve battery performance:

- Technological improvements, advances or breakthroughs, that lead to better performance, (e.g., cycle life, higher safety, more environmentally friendly, higher energy density, increasing voltage, and higher power density);
- Using better, more stable materials to build battery parts, (e.g., electrodes, electrolytes, and separators) that are able to deliver the better performance listed above;
- Using more effective chemistries, formulations, or crystal structures that overcome some of the limitations of today's technologies; and
- Using more stable solid electrolytes that enable higher voltages, reduce flammability, and make pure metal (e.g., lithium) anodes safer.

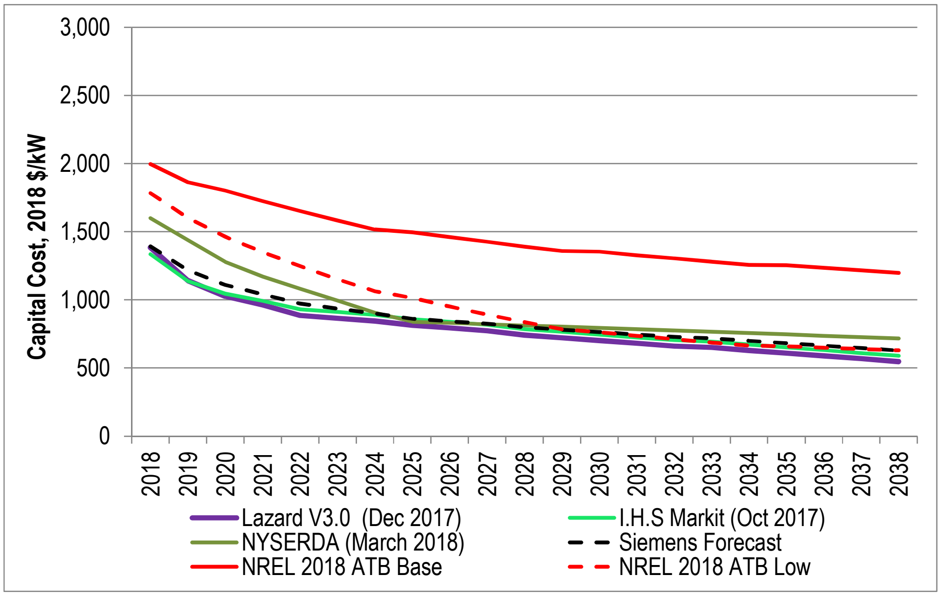
### 6.4.3 Li-ion Battery System Price Forecast

Li-ion batteries are, and are expected to remain, the mainstream technology for electrochemical energy storage. The support this technology has gathered at both the policy and industrial level is strong enough to keep it going for years to come. Multi-billion-dollar investments are already in place and a quiet arms race is in place to take the place of established Japanese and Korean battery companies, with the biggest threat being from China. Though medium-term shortages of raw materials such as cobalt may increase this portion of the cost somewhat, the larger declines driven by increased scale of production and intense worldwide competition, is likely to drive down the prices overall. As both the stationary energy storage and electric vehicle volumes begin to increase, new low-cost manufacturing facilities will continue to be built, particularly in China, which is expected to help prices continue to fall, albeit at a more temperate rate (~ 10–20% per year) through 2022. Beyond 2022, as economies of scale are maximized and technology improvements slow, battery prices are expected to approach the bottom and stabilize, limiting the decline to less than 5% a year.

Exhibit 6-37 and

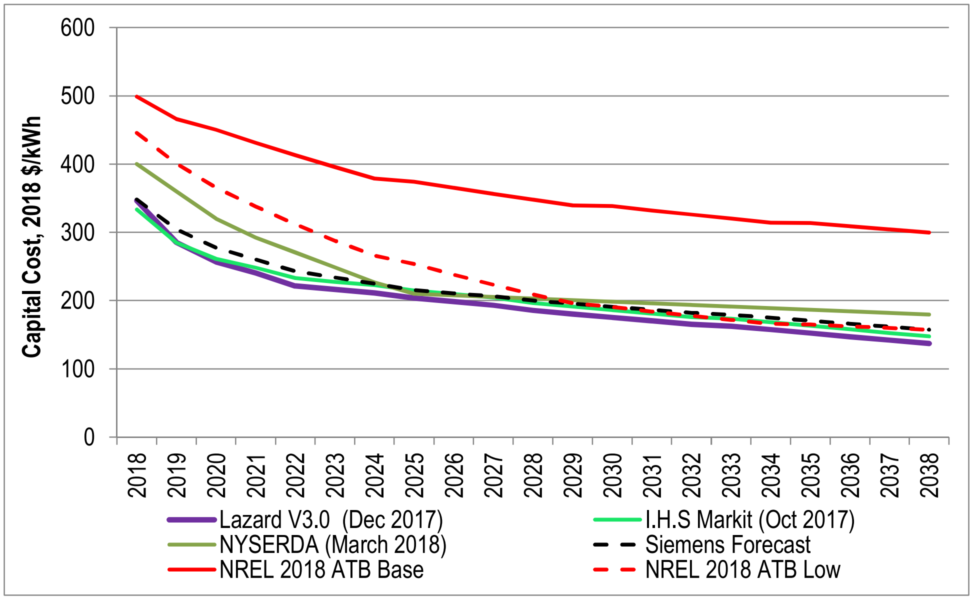
Exhibit 6-37 represent Siemens view of 4-hour 1 MW Li-Ion battery system price forecasts, in $/kW and $/kWh, respectively, in comparison with multiple other forecasts.

**Exhibit 6-36-. 4-hour Li-ion Battery System Capital Cost Forecasts**




Source: Siemens, IHS, Lazard, NYSERDA, NREL

**Exhibit 6-37. 4-hour Li-ion Battery System Capital Cost Forecasts**




Note: The capital cost ($/kW) is converted to LCOE ($/kWh) based on the 4-hour cycle of the battery storage.

Source: Siemens, IHS, Lazard, NYSERDA, NREL

Exhibit 6-38 and Exhibit 6-39 present the capital and operating costs assumptions of 2-hour, 4-hour and 6-hour storage in the base case and low case, respectively.

### Exhibit 6-38. Li-Ion Battery System Capital Cost and Operating Cost Assumptions – Base Case

| Construction Year | All-in Capital Costs | | | Operating Costs | |
|---|---|---|---|---|---|
| | 4-hour Li-ion Battery Storage 2018$/KW | 2-hour Li-ion Battery Storage 2018$/KW | 6-hour Li-ion Battery Storage 2018$/KW | Fixed Operating Costs 2018$/kW-year | Variable Operating Costs 2018$/MWh |
| 2018 | 1,392 | 832 | 1,953 | 9.09 | 2.67 |
| 2019 | 1,218 | 734 | 1,703 | 8.96 | 2.60 |
| 2020 | 1,110 | 674 | 1,546 | 8.95 | 2.58 |
| 2021 | 1,041 | 635 | 1,447 | 8.81 | 2.51 |
| 2022 | 972 | 596 | 1,349 | 8.67 | 2.43 |
| 2023 | 936 | 576 | 1,296 | 8.54 | 2.36 |
| 2024 | 899 | 556 | 1,243 | 8.41 | 2.29 |
| 2025 | 861 | 534 | 1,188 | 8.40 | 2.28 |
| 2026 | 843 | 523 | 1,163 | 8.26 | 2.20 |
| 2027 | 825 | 512 | 1,138 | 8.12 | 2.13 |
| 2028 | 800 | 496 | 1,104 | 7.99 | 2.06 |
| 2029 | 782 | 485 | 1,079 | 7.86 | 1.99 |
| 2030 | 764 | 474 | 1,054 | 7.85 | 1.97 |
| 2031 | 746 | 462 | 1,031 | 7.71 | 1.90 |
| 2032 | 728 | 450 | 1,007 | 7.57 | 1.82 |
| 2033 | 717 | 443 | 992 | 7.44 | 1.75 |
| 2034 | 700 | 431 | 969 | 7.31 | 1.69 |
| 2035 | 682 | 419 | 945 | 7.30 | 1.67 |
| 2036 | 664 | 407 | 922 | 7.19 | 1.64 |
| 2037 | 647 | 395 | 898 | 7.08 | 1.62 |
| 2038 | 629 | 383 | 875 | 6.97 | 1.59 |

Source: Siemens, NREL

### Exhibit 6-39. Li-Ion Battery System Capital Cost and Operating Cost Assumptions – Low Case

| Construction Year | All-in Capital Costs | | | Operating Costs | |
|---|---|---|---|---|---|
| | 4-hour Li-ion Battery Storage 2018$/KW | 2-hour Li-ion Battery Storage 2018$/KW | 6-hour Li-ion Battery Storage 2018$/KW | Fixed Operating Costs 2018$/kW-year | Variable Operating Costs 2018$/MWh |
| 2018 | 1,236 | 756 | 1,716 | 8.52 | 2.55 |
| 2019 | 1,047 | 651 | 1,443 | 8.22 | 2.45 |
| 2020 | 931 | 588 | 1,275 | 8.15 | 2.42 |
| 2021 | 857 | 549 | 1,165 | 7.81 | 2.31 |
| 2022 | 779 | 506 | 1,053 | 7.49 | 2.19 |
| 2023 | 743 | 488 | 997 | 7.18 | 2.09 |
| 2024 | 701 | 467 | 935 | 6.88 | 1.99 |
| 2025 | 664 | 448 | 880 | 6.80 | 1.95 |
| 2026 | 643 | 438 | 848 | 6.46 | 1.84 |
| 2027 | 623 | 428 | 818 | 6.14 | 1.73 |
| 2028 | 594 | 411 | 777 | 5.84 | 1.62 |
| 2029 | 573 | 400 | 746 | 5.55 | 1.53 |
| 2030 | 553 | 389 | 717 | 5.45 | 1.49 |
| 2031 | 536 | 375 | 696 | 5.11 | 1.37 |
| 2032 | 513 | 358 | 668 | 4.80 | 1.26 |
| 2033 | 497 | 345 | 650 | 4.50 | 1.16 |
| 2034 | 483 | 334 | 633 | 4.22 | 1.07 |
| 2035 | 465 | 319 | 610 | 4.10 | 1.02 |
| 2036 | 450 | 307 | 593 | 4.04 | 1.00 |
| 2037 | 437 | 296 | 578 | 3.98 | 0.99 |
| 2038 | 418 | 280 | 555 | 3.92 | 0.97 |

Source: Siemens, NREL

## 6.5 Wind Projects

As per the order by the Puerto Rico Energy Bureau (PREB)[33], wind resources are evaluated to in the economic competition with all other options, including fossil and other renewables. The cost estimates for utility scale wind projects were developed with the following steps: 1) establish baseline onshore wind projects operating and overnight capital costs estimate; 2) evaluate interconnection costs specific to Puerto Rico; 3) assess construction and financing costs reflecting Puerto Rico specific assumptions; and 4) calculate Levelized Cost of Energy (LCOE) for wind projects in Puerto Rico.

### 6.5.1 Baseline Operating and Overnight Capital Costs

For step 1, the IRP assumes overnight capital costs and operating costs for onshore wind projects consistent with the NREL 2018 ATB as shown in Exhibit 6-40.

**Exhibit 6-40. U.S. Utility Scale Wind Projects Costs Assumptions**

| NREL 2018 Annual Technology Baseline (ATB) Mid Case | | | NREL 2018 Annual Technology Baseline (ATB) Low Case | | |
|---|---|---|---|---|---|
| Year | Onshore Wind Overnight Capital Costs 2018$/KW | Fixed Operating Costs 2018$/kW-year | Year | Onshore Wind Overnight Capital Costs 2018$/KW | Fixed Operating Costs 2018$/kW-year |
| 2018 | 1,731 | 52.36 | 2018 | 1,733 | 51.22 |
| 2019 | 1,733 | 51.98 | 2019 | 1,731 | 50.45 |
| 2020 | 1,736 | 51.60 | 2020 | 1,716 | 49.69 |
| 2021 | 1,738 | 51.22 | 2021 | 1,655 | 48.92 |
| 2022 | 1,741 | 50.83 | 2022 | 1,592 | 48.16 |
| 2023 | 1,744 | 50.45 | 2023 | 1,527 | 47.39 |
| 2024 | 1,747 | 50.07 | 2024 | 1,459 | 46.63 |
| 2025 | 1,749 | 49.69 | 2025 | 1,390 | 45.87 |
| 2026 | 1,752 | 49.31 | 2026 | 1,318 | 45.10 |
| 2027 | 1,755 | 48.92 | 2027 | 1,244 | 44.34 |
| 2028 | 1,758 | 48.54 | 2028 | 1,120 | 43.57 |
| 2029 | 1,761 | 48.16 | 2029 | 1,080 | 42.81 |
| 2030 | 1,764 | 47.78 | 2030 | 1,048 | 42.04 |
| 2031 | 1,768 | 47.39 | 2031 | 1,024 | 41.66 |
| 2032 | 1,771 | 47.01 | 2032 | 1,009 | 41.28 |
| 2033 | 1,774 | 46.63 | 2033 | 1,006 | 40.90 |
| 2034 | 1,777 | 46.25 | 2034 | 1,004 | 40.51 |
| 2035 | 1,781 | 45.87 | 2035 | 1,001 | 40.13 |
| 2036 | 1,784 | 45.48 | 2036 | 998 | 39.75 |
| 2037 | 1,788 | 45.10 | 2037 | 995 | 39.37 |
| 2038 | 1,792 | 44.72 | 2038 | 993 | 38.99 |
| 2039 | 1,795 | 44.34 | 2039 | 990 | 38.60 |

Source: NREL 2018 ATB, converted to $2018. (https://atb.nrel.gov/electricity/data.html)

### 6.5.2 Investment Tax Credit (ITC)

Consistent with the current policy, the IRP assumes the following: wind facilities that commence construction by December 31, 2018 will qualify for 18 percent ITC; wind facilities that commence

[33] Dated September 18, 2018

construction by December 31, 2019 will be reduced to 12 percent ITC; and zero percent afterwards. [34]

### 6.5.3 Project Development and Construction Time

The IRP assumes an accelerated timeline for wind projects similar to the solar PV projects, assuming 12 months for the development period (request for proposal, bid evaluation, permitting, and financing) and 12 months for construction.

### 6.5.4 Levelized Cost of Energy (LCOE)

For the IRP modeling, the levelized cost of energy (LCOE) is calculated as the net present value of the unit-cost of energy over the lifetime of the wind asset. The LCOE is then used as a proxy for the average price that the wind project could break even over its lifetime. Exhibit 6-41 shows the LCOE of wind under Mid case and Low case, determined using an expected capacity factor or 25% which is in line with observed values in the two existing Puerto Rico wind projects.

**Exhibit 6-41. Levelized Cost of Energy (LCOE) of Wind**

| Levelized Cost of Energy in Puerto Rico | | |
|---|---|---|
| Commercial On Line (COD) Year | Mid Case Wind 2018$/MWh | Low Case Wind 2018$/MWh |
| 2018 | 104 | 103 |
| 2019 | 111 | 110 |
| 2020 | 118 | 116 |
| 2021 | 132 | 126 |
| 2022 | 132 | 122 |
| 2023 | 132 | 118 |
| 2024 | 132 | 114 |
| 2025 | 132 | 110 |
| 2026 | 132 | 105 |
| 2027 | 132 | 101 |
| 2028 | 132 | 93 |
| 2029 | 132 | 90 |
| 2030 | 132 | 88 |
| 2031 | 132 | 87 |
| 2032 | 132 | 86 |
| 2033 | 132 | 85 |
| 2034 | 132 | 85 |
| 2035 | 132 | 84 |
| 2036 | 131 | 84 |
| 2037 | 131 | 84 |
| 2038 | 131 | 83 |

Exhibit 6-42 shows a comparison of the LCOE of wind with Solar PV. Note that even the Low Case for Wind is expected to be above the Mid Case for Solar PV. Moreover, a capacity factor of 30%

[34] http://programs.dsireusa.org/system/program/detail/658

would be required for the Low Wind Case to reach the same levels as the Mid Case Solar PV and approximately 40% for the Wind Low Case to reach the PV Low Case. Given that capacity factors at 30% or above are not expected in Puerto Rico and the model is assuming 23% at this time, Siemens doesn't expect that AURORA's LTCE will pick a wind alternative. Moreover, as shown in Exhibit 6-43, the wind generation in Puerto Rico is in general daytime peaking, making it correlated with Solar PV and reducing any diversity benefits.

Finally, Exhibit 6-44 and Exhibit 6-45 show the LCOE calculation for the Mid Case and Low Case, respectively, for Wind Turbine generation.

**Exhibit 6-42. Wind and Photovoltaic Levelized Cost of Energy (LCOE) $2018/MWh**

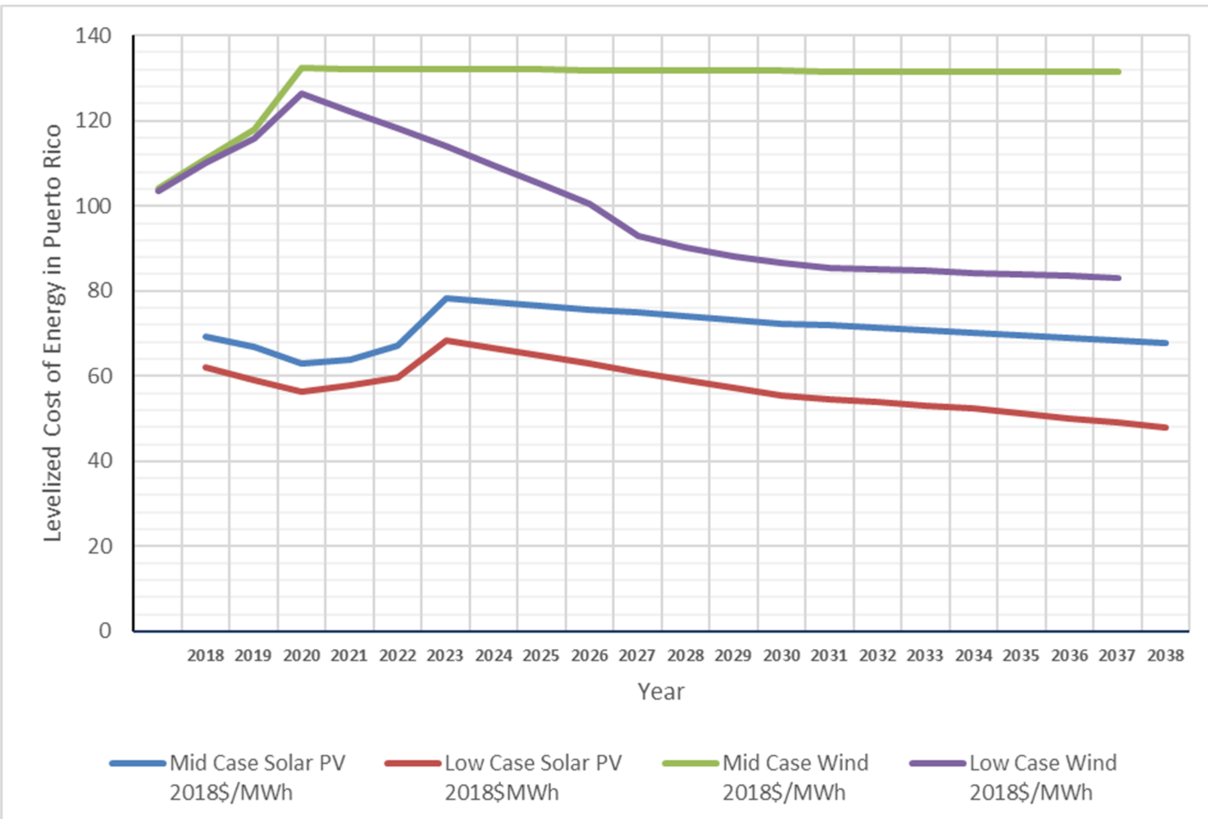
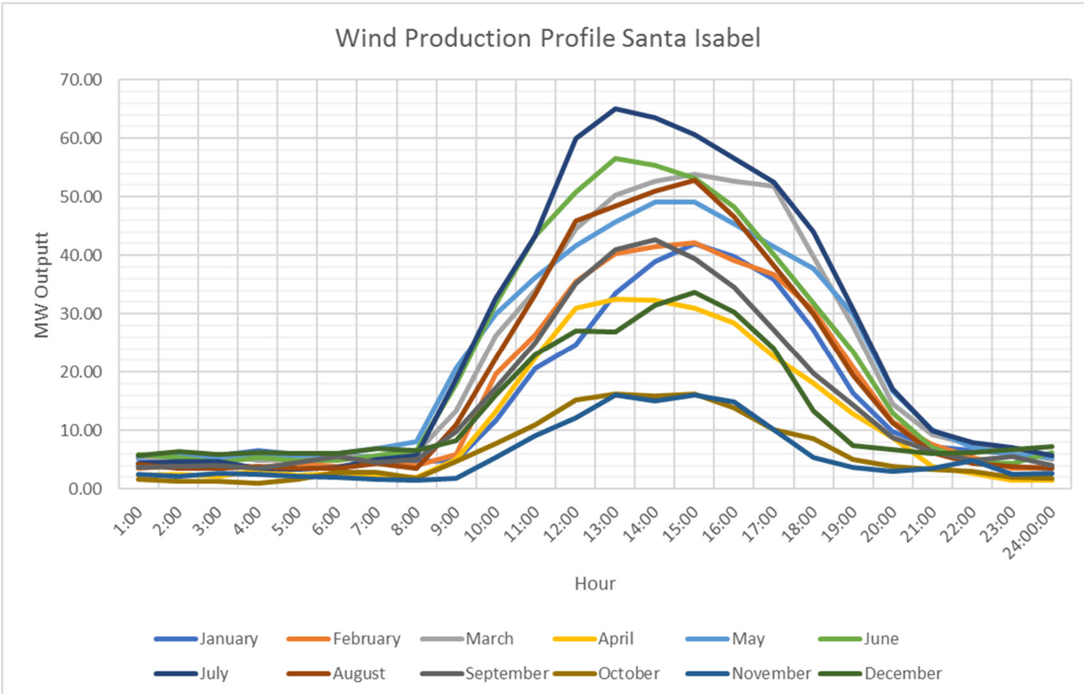


**Exhibit 6-43. Average hourly output at Santa Isabel per Month**



### Exhibit 6-44. Levelized Cost of Energy (LCOE) of Wind Generation – Base Case

| Commercial on line year | | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 | 2038 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Construction Start Year | | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2029 | 2034 | 2037 |
| **Capital and Operating Costs** | | | | | | | | | | | |
| Overnight Cost, US National, 100 MW | $2018/Watt | 1.73 | 1.74 | 1.74 | 1.74 | 1.74 | 1.75 | 1.75 | 1.76 | 1.78 | 1.79 |
| Puerto Rico Adder | % | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% |
| Overnight Cost, Puerto Rico, 100 MW | $2018/Watt | 2.01 | 2.01 | 2.02 | 2.02 | 2.02 | 2.03 | 2.03 | 2.05 | 2.07 | 2.08 |
| IDC Cost Adder | % | 2.5% | 2.5% | 2.5% | 2.5% | 2.5% | 2.5% | 2.5% | 2.5% | 2.5% | 2.5% |
| All-In Cost, Puerto Rico, 100 MW, $/Wac | $2018/Watt | 2.06 | 2.06 | 2.07 | 2.07 | 2.07 | 2.08 | 2.08 | 2.10 | 2.12 | 2.13 |
| Small Scale Adder (30 MW) | % | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Base Cost, Puerto Rico, 30 MW | $2018/Watt | **2.06** | **2.06** | **2.07** | **2.07** | **2.07** | **2.08** | **2.08** | **2.10** | **2.12** | **2.13** |
| Fixed O&M | $2018/kW-yr | 67.58 | 67.08 | 66.58 | 66.08 | 65.59 | 65.09 | 64.59 | 62.11 | 59.63 | 58.13 |
| | | | | | | | | | | | |
| **30 MW Wind Project Parameters** | | | | | | | | | | | |
| Capacity | MW | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 |
| Capacity Factor | % | 25% | 25% | 25% | 25% | 25% | 25% | 25% | 25% | 25% | 25% |
| Energy Produced | MWh | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 |
| | | | | | | | | | | | |
| Base Capital System | $2018 thousand | 61,806 | 61,895 | 61,986 | 62,080 | 62,176 | 62,274 | 62,375 | 62,910 | 63,500 | 63,881 |
| Interconnection Costs | $2018 thousand | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 |
| Total System Capital Costs | $2018 thousand | 64,646 | 64,735 | 64,827 | 64,920 | 65,016 | 65,115 | 65,215 | 65,750 | 66,341 | 66,722 |
| | | | | | | | | | | | |
| ITC | % | 18% | 12% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Income Tax | % | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% |
| Capital Recovery Factor | % | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% |
| Project Financing Factor | % | 86% | 94% | 109% | 109% | 109% | 109% | 109% | 109% | 109% | 109% |
| Construction Financing Factor | % | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 |
| | | | | | | | | | | | |
| **Annualized Capital Costs** | $2018 thousand | **5,267** | **5,745** | **6,695** | **6,705** | **6,715** | **6,725** | **6,735** | **6,790** | **6,851** | **6,891** |
| Fixed O&M | $2018 thousand | 2,027 | 2,012 | 1,997 | 1,983 | 1,968 | 1,953 | 1,938 | 1,863 | 1,789 | 1,744 |
| **Total Base System Cost** | $2018 thousand | **7,295** | **7,757** | **8,692** | **8,687** | **8,682** | **8,677** | **8,673** | **8,654** | **8,640** | **8,635** |
| **Levelized Cost of Energy (Base)** | $2018/MWh | **111** | **118** | **132** | **132** | **132** | **132** | **132** | **132** | **132** | **131** |

## Exhibit 6-45. Levelized Cost of Energy (LCOE) of Wind Generation – Low Case

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Commercial on line year | | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2030 | 2035 | 2038 |
| Construction Start Year | | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2029 | 2034 | 2037 |
| **Capital and Operating Costs** | | | | | | | | | | | |
| Overnight Cost, US National, 100 MW | $2018/Watt | 1.73 | 1.72 | 1.65 | 1.59 | 1.53 | 1.46 | 1.39 | 1.05 | 1.00 | 0.99 |
| Puerto Rico Adder | % | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% |
| Overnight Cost, Puerto Rico, 100 MW | $2018/Watt | 2.01 | 1.99 | 1.92 | 1.85 | 1.77 | 1.69 | 1.61 | 1.22 | 1.16 | 1.15 |
| IDC Cost Adder | % | 2.5% | 2.5% | 2.5% | 2.5% | 2.5% | 2.5% | 2.5% | 2.5% | 2.5% | 2.5% |
| All-In Cost, Puerto Rico, 100 MW, $/Wac | $2018/Watt | 2.06 | 2.04 | 1.97 | 1.89 | 1.81 | 1.73 | 1.65 | 1.25 | 1.19 | 1.18 |
| Small Scale Adder (30 MW) | % | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Base Cost, Puerto Rico, 30 MW | $2018/Watt | **2.06** | **2.04** | **1.97** | **1.89** | **1.81** | **1.73** | **1.65** | **1.25** | **1.19** | **1.18** |
| Fixed O&M | $2018/kW-yr | 65.59 | 64.59 | 63.60 | 62.61 | 61.61 | 60.62 | 59.63 | 54.66 | 52.17 | 50.68 |
| | | | | | | | | | | | |
| **30 MW Wind Project Parameters** | | | | | | | | | | | |
| Capacity | MW | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 |
| Capacity Factor | % | 25% | 25% | 25% | 25% | 25% | 25% | 25% | 25% | 25% | 25% |
| Energy Produced | MWh | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 | 65,700 |
| | | | | | | | | | | | |
| Base Capital System | $2018 thousand | 61,721 | 61,180 | 59,003 | 56,755 | 54,431 | 52,029 | 49,551 | 37,360 | 35,685 | 35,390 |
| Interconnection Costs | $2018 thousand | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 | 2,840 |
| Total System Capital Costs | $2018 thousand | 64,562 | 64,020 | 61,843 | 59,596 | 57,271 | 54,870 | 52,391 | 40,201 | 38,525 | 38,230 |
| | | | | | | | | | | | |
| ITC | % | 18% | 12% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Income Tax | % | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% |
| Capital Recovery Factor | % | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% |
| Project Financing Factor | % | 86% | 94% | 109% | 109% | 109% | 109% | 109% | 109% | 109% | 109% |
| Construction Financing Factor | % | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 |
| | | | | | | | | | | | |
| **Annualized Capital Costs** | $2018 thousand | **5,260** | **5,681** | **6,387** | **6,155** | **5,915** | **5,667** | **5,411** | **4,152** | **3,979** | **3,948** |
| Fixed O&M | $2018 thousand | 1,968 | 1,938 | 1,908 | 1,878 | 1,848 | 1,819 | 1,789 | 1,640 | 1,565 | 1,520 |
| **Total Base System Cost** | $2018 thousand | **7,228** | **7,619** | **8,295** | **8,033** | **7,763** | **7,485** | **7,199** | **5,791** | **5,544** | **5,469** |
| **Levelized Cost of Energy (Base)** | $2018/MWh | **110** | **116** | **126** | **122** | **118** | **114** | **110** | **88** | **84** | **83** |

Part

7

# Assumptions and Forecasts

This section provides two remaining aspects necessary for the IRP, fuel infrastructure forecast and an estimation of the Value of Lost Load (VOLL) for Puerto Rico.

## 7.1 Fuel Infrastructure and Forecast

### 7.1.1 Fuel Infrastructure Options

The purpose of this review is to identify the requirements for using or developing the fuel infrastructure needed to support the generation options considered in the IRP. Specific objectives include:

- Identify current fuel infrastructure options;
- Evaluate sources of natural gas delivered to Puerto Rico such as liquefied natural gas (LNG);
- Identify LNG or natural gas transport infrastructure needs relative to key generation sites at Aguirre and Costa Sur in the south, San Juan and Palo Seco in the north, Mayagüez in the west, and Yabucoa in the east; and
- Review alternative liquid fuels' attractiveness and deliverability.

As a power generation fuel, natural gas is superior to petroleum products like diesel and residual fuel oil because it has lower air emissions, higher efficiency, greater operating flexibility, and lower costs. The inherent sulfur and particulate content of natural gas processed as LNG is extremely low. Carbon dioxide emissions from natural gas combustion are also lower relative to liquid fuels.[35] With state-of-the-art controls such as low-$NO_x$ burners, $NO_x$ emissions can be lower as well. Natural gas allows the use of advanced combined cycle technology (although diesel can be used as a fuel for less advanced combined cycle technology), which is the most fuel-efficient thermal power generation technology available today.[36] Advanced gas turbines cannot fire residual fuel oil because of

[35] According to the EIA (https://www.eia.gov/environment/emissions/co2_vol_mass.php), natural gas emits 67%, 73%, and 84% of the $CO_2$ as compared to residual fuel oil, diesel, and propane, respectively.

[36] The EIA (https://www.eia.gov/electricity/annual/html/epa_08_02.html) reports that current natural gas-fired combined cycle plants have an average heat rate of 7,652 Btu/kWh vs. 9,179 Btu/kWh for internal combustion and 11,214 Btu/kWh for gas turbine.

its high ash content. In addition, natural gas has been significantly less expensive since 2009 compared to premium liquid fuels such as diesel and residual fuel oil, primarily due to the shale gas boom in the U.S. (see Exhibit 7-2). However, the benefits of natural gas can be realized only if it can be delivered in a cost-effective manner to Puerto Rico and then distributed to power generation sites. The need to expand the island's LNG import capability and natural gas distribution pipelines would require significant new fuel infrastructure investments in order to realize Puerto Rico's potential benefit from greater natural gas use for power generation.

The U.S. mainland currently has two LNG export terminals in operation and four more under construction; collectively representing 71.05 million tons per annum (MMtpa) of nameplate capacity that will be online by 2021. More than 300 MMtpa of additional capacity has been proposed, most of which will not be realized but some of which may constitute a second wave of liquefaction capacity buildout in the mid- to late-2020s. Exhibit 7-1 below describes the existing LNG capacity in the mainland U.S. The total contracted capacity is equal to 63.08 MMtpa or 88.8% of nameplate capacity. While this leaves nearly 8 MMtpa of uncontracted capacity that could potentially satisfy Puerto Rico's LNG demand (estimated to be no higher than 6.5 MMtpa), these U.S.-based LNG export facilities would require Jones Act-compliant ships to ferry LNG to Puerto Rico. The Jones Act requires goods traveling between U.S. ports to do so on ships constructed and flagged in America, with primarily U.S. crews. However, there are not any Jones Act-compliant, large-scale U.S. vessels that can carry LNG in large onboard tanks. In addition, no American shipyard has constructed an LNG carrier in nearly four decades (although there are U.S. vessels that could carry LNG in ISO containers). This reason, among others, is why Puerto Rico primarily receives its LNG supply from Trinidad & Tobago. Exhibit 7-1 summarizes total and contracted U.S. export facility capacity by terminal.

**Exhibit 7-1. U.S. Mainland Large-Scale LNG Export Capacity (MMtpa)**

| LNG Facility | Status | Nameplate Capacity | Contracted Capacity |
|---|---|---|---|
| Sabine Pass | Operational | 22.5 | 19.8 |
| Dominion Cove Point | Operational | 5.3 | 4.6 |
| Freeport | Under Construction | 15.3 | 13.6 |
| Cameron | Under Construction | 12.0 | 12.0 |
| Corpus Christi | Under Construction | 13.5 | 10.6 |
| Elba Island | Under Construction | 2.5 | 2.5 |

Source: Siemens.

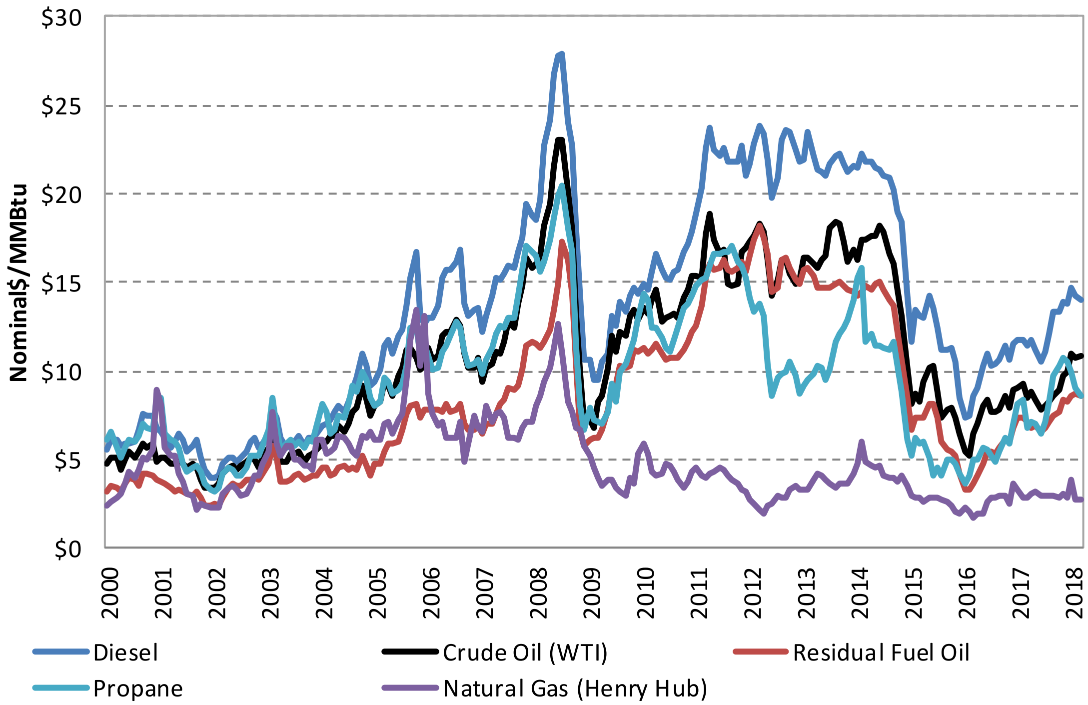
LNG terminals and infrastructure can play an important role in sourcing cleaner and less expensive LNG. Robust options for natural gas supply provide flexibility to enhance security of supply (backup) to each generating site, as well as commercial value in negotiating and selecting the most advantageous pricing over time among various fuel suppliers.

The EcoEléctrica LNG Import Terminal has been operating successfully since 2000. In 2017, the Federal Energy Regulatory Commission (FERC) approved a change in operations to expand the terminal's natural gas send-out beyond its own 507 MW combined cycle unit to include supply to PREPA's 820 MW Costa Sur generating plant. The terminal send-out capacity was increased by 93 MMcf/d, from 186 MMcf/d to 279 MMcf/d, by putting into service an idle gasifier (the third such gasifier) and can be expanded by a further 93 MMcf/d by putting into service the remaining spare gasifier (the fourth such gasifier). EcoEléctrica delivers 186 MMcf/d of regasified LNG to the Costa Sur plant through a renegotiated contract (as of May 2018, Costa Sur is running exclusively on natural gas) while the remaining 93 MMcf/d supplies its own combined cycle plant. Beyond the maximum send-out capacity of 372 MMcf/d (if the fourth gasifier is put into service), a major increase in LNG terminal throughput could require some modifications, possibly including a second LNG storage tank[37]. It must be noted that EcoEléctrica is a private company and expanded natural gas supply from this terminal would require PREPA, at a minimum, to contractually commit to a long-term natural gas processing and/or purchase agreement to justify infrastructure investments.

Fuel (including diesel and residual fuel oil) together with purchased power is the predominant cost and most volatile rate component for PREPA. Reducing dependence on oil for power generation has long been a top priority for PREPA. Although progress has been made, oil remains the main source of energy generation. An estimated 45% of generation is from oil, compared to the national average of 4%. PREPA has an aspirational goal of a 20-25% cost reduction ($400-500 million) from fuel and purchased power under pre-storm conditions by FY 2023. One component, purchased power, is under two long-term Power Purchase Agreements (PPAs) that extend through 2022 and 2027, respectively, and thus are not easily altered. Fuel prices are the other component and have been historically volatile, particularly oil and its derivative diesel and residual fuel oil products. Prices have been increasing since a recent low point in 2016. Exhibit 7-2 below provides a comparison of the U.S. fuel prices from 2000 to March 2018 on an energy-equivalent nominal $/MMBtu basis. Natural gas has been the least-cost of these five fuels consistently for nearly a decade and in more recent history has exhibited significantly less price volatility.

[37] A second LNG tank was included in the original permit but was not constructed, and the permit has expired. So, a new permitting effort would be required for such an expansion.

**Exhibit 7-2. U.S. Fuel Prices (Nominal $/MMBtu)**




Source: Siemens, EIA.

Puerto Rico's electrical infrastructure was critically damaged during September 2017, when Hurricanes Irma and Maria delivered back-to-back blows to the Island, resulting in a complex and prolonged disaster recovery effort. Hurricane Irma skirted the northern coast of the Island from September 6–7, 2017 as a Category 5 storm, causing significant flooding, regional power and water outages, and other impacts to the Island's infrastructure. Exactly 13 days later, on September 20th, and before Irma's response operations had concluded, Hurricane Maria slammed into Puerto Rico, making a direct strike as a strong Category 4 storm causing widespread devastation.

The following sections describe the pre-storm fuel infrastructure as well as proposed fuel infrastructure during the recovery and rebuilding phases after the storms.

## 7.1.2 Pre-Storm Fuel Infrastructure

### 7.1.2.1 Residual Fuel Oil (No. 6 Fuel Oil)

Puerto Rico has three steam-electric power plants which burn residual fuel oil. These are Palo Seco and San Juan in the north and Aguirre located on the south coast. The Costa Sur plant, located on the southwestern coast, is dual-fuel, capable of burning either residual fuel oil or natural gas. However, as of May 2018 it is burning exclusively natural gas. The San Juan and Aguirre facilities have additional combined-cycle plants that burn diesel. Residual fuel oil is delivered to Puerto Rico by vessel. It is stored centrally at the former Commonwealth Oil Refinery complex on the south-west side of the island. From there, it is piped to the nearby Costa Sur plant and delivered by barge to the other three plants. Each of the three steam-electric plants has onsite storage for residual fuel oil. Palo Seco has capacity to store 450,000 barrels, San Juan 138,000 barrels, and Aguirre 780,000 barrels. Costa Sur has 800,000 barrels of storage that could be converted for other use. Based on 2013 generation Exhibits, this storage capacity represents approximately a 36-day supply for Palo Seco, 14 day supply for San Juan, and 40 day supply for Aguirre. The plants typically hold at least 15 days of fuel supply onsite.

#### 7.1.2.2 Diesel (No. 2 Fuel Oil aka Distillate Fuel Oil)

Diesel is used at the combined-cycle units at Aguirre and San Juan and the combustion-turbine units at Cambalache, Mayagüez, and nine other small facilities around the island. Diesel fuel is delivered to storage facilities at Yabucoa and Bayamon and from there is barged to four larger stations (Aguirre, San Juan, Cambalache and Mayagüez). The nine other small facilities around the island operate infrequently and receive fuel deliveries by truck when required. The San Juan 2x200 MW combined cycle diesel-fired Units 5 and 6 have an attractive heat rate and could be converted to burn natural gas for a relatively modest investment of $10-30 million. If San Juan natural gas delivery is established, it is likely that San Juan Units 7, 8, 9, and 10 could be replaced with more efficient units. The Yabucoa facility has storage capacity for four million barrels of crude oil, fuel oil, and refined products. The Bayamon facility has storage capacity for 3.5 million barrels. A 2013 report indicates that there are two diesel fuel transfer lines between the Palo Seco and San Juan plants that are in service. There is no information regarding onsite storage for diesel at any of the other plants.

#### 7.1.2.3 Natural Gas

Natural gas is used at the privately-owned EcoEléctrica cogeneration facility and at the Costa Sur steam plant, which are both located at Guayanilla Bay on the southwestern coast where the Peñuelas terminal and regasification facility is located. Natural gas is imported as LNG, mainly from Trinidad and Tobago (92% since 2010, under a 20-year contract for 0.5 MMtpa expiring in 2019, according to Energy Velocity). The EcoEléctrica plant is adjacent to the regasification facility and the Costa Sur plant receives gas via a short pipeline. The 2017 expansion of regasification facilities at EcoEléctrica LNG Import Terminal allows Costa Sur, which has dual-fuel units, to also be fully fired by LNG. As of May 2018, Costa Sur is now burning exclusively natural gas. There is a substantial take-or-pay gas contract in place that requires significant generation from Costa Sur.

Storage for one million barrels of LNG is available at the regasification facility. Based on the original FERC application, EcoEléctrica was approved to construct two, one-million-barrel (160,000 cubic meters) LNG storage tanks. However, the second storage tank was never constructed and FERC authorization to construct the second tank has lapsed. However, the space remains available to construct the second tank if needed. Prior to 2017, the facility had two spare regasifiers. In 2017, it obtained FERC approval to put one of them into continuous service and to increase total sendout capacity from the import terminal to 279 MMcf/d. This increased LNG cargo (ship) deliveries to 40 per year from 24 per year. The FERC approval of the third gasifier allowed the gas received by Costa Sur to double to 186 MMcf/d from 93 MMcf/d. The remaining spare (fourth) gasifier also has a capacity of 93 MMcf/d, which would increase total plant sendout to 372 MMcf/d if put into service. Some steps were taken prior to 2013 to convert some of the other steam plants to natural gas, but these were put on hold due to uncertain gas supply following the hurricanes and cancellation of a cross-island pipeline project. There are also pre-existing plans to build the Aguirre Offshore GasPort, a floating storage and regasification unit offshore near the Aguirre plant that would be operational no later than January 1, 2022 and to convert the Aguirre plant to natural gas.

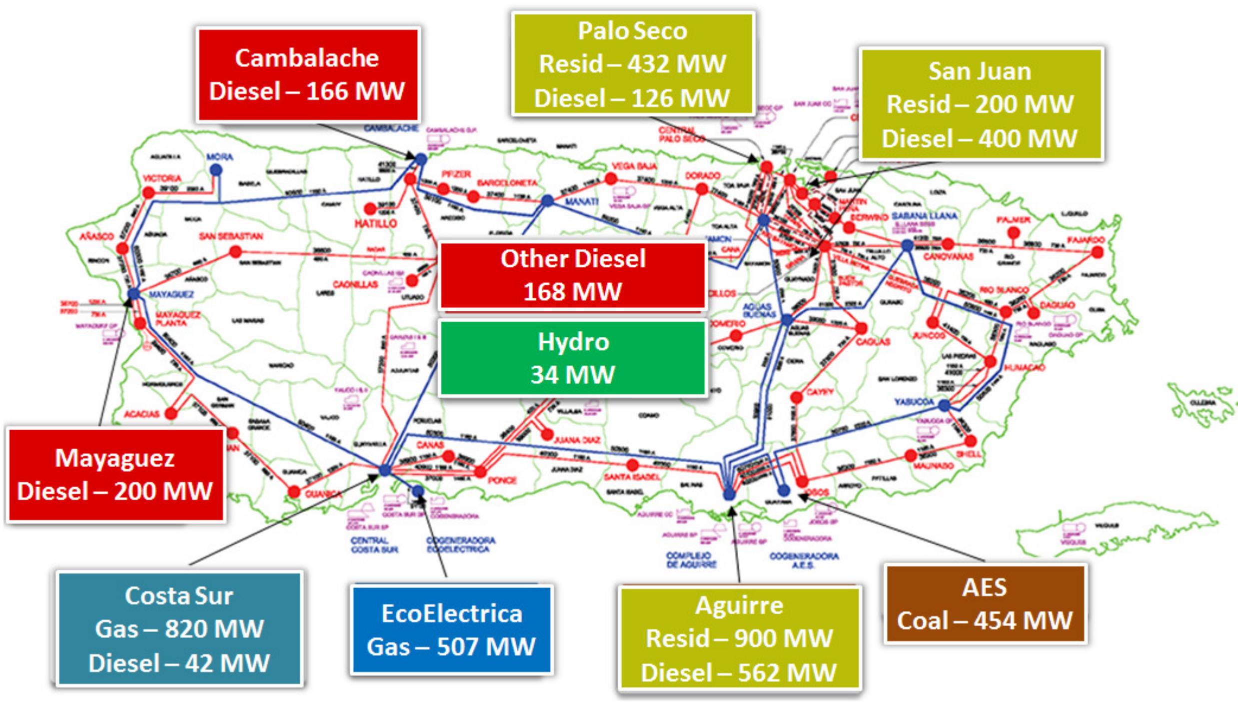
### 7.1.2.4 Coal

The privately-owned AES-Puerto Rico facility burns Colombian bituminous coal. The coal is delivered to Puerto Rico at the Las Mareas Port, just south of the plant site and is transported to the plant via covered conveyors. AES maintains a 30-day inactive coal storage supply to address potential delivery interruptions and a 20-day active storage supply.

### 7.1.2.5 Independent Power Production

IPP generation contributions to the island is contracted through 2022 for EcoEléctrica's 507 MW and 2027 for AES' 454 MW. Locations of the electric generating units in Puerto Rico are presented in Exhibit 7-3.

**Exhibit 7-3. Current PREPA Generating Map**




Source: PREPA, Siemens

### 7.1.2.6 Proposed Fuel Infrastructure and Natural Gas-Fired Generation Changes

Currently, only 22 percent of PREPA-owned generation is natural gas-fired. In the aftermath of the hurricanes, PREPA is considering options for new infrastructure, including the possibility to convert certain diesel or residual fuel oil units to natural gas. Such conversions would help to meet the requirements under the U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS) regulations as well as to take advantage of abundant and low-cost natural gas from the mainland. One such option is to convert San Juan Units 5 and 6, which represent 400 MW of relatively new (2008) and reliable baseload generation, from expensive diesel to cheaper natural gas in the form of LNG. The estimated total annual fuel requirements for these two units would be on the order of 24-25 TBtu/yr, assuming a heat rate of 7,652 Btu/kWh and a capacity factor of 89-93%. To facilitate conversion, the San Juan plant would require a natural gas receiving, storage, and supply system.

In addition to possible natural gas-fired generation changes, PREPA is considering several fuel infrastructure options in its 2018 IRP. These options include the following, in no implied priority:

- Aguirre Offshore GasPort
- Ship-based LNG at San Juan with pipeline to Palo Seco
- Land-based LNG at San Juan with pipeline to Palo Seco
- Ship-based LNG at Mayagüez (west)
- Ship-based LNG at Yabucoa (east)
- LNG or compressed natural gas (CNG) delivery to San Juan and potentially Palo Seco
- Additional regasification capacity and new natural gas pipelines, first from EcoEléctrica LNG Import Terminal to Aguirre and then to San Juan
- No new gas infrastructure

This analysis reviews the many considerations surrounding these options without presupposing that any option is a required solution for supporting projected electricity demand or for compliance with any regulatory requirements. This section is followed by a section discussing these fuel infrastructure scenarios and the issues and considerations reflecting each scenario.

#### 7.1.2.7 Aguirre Offshore GasPort

On April 17, 2013, Aguirre Offshore GasPort, LLC (Aguirre LLC), a wholly-owned subsidiary of Excelerate Energy, LP, filed an application with FERC to develop a floating offshore LNG regasification facility called Aguirre Offshore GasPort (AOGP) to supply natural gas to PREPA's existing Aguirre Power Complex in Salinas, Puerto Rico. The AOGP facility would consist of an offshore berthing platform, a floating storage and regasification unit (FSRU), and a 4-mile-long, 21-inch outside diameter subsea pipeline connecting to the Aguirre Power Complex. AOGP was being developed with cooperation between Excelerate Energy, LP and PREPA.

Under the Aguirre LLC application, the AOGP would provide LNG storage capacity and sustained deliverability of natural gas to the Aguirre plant. The AOGP facility would assist PREPA's plan to convert the Aguirre plant from a residual fuel oil- and diesel-only plant to a facility capable of burning diesel and natural gas for the combined cycle units and heavy fuel oil and natural gas for the thermoelectric plant. The AOGP facility would have LNG storage capacity of 3.2 Bcf (150,000 cubic meters) and a natural gas send out capacity of 500 MMcf/d (peaking deliverability of up to 600 MMcf/d) to the Aguirre plant. Based on data from Aguirre LLC, the estimated total construction period for AOGP facility was approximately 12 months, and total capital cost of AOGP facility was estimated (inflated to 2018$) at $403 million (including onshore and offshore components, permits, financing costs, etc.). This estimation does not include the capital cost related to fuel conversion of the Aguirre power plant which PREPA has estimated the annual fixed operating costs to be approximately $81.5 million, excluding debt service.

The existing Aguirre units include 1,462 MW of diesel- and residual fuel oil-fired generation. If converted to natural gas, the expectation is that the maximum capacity of gas-fired generation would be 1,076 MW. The maximum daily volume of natural gas estimated to be required for this converted capacity would equal 155 MMcf/d. For the purpose of forecasting delivered natural gas prices to Aguirre, Siemens used an offtaker pricing formula similar to those used by large-scale Gulf Coast LNG offtakers in order to represent the estimated delivered cost to supply gas to Aguirre via AOGP. This pricing formula ($Price\ of\ Natural\ Gas$ = 1.15 * Henry Hub + 4.35), together with the average daily gas burn volume at an 80% generation capacity factor, gives a range from $423 million to $639 million in annual fuel supply costs each year of operation. This gives a starting point for estimating the required revenues the power generation plant would require supporting the capital, operating, and financing costs for AOGP.

PREPA commissioned a detailed economic analysis of the AOGP project using four resource plans and three price scenarios[38]. The analysis concluded that the AOGP base price scenario (where the base price is derived from the U.S. Energy Information Administration's Annual Energy Outlook 2017) demonstrated the benefits of AOGP as compared to the No AOGP base price scenario. The conclusion results from the AOGP base scenario having lower overall system costs on the order of $3.42 billion due to higher fuel costs incurred without AOGP. A similar benefit-cost analysis conclusion in favor of the AOGP project was reached when using a high oil price scenario both with and without full Renewable Portfolio Standard (RPS) compliance. However, the AOGP low oil price scenarios both with and without full RPS compliance were found to have a higher system costs than without the AOGP project. Based on these results, the economic analysis recommended proceeding with the AOGP project and associated Aguirre unit conversions.

Immediately following the second hurricane in September 2017, the Governor of Puerto Rico declared a state of emergency due to the devastation of Hurricane Maria. The widespread damage inflicted by Hurricane Maria, resulted in the Puerto Rico Energy Commission[39] (PREC) issuing an order[40] (dated April 26, 2018 for Case No. CEPR-AP-2017-0001) staying all proceedings to allow PREPA to focus on restoring electric service, including the proceeding on the AOGP project. Prior to this event, in early July 2017, PREPA's Fiscal Oversight and Management Board (FOMB) filed for protection under Title III of PROMESA. Later in July 2017, Excelerate Energy LP, the contractor for the AOGP project, announced

[38] http://energia.pr.gov/wp-content/uploads/2017/05/PREPA-Ex-1.02-Part-1-Economic-Analysis-Report.pdf

[39] PREC is now known as the Puerto Rico Energy Bureau (PREB)

[40] http://energia.pr.gov/wp-content/uploads/2018/04/Final-Resolution-and-Order-CEPR-AP-2017-0001.pdf

that it had canceled its contracts with PREPA to construct the natural gas terminal. As a result of these events, PREC delayed any consideration of AOGP until such time as PREPA decides to pursue the project as part of its 2018 IRP. PREPA's March 2018 draft fiscal plan assumes AOGP is completed and Aguirre plants are converted to run on natural gas by January 1, 2022. If AOGP does not proceed, PREPA may consider other LNG supply options. In the meantime, residual fuel oil and diesel will continue to be primary fuels at Aguirre at a higher cost than for power generated using LNG.

A March 2017 Siemens PTI fuel delivery assessment[41] analyzed the feasibility of containerized LNG or CNG to the Aguirre power station absent the AOGP project. The assessment found that containerized LNG deliveries would require 193 ISO containers per day while CNG deliveries would require 617 containers per day to meet project demand at the power plant. As a result, LNG delivery in ISO containers to Aguirre, absent AOGP, was determined to be impractical due to the expected gas demand and the amount of container handling required on a daily basis and vessel deliveries required on an annual basis.

As mentioned earlier, the IRP will consider other LNG options to bring natural gas to the island and the AOGP is not currently being studied as part of the core IRP. It remains Siemens view that the possible benefits to the AOGP project (together with upgrades to the Aguirre generating plant to use natural gas) include lower overall system costs compared to current infrastructure in either a base case price or a high oil price scenario. The AOGP options brings the befits of lower carbon emissions from the Aguirre generation plant by burning more natural gas compared to current emissions, greater flexibility and security in fuel supply options, the ability to repurpose AOGP infrastructure (the floating storage and regasification unit could be sold and moved), and the potential to increase PREPA-owned generation as IPP contracts roll off in 2022 and 2027. However, the AOGP option brings the risks of potential of sustained low-oil prices could render AOGP uneconomic, new fuel infrastructure that could be vulnerable to hurricanes, the possibility of a decreasing need for fossil generation as load decreases with further population out-migration or increases in energy efficiency and renewable energy penetration, and continued dependence on south-to-north electricity transmission to reach load centers on the north side of the Island.

PREPA has addressed some of the concerns raised by PREC following the last IRP filed in 2015. One such concern related to the overall economic benefit of AOGP, which was addressed in detail in the economic analysis mentioned previously[42] and found to be generally favorable. In addition, the present IRP addresses a second concern, namely that PREPA must perform a comprehensive review of its options using a capacity expansion model that would test the AOGP against optimized portfolios that could achieve the same benefits as the AOGP with a different set of resources. However, PREPA still requires a clearly defined plan to obtaining all necessary permits as well as a potential partner to construct the AOGP. With Excelerate's cancellation of contracts in July 2017, PREPA would need to solicit renewed interest in the project from potential partners.

[41] http://energia.pr.gov/wp-content/uploads/2017/05/PREPA-Ex-1-04-PREPA-Fuel-Delivery-Option-Assessment.pdf

[42] http://energia.pr.gov/wp-content/uploads/2017/05/PREPA-Ex-1.02-Part-1-Economic-Analysis-Report.pdf

### 7.1.2.8 Ship-based LNG (or CNG) at San Juan with Possible Pipeline to Palo Seco

PREPA has studied a ship-based standard-scale LNG (and CNG) receiving terminal in the San Juan area, including a ship-based (offshore) option known as a floating storage and regasification unit (FSRU). A June 2015 Galway Energy Advisors natural gas study for PREPA's northern power plants (San Juan and Palo Seco) evaluated the feasibility and potential fatal flaws of an import facility sized to handle 125,000 MMBtu per day. The study looked at importing either LNG or CNG. Given the lack of CNG project examples in the U.S. and PREPA's preference for 1-2 deliveries per month to limit traffic in the already busy San Juan port, the fuel choice of the higher volume CNG was evaluated but was considered less viable than LNG supplied via standard scale LNG ships delivering 2.0-3.6 million MMBtu per ship.

The Galway study considered one ship-based (offshore) and three land-based (onshore) options with 14 configurations, including an LNG regasification barge, an LNG FSRU, an LNG floating storage unit (FSU) with onshore vaporization, LNG and CNG onshore storage and vaporization, and non-self-propelled vessels with onboard CNG storage. All of the four site options would require one or more pipelines to deliver vaporized LNG or depressurized CNG to the power plants. Several considerations were weighed for a ship-based LNG terminal. Concerns identified with this option included potential harm to environmentally sensitive zones where coral reefs, mangroves, sea grass beds, wetlands, critical wildlife areas, rivers and streams, karst areas, and aquifers exist. In addition, harbor view impacts were considered, wherein the visual impact on residents was assessed. In general, an FSRU would be sited approximately three miles offshore, but would need to be sited 13 miles or more offshore to be completely out of sight of harbor residents. A location 13 miles offshore would require a lengthy pipeline, with its own environmental risks and added costs, to bring supply to the plants. The analysis reached the conclusion that among the 14 options, the most feasible option would be land-based (onshore) LNG storage and vaporization at a warehouse site adjacent to the San Juan power station and with standard scale LNG carrier delivery directly to onshore tanks.

A separate 2018 study[43] evaluated the economics of land-based (onshore) LNG storage and vaporization and compared to FSRU receiving terminals through the assessment of analyses performed for Indonesia, an island nation best served by LNG. An FSRU terminal in Sorong, Indonesia was estimated to be $0.6 million per MMcf/d in capital costs versus $2.1 million per MMcf/d for a land-based option. The FSRU vs. land-based (onshore) LNG produced an internal rate of return (IRR) of 13.77% vs. -0.27%, respectively, with the principle difference in IRR due to the difference in the 3.5:1 capital costs ratio. The study affirmed the use of a $4.35 per MMBtu transportation adder (liquefaction + transportation + margin) for LNG from the Gulf Coast, Trinidad & Tobago, or other nearby source. However, differences in volume and location-based costs exist between the Indonesian example and San Juan port, and this rule-of-thumb estimate predicts a lower capital cost estimate for the FSRU. A different 2017

[43] "An Economic Evaluation of Onshore and Floating Liquefied Natural Gas Receiving Terminals: the Case Study of Indonesia," Giranza and Bergmann (2018), http://iopscience.iop.org/article/10.1088/1755-1315/150/1/012026/pdf

study[44] estimated the cost for a new 30,000 $m^2$ LNG tanker at $105 million, which is the Exhibit used in this analysis (together with an additional $80 million in costs for regasification, jetty, piping, etc.). It is possible to reduce the capital cost for an FSRU by the utilization of a used LNG tanker, which could also reduce, by up to half, the time to implement the FSRU project. A September 2018 announcement by TEMA LNG Terminal Co Ltd[45] puts the cost of an estimated small-scale 20,000 $m^2$ FSU based in Ghana at $350 million with an 18 month project timeframe. In any event, the FSRU option is expected to remain the lower cost option vs. land-based LNG to meet the fuel needs of San Juan and Palo Seco plants. The FSRU option comes with the added benefit that it could potentially be repurposed, and the terminal moved or sold to recover some of the initial capital investment.

New Fortress Energy proposed an offshore natural gas fuel supply option to provide San Juan and Palo Seco with LNG. The company has signed a 20-year deal to supply natural gas to Jamaica and could use the country as a hub to sell LNG to Puerto Rico. The intent of the New Fortress Energy proposal would provide for all-in fuel delivery to San Juan with optional included conversion of San Juan units 5 and 6. The delivered LNG price would be negotiated but there would be no long-term commitment or upfront capital cost commitment. The capital investment would be recovered through a calculated gas adder to the rate. Alternatively, Trinidad & Tobago is the primary supplier of LNG to Puerto Rico and since 2010 has shipped an average of 2.1 Bcf/month of natural gas to EcoEléctrica Inc. as well as additional LNG (since 2012) to Costa Sur via the same EcoEléctrica LNG Import Terminal.

Ship-based LNG delivery to the San Juan region with ship-based or onshore LNG storage and vaporization is a viable fuel infrastructure option for PREPA. However, the most likely scenario is a medium-scale LNG ship (30,000 $m^2$) rather than a large-scale LNG carrier (85,000 $m^3$ to 170,000 $m^3$ or more), which would require dredging large quantities of material from the San Juan harbor to create a channel suitable for the large-scale LNG carriers. The potential benefits of the option for medium-scale LNG carriers (with regasification either floating or land-based) include efficient delivery of cost-competitive bulk LNG with minimal impact from increased ship traffic, reduced carbon emissions by converting units at San Juan and Palo Seco to natural gas from residual fuel oil, and lower fuel costs compared to current infrastructure in either a base case price or a high oil price scenario. Possible risks include a sustained low-oil price future rendering operating costs higher using natural gas than residual fuel oil, the creation of new fuel infrastructure that could be vulnerable to hurricanes, supply chain vulnerability preventing timely delivery of LNG, and the possibility of a decreasing need for fossil generation as load decreases with further population out-migration or as PREPA increases energy efficiency programs and renewable energy penetration.

Onshore LNG storage offers advantages and disadvantage compared to ship-based offshore storage (FSU) and/or regasification (FSRU) or regasification. The FSU and FSRU options would need to go through a permitting process with the Federal Energy Regulatory

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[44] "Small Scale LNG: Emerging Technologies for Small-Scale Grids," Tony Regan, DataFusion Associates, http://esi.nus.edu.sg/docs/default-source/doc/smallscale-lng---esi-roundtable.pdf?sfvrsn=2&_sm_au_=iVVVtq5FtZNFJDTM

[45] Jiangnan to build regas barge for Ghana's first LNG import project, Mike Corkhill, LNG Shipping World, https://www.lngworldshipping.com/news/view,jiangnan-to-build-regas-barge-for-ghanas-first-lng-import-project_54246.htm

Commission (FERC), the U.S. EPA, the U.S. Department of Transportation Maritime Administration, the U.S. Coast Guard, local agencies in Puerto Rico, and would be subject to regulatory siting challenges resulting from large exclusion zones in the harbor. Furthermore, several existing statutes would need to be navigated, including the Natural Gas Act, the Clean Air Act, the Clean Water Act, the Deepwater Port Act, the National Environmental Policy Act, the Comprehensive Environmental Response, Compensation, and Liability Act, the Maritime Protection, Research, and Sanctuaries Act, the Resource Conservation and Recovery Act, the Rivers and Harbors Act, and others.46 All offshore pipelines would require a subsea pipeline to both San Juan and Palo Seco power plants. By contrast, the onshore LNG storage option would be co-located by the San Juan plant with a connecting pipeline to Palo Seco. This onshore option would avoid some of the regulatory requirements mentioned above with the FSU and FSRU options but would be subject to its own regulatory challenges. The onshore LNG storage and FSU/FSRU options would likely be mutually exclusive due to land use and/or port lease issues as well as cost prohibitive due to duplicative infrastructure buildout.

A ship-based FSRU would occupy one of two berths directly in front of the San Juan steam plant. Based on an estimated 350 MW gas-fired capacity at San Juan, the maximum daily gas volume requirement would not exceed 50.4 MMcf/d. However, if a pipeline to the Palo Seco plant is included, adding an incremental 300 MW of gas-fired capacity at Palo Seco, the maximum daily gas volume requirement would increase to 93.6 MMcf/d. The extant remaining regasifier (93 MMcf/d send-out capacity) at the EcoEléctrica LNG Import Terminal could satisfy these needs if a pipeline were to be built from the import terminal to the north, either directly or routed via Aguirre.

#### 7.1.2.9 Land-based (onshore) LNG at San Juan with pipeline to Palo Seco

As mentioned previously, the Galway study reached the conclusion that among the 14 options, the most feasible is land-based (onshore) LNG storage and vaporization at a warehouse site adjacent to San Juan power station on its east side and with standards scale LNG carrier delivery directly to onshore tanks. The best option considered was immediately adjacent to San Juan plant in a warehouse district to the east. A second viable option for an onshore storage and vaporization system was considered further to the east of San Juan plant at a location known as Pier 15/16. However, Siemens notes that an onshore facility is likely to be costlier than an FSRU or FSU option. Furthermore, the Galway study did not consider small- to medium-scale LNG carriers as a possible supply option for direct delivery into San Juan harbor. Instead the Galway study considered smaller-scale shuttle tankers being loaded from LNG ships via ship-to-ship transfer in the area of Guayanilla Canyon on the protected south side of Puerto Rico).

Looking at the generation plants that an onshore LNG terminal would supply, it is expected that current generating units using residual fuel oil at San Juan and Palo Seco will be replaced, retired or limited in use in several years to achieve MATS compliance. The replacement generation for these sites will be capable of natural gas and diesel firing. A

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[46] https://www.epa.gov/sites/production/files/2015-08/documents/lng_regulatory_roadmap.pdf

northern LNG terminal could provide significant cost savings relative to diesel fuel. Based on input from PREPA, a land-based (onshore) LNG terminal at San Juan would require an estimated $492 million in capital costs (2018$) including $457 million for the LNG terminal and $35 million for the pipeline from San Juan to Palo Seco. Note that the pipeline costs are lower than in the 2015 IRP due to the assumed use of an existing oil pipeline right-of-way to construct the 4.2 mile pipeline to Palo Seco. Annual fixed operating costs (OPEX) are conservatively assumed to be 5.2% of total capital expenditures (CAPEX), whereas the general rule of thumb for OPEX is 2.5%-3% of CAPEX. The earliest online date would be July 1, 2022.

#### 7.1.2.10 Ship-Based LNG to Mayagüez (west) and/or Yabucoa (east)

Mayagüez is located on the western side of the island, where PREPA has a 4x50 MW (total of 200 MW) diesel-fired generation. Yabucoa is located on the eastern side of the island, where PREPA has two combustion turbines (2x21 MW) also burning diesel. Siemens is investigating the possibility of one or more floating LNG and storage import terminals that could service the power generation plants at Mayagüez, Yabucoa, or both locations. The existing generation could be complemented with up to 300 MW of gas-fired generation, which would require a natural gas fuel supply solution. The proposed solution would most likely be a ship-based (offshore) FSRU option, similar to what could be installed in the San Juan port for LNG supply to San Juan plant and/or Palo Seco plant and with similar capital expenditure and operating expenditure estimates. Accordingly, Siemens estimates the CAPEX for ship-based LNG delivery to Mayagüez and/or Yabucoa to be $185 million and the annual OPEX to be $9.6 million.

#### 7.1.2.11 LNG/CNG Delivery via ISO Containers to Northern Power Plants

Alternatively, natural gas supply to the northern side of the island could be delivered in the form of LNG or CNG using ISO containers. This mode of LNG or CNG transport uses standard, intermodal, 40 foot ISO containers that can be marine-shipped, trucked, handled, and stored much like a standard 40 foot cargo container. Each 40 foot LNG ISO container is an independent storage system with about an 858 MMBtu capacity for up to a 90 day storage period. Each 40 foot CNG ISO container has a capacity of about 267 MMBtu.

There are numerous LNG and CNG suppliers available in the U.S. and internationally that utilize these systems. LNG and CNG ISO containers potentially could be delivered to the San Juan port and unloaded using standard container handling equipment, trucked to San Juan / Palo Seco sites using existing container tractor-trailers, and then directly connected to a common regasification system feeding the fuel delivery piping of individual units. While this delivery method is generally more costly than bulk supply for large volumes of LNG, it could be a cost-effective option to fuel the new small CCs at Palo Seco. In addition, the LNG or CNG ISO containers could provide an interim solution that could deliver fuel to the San Juan Units 5 and 6 CCs while long-term delivery infrastructure is being permitted and constructed.

The San Juan port that is directly adjacent to the San Juan power plant has a large capacity container terminal that could potentially support daily full and empty LNG container movements. About 50 of these containers per day could be loaded onto trucks for transport to

Palo Seco, with empty containers carried back on the return trip. LNG or CNG containers[47] also could be used to deliver natural gas to peaking sites such as Cambalache and Mayagüez. The practicality of delivering the large volume of LNG or especially CNG required for both Palo Seco CCs and San Juan CCs has been assessed.

The same March 2017 Siemens PTI fuel delivery assessment further developed this analysis of LNG / CNG to northern power plants and separately to Aguirre, estimating that containerized LNG deliveries would require 40 ISO containers per day while CNG deliveries would require 126 containers per day to meet project demand at the two northern power plants (for Aguirre, it would be 193 and 617 containers, respectively). As a result, the study concluded that small-scale LNG / CNG delivery either as a bridge fuel or long-term solution is not feasible given that small-scale LNG / CNG delivery costs to San Juan are prohibitively high and operational risks are too great. The study recommended further evaluation of bulk LNG delivery to San Juan and Palo Seco with onsite tank storage (the same conclusion as the previously cited Galway study). Siemens does not recommend small-scale LNG or CNG delivered via ISO containers as a viable solution for this IRP.

#### 7.1.2.12 **Pipeline Supply from EcoEléctrica LNG Import Terminal**

An alternative to a northern LNG / CNG terminal and potentially also to the AOGP could be a natural gas pipeline that delivers natural gas from the existing EcoEléctrica LNG Import Terminal to the San Juan and Palo Seco plants in San Juan. Such a pipeline could be constructed to have one segment along the southern coast of Puerto Rico to serve the Aguirre power plant (creating an alternative to the AOGP plant) before a second segment turns north toward the San Juan plant with a lateral to Palo Seco. Alternatively, a pipeline could be routed to go directly from the EcoEléctrica LNG Import Terminal to San Juan, which would not require additional regasification apart from bringing online the extant remaining gasifier. Any such project must consider the pipelines costs as well as permitting feasibility.

A past 2008n proposal to bring natural gas to the north (Gasoducto del Norte or GdN, also known as Via Verde) by pipeline from EcoEléctrica LNG Import Terminal encountered significant public opposition during permitting and was canceled. Several pipeline routes were considered but the option designated as preferred was generally north from EcoEléctrica to Arecibo and then east to Palo Seco/San Juan. Laterals were considered to serve the Cambalache and Mayagüez peaking units. A South-North pipeline from Aguirre to San Juan area could be more practical than the preferred western routes considered earlier. A natural gas pipeline between Costa Sur and Aguirre has been attempted in the past (Gasoducto del Sur) and is technically feasible. Section 2.6.1 of the 2008 GdN study referenced above identified two possible routes from Aguirre to the north. These routes' lengths were about 50 miles each, with about 600 acres of right-of-way including up to 64 acres of wetlands impact. One of these routes is close to an already-disturbed corridor for Route 52 and had the lower wetlands impact. A pipeline route along the south coast, from Costa Sur to Aguirre, generally

[47] LNG tank trailers also can be used to transport LNG. With necessary permitting and commercial arrangements, trailer loading facilities could be located at any site with bulk LNG storage, such as EcoEléctrica, or at an onshore LNG terminal at San Juan.

is perceived as more practical and having less environmental and public impact than a pipeline along the northern coast. This portion of a system to transport natural gas from EcoEléctrica to the north may be less controversial than the South-North section.

The 2008 GdN report provided estimated costs for such a pipeline, confirmed by more recent estimates performed by Siemens. The Aguirre-San Juan overland route (not the route along Route 52) was about 52 miles long before adjustment for terrain. A 20 inch pipeline size was assumed for a flow volume of 249 MMcf/d. Costs included route surveying, engineering, project management, inspection, materials, construction and restoration. The cost of this line in mid-2008 U.S. dollars was $206 million, or $238 million in 2018 dollars. This comports well with Siemens' current estimate of a cost of $221 million for this South-North pipeline route, although Siemens estimated that a 16" pipe is sufficient to supply the combined 93.6 MMcf/d demand from San Juan and Palo Seco after conversion to natural gas. Other assumptions used by Siemens include a distance of 49 miles and $4.5 million per mile (2018$). Considering that a south coast pipeline (Costa Sur to Aguirre) has been budgeted in the past, PREPA should have reasonably accurate estimates of cost. The pipeline nominal length from Costa Sur to Aguirre is 42 miles. Using a cost of about $5.1 million per mile (2018$) for 20" pipeline, which would carry 249 MMcf/d or sufficient gas volumes to supply Aguirre, San Juan and Palo Seco, this would cost approximately $214 million. The total cost for a pipeline from EcoEléctrica LNG Import Terminal to Aguirre to San Juan is estimated to be $470 million, including $35 million for a short 4.2 mile pipeline to the Palo Seco plant.

Although a pipeline route has been attempted in the past, but was halted due to public opposition, the aftermath of the storms represents an important inflection point in Puerto Rico's history. There is a potential window of opportunity to re-evaluate the pipeline option during this time of rebuilding. It is recommended that an updated cost and routing analysis be conducted on possible pipeline supply options to Aguirre and San Juan/Palo Seco.

#### 7.1.2.13 **Alternative Fuels**

PREPA received an unsolicited proposal from Puma Energy Caribe (Puma) and Aggreko in August 2017, which was approved for further consideration in October 2017. The proposal was for a 100 MW power generation solution using LPG (liquefied petroleum gas, which is mostly propane) in Bayamón, Puerto Rico (just outside of San Juan). The proposal would satisfy several important criteria that PREPA is looking for in power generation solutions, including a location in the north near load centers, a public/private partnership (P3) that would require no capital expenditure from PREPA and conforms to PREPA's Fiscal Plan Part VII (Investment Program) requiring that P3 generation in year 2026 be approximately 30% of the total system generation, and a turnkey approach that can be implemented quickly. The proposed solution would also have a relatively low heat rate (8,900 Btu/kWh) to provide efficient power generation, burn relatively clean LPG fuel to help meet MATS standards (and which is typically cheaper than diesel or residual fuel oil), have a fast start time of two minutes to 100% capacity, and be strategically located near existing Puma facilities where no additional LPG storage would be needed beyond the existing 100,000 barrels of LPG storage.

Siemens believes that LPG fuel will remain cost-competitive compared to diesel and residual fuel oil. This aspect, together with the other attributed enumerated above, lead to the conclusion that this project is worthy of further exploration as one solution among many to develop new sources of power generation. The PUMA proposal that Siemens reviewed did not include a pricing formula or forecast, so an LPG price forecast was developed using the historical price relationship with crude oil. This forecast is provided in the following forecast section.

A coal price forecast is also provided for fuel supply costs to the AES plant, based on Siemens' 2018 spring outlook and benchmarked to the EIA AEO 2018 forecast and others.

#### 7.1.2.14 No New Natural Gas Infrastructure

If additional natural gas infrastructure and supplies cannot be developed, one option is to maintain the status quo. This option ignores the potential fuel cost savings that could come from natural gas supply and may also increase the challenges with meeting MATS requirements. This option should also be considered in the IRP planning process, pending the available generation options review.

Other potential liquid fuels such as propane, ethane and biofuels could be considered. Over the past two years, propane has been about 2.5 times as costly as natural gas on an equivalent MMBtu basis. Propane when burned for power generation emits about 16% more carbon dioxide than natural gas but is cleaner than residual fuel oil. While increases in propane and ethane production associated with U.S. shale gas production have led to recent market imbalances that have depressed the prices of these products, prices have begun to rise again as the market recovers. Siemens believes that in the long-term, propane and ethane prices will maintain higher levels relative to diesel and certainly with respect to natural gas. So, while there may be some interim opportunities to take advantage of such fuels, propane, ethane, and biofuels are not expected to be long-term cost-effective solutions.

#### 7.1.2.15 Fuel Infrastructure Scenarios Comparison

As discussed previously, there are a broad range of fuel infrastructure scenarios. These include the following, in no particular order:

- Aguirre Offshore Gas Port (AOGP)
- Land-based (onshore) LNG to the North
- Ship-based (offshore) LNG to the North
- Ship-based (offshore) LNG at Mayagüez (west)
- Ship-based (offshore) LNG at Yabucoa (east)
- Small-scale LNG and CNG to the North and South
- Additional Regasification Capacity at EcoEléctrica LNG Import Terminal with a Costa Sur-Aguirre-San Juan Pipeline
- No New Gas Infrastructure

Each fuel infrastructure scenario should be evaluated, at a minimum, on the broad categories of capital cost requirements, estimated operational costs, resiliency and reliability, environmental impact, and public concerns. Many other considerations are embedded within these categories, including technical complexity, permitting process, fuel supply options, regulatory compliance, commercial partnerships, etc. The following table provides a summary evaluation of these infrastructure options.

### Exhibit 7-4. Fuel Infrastructure Options Assessment

| Fuel Infrastructure Scenario | Capital & Operating Costs (Million 2018$) | Est. Vol. Required (MMcf/d) | Resiliency & Reliability | Environmental Impact | Public Concerns | Fatal Flaw |
|---|---|---|---|---|---|---|
| Aguirre Offshore GasPort | GasPort=$403 - Annual O&M=$81.5 (+fuel) | (1,076 MW) - (7,500 Btu/kWh) - 155 MMcf/d | Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to AOGP or south-to-north power transmission. | Carbon and other emissions would be reduced with AOGP and conversion at Aguirre to gas-fired generation. | Infrastructure would be located away from population but concerns over cost and stranded fossil fuel plant. | N/A |
| Ship-based LNG (FSRU) at San Juan Port with pipeline to both plants | FSRU=$185 - Pipeline to Palo Seco=$35 - Annual O&M=$11.4 (+fuel) | (650 MW) - (7,500 Btu/kWh) - 93.6 MMcf/d | Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to FSRU. | Carbon and other emissions would be reduced with FSRU and gas-fired generation. Increased vessel traffic could impact coastal marine life. | Harborview would be impacted by FSRU and potential damage to marine environment from pipeline. | N/A |
| Ship-based LNG at MayagüezMayagüez (west) | FSRU=$185 - Annual O&M=$9.6 (+fuel) | (300 MW) - (7,500 Btu/kWh) - 43.2 | Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to FSRU. | Carbon and other emissions would be reduced with FSRU and gas-fired generation. Increased vessel traffic could impact coastal marine life. | Infrastructure would be located away from population but concerns over cost and stranded fossil fuel plant. | N/A |

| Fuel Infrastructure Scenario | Capital & Operating Costs (Million 2018$) | Est. Vol. Required (MMcf/d) | Resiliency & Reliability | Environmental Impact | Public Concerns | Fatal Flaw |
|---|---|---|---|---|---|---|
| | | MMcf/d | | | | |
| Ship-based LNG at Yabucoa (east) | FSRU=$185 - Annual O&M=$9.6 (+fuel) | (300 MW) - (7,500 Btu/kWh) - 43.2 MMcf/d | Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to FSRU. | Carbon and other emissions would be reduced with FSRU and gas-fired generation. Increased vessel traffic could impact coastal marine life. | Infrastructure would be located away from population but concerns over cost and stranded fossil fuel plant. | N/A |
| Small-scale LNG (or CNG) Solutions at San Juan Port and/or Aguirre | CAPEX=$540 - Annual O&M= $45-81 | 50-249 MMcf/d | Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to small-scale LNG port. | Carbon and other emissions would be reduced with LNG. Increased vessel traffic could impact coastal marine life. | Concerns over significantly increased vessel traffic in busy ports and potential damage to marine environment. | Unfeasible logistics for large volume customers |
| Land-based LNG at San Juan Port with pipeline to Palo Seco | Onshore LNG Terminal=$457 - Pipeline=$35 - Annual O&M=$25.6 | 93.6 MMcf/d | Increase reliability from flexibility to burn gas or diesel (currently oil only). Resiliency could be challenged by hurricane damage to onshore LNG port. | Carbon and other emissions would be reduced with LNG. Increased vessel traffic could impact coastal marine life. | Concerns over significantly increased vessel traffic, disruptive pipeline to Palo Seco. | N/A |

| Fuel Infrastructure Scenario | Capital & Operating Costs (Million 2018$) | Est. Vol. Required (MMcf/d) | Resiliency & Reliability | Environmental Impact | Public Concerns | Fatal Flaw |
|---|---|---|---|---|---|---|
| Pipeline from Costa Sur to Aguirre and San Juan (with additional regasification at EcoEléctrica) | Costa Sur to Aguirre Pipe=$184 - Aguirre to San Juan Pipe=$238 - Annual O&M=$40 | 249 MMcf/d | Resiliency and reliability increased by transport via underground pipeline, providing flexibility to burn gas or diesel at converted generation plants. Additional regas capacity provided by private co. | Carbon and other emissions would be reduced with pipeline gas delivery and conversion to gas-fired generation. | Previous attempt to construct Costa Sur to San Juan pipeline was cancelled due to public concerns. | N/A |
| No New Gas Infrastructure | N/A | N/A | Existing generation plants lack flexibility in cleaner fuel choice. Onsite fuel storage more reliable than LNG deliveries susceptible to disruption. | Carbon and other emissions would remain higher than permissible/desired under current regulations. | Leaves space for increased renewables penetration and removes risk of stranded fossil fuel assets. | N/A |

Source: Siemens, PREPA.

For the purposes of this 2018 IRP, there are four key fuel infrastructure options under consideration, which include:

- The land-based LNG at San Juan Port with pipeline to Palo Seco
- The ship-based LNG at Mayagüez (west),
- The ship-based LNG at Yabucoa (east), and
- The ship-based LNG (FSRU) at San Juan Port (supply to San Juan only).

Exhibit 7-5 below provides a summary view of these four infrastructure options together with CAPEX (2018$MM), annual OPEX (2018$MM), maximum daily gas volumes (MMcf/d), maximum generation capacity (MW), CAPEX in $/kW, and annual OPEX in $/kW.

**Exhibit 7-5. Fuel Infrastructure Options Assessment**

| Infrastructure Option | CAPEX ($MM) (2018$) | Annual OPEX ($MM) (2018$) | Max Daily Gas Volume (MMcf/d) | Max Capacity (MW) | Annualized CAPEX ($/kW) (2018$) | Annual OPEX ($/kW) (2018$) | CAPEX + Annual OPEX ($/kW) (2018$) |
|---|---|---|---|---|---|---|---|
| Land-based LNG at San Juan Port with pipeline to Palo Seco | $492 | $25.6 | 93.6 | 650 | $77 | $39 | $116 |
| Ship-based LNG at Mayagüez (west) | $185 | $9.6 | 43.2 | 300 | $63 | $32 | $95 |
| Ship-based LNG at Yabucoa (east) | $185 | $9.6 | 43.2 | 300 | $63 | $32 | $95 |
| Ship-based LNG (FSRU) at San Juan Port (supply to San Juan only) | $185 | $9.6 | 50.4 | 350 | $54 | $27 | $81 |

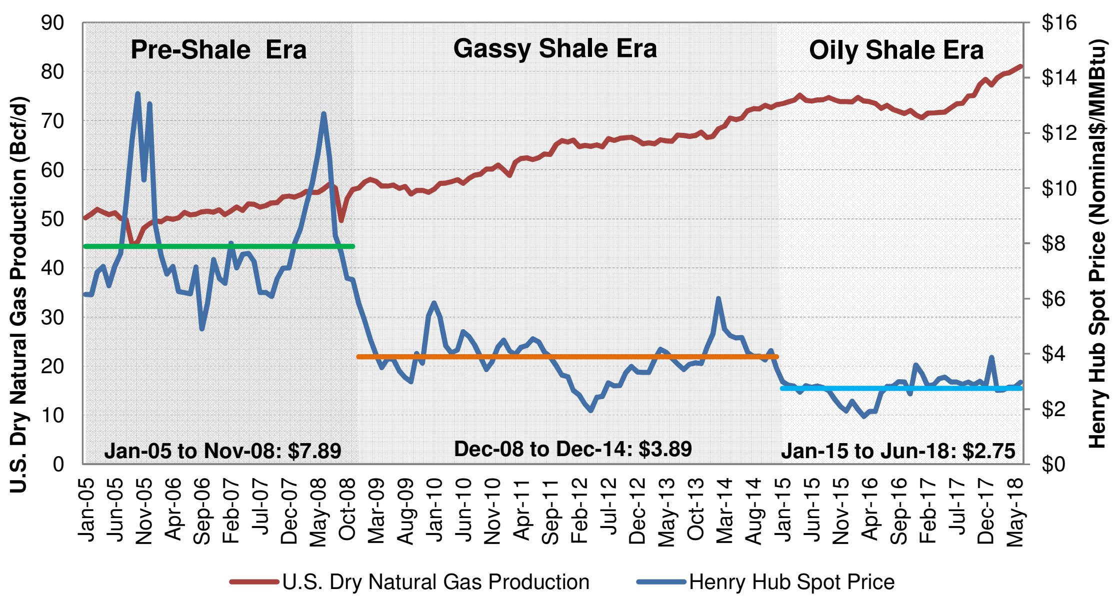
Apart from the No New Gas Infrastructure Scenario, the ship-based LNG (FSRU) at San Juan Port scenario represents the lowest CAPEX and annual OPEX cost. The three feasible LNG to the North scenarios (ship-based LNG, land-based LNG, and pipeline) would support the conversion of the northern plants of San Juan and Palo Seco (currently 1,158 MW) to natural gas, but with very different CAPEX costs depending upon the infrastructure. Ship-based LNG (FSRU) would be the least-cost, followed by pipeline supply from the south, followed by land-based LNG. The Costa Sur to Aguirre to San Juan Pipeline scenario envisions the broader conversion to natural gas of generation plants at Aguirre, San Juan, and Palo Seco with commensurate benefits in terms of lower emissions and lower fuel costs than existing generation. The pipeline scenario would also require upgrades to the EcoEléctrica LNG Import Terminal to supply sufficient fuel to meet this increased demand, but the costs would be borne by the private EcoEléctrica company. Each of these fuel infrastructure scenarios bears merit and also has drawbacks that must be weighed in the context of the larger IRP study. Accordingly, a recommendation for pursuing one of these scenarios is reserved pending the completion of the comprehensive review of PREPA's options using a capacity expansion model that would assess the convenience of installing natural gas generation or converting exiting units as is the case of San Juan 5 & 6 against optimized portfolios that could achieve similar benefits with different sets of resources.

## 7.2 Fuel Price Forecasts

Siemens prepared fuel price forecasts for natural gas at the Henry Hub, crude oil (West Texas Intermediate or WTI), and the oil-derivate products of diesel (No. 2 fuel oil) and residual fuel oil (No. 6 fuel oil with 0.5% sulfur). The Henry Hub benchmark is located in Erath, LA while the WTI benchmark is located in Cushing, OK. The diesel and residual fuel oil forecasts are based on New York Harbor pricing (per the contract terms for Costa Sur). The following sections describe the methodology for preparing these commodity forecasts for the 2018 IRP. Although standard scale LNG deliveries from the mainland U.S. would be difficult under the restrictions of the Jones Act, the following forecasts nevertheless are based on Henry Hub pricing to align with current fuel supply contract terms.

In accordance with the recommendation of the Transformation Advisory Council (TAC), which advocated for the use of a 10-year implied market volatility assumption for oil and natural gas in lieu of the 3-year volatility assumptions used in Siemens' original stochastic price simulations, Siemens has taken into consideration the recommendation for oil price volatility. However, for natural gas price volatility, Siemens feels there is justification for a shorter historical lookback. The pricing graph in Exhibit 7-6 shows how natural gas prices have declined in each of two different shale eras. Price volatility has also declined along with absolute prices. A potential return to higher price oil, which 2018 experienced for nearly the whole year, would help to increase associated gas production and keep additional downward price pressure on natural gas.

**Exhibit 7-6. Pricing Eras of the Shale Revolution**




Sources: Siemens, EIA.

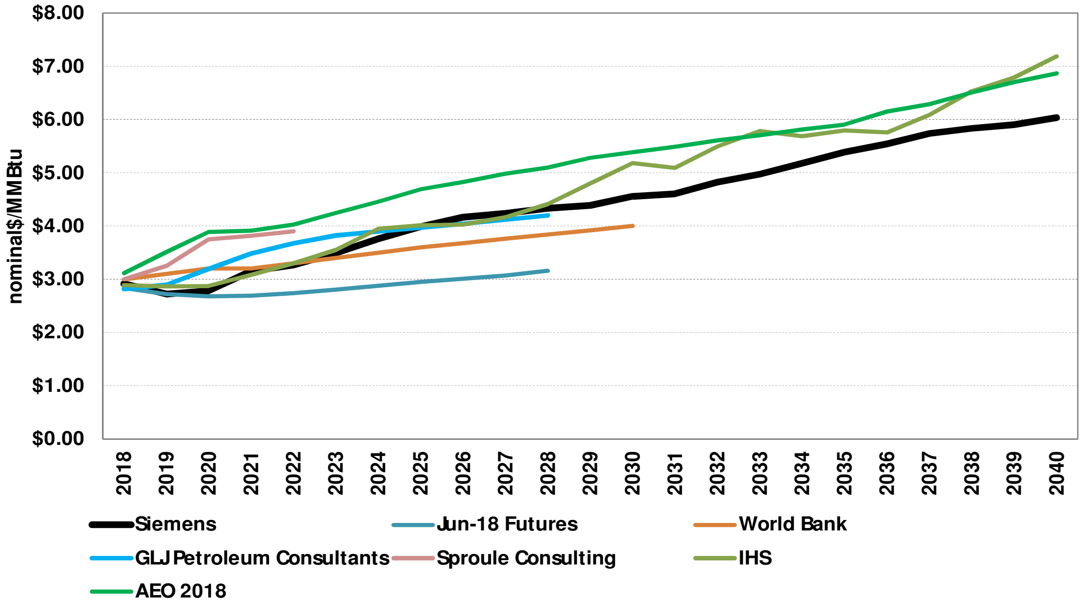
By contrast with natural gas, which is still a regional market, oil is much more a global commodity and its price and volatility have been less affected by U.S. oil shale production than U.S. shale gas. This is an argument for a longer historical lookback when calculating the implied market volatility of oil, so Siemens took the TAC recommendation and recalculated the price distributions using a 10-year implied market volatility assumption. This allowed for the comparison of the 10-year, 5-year, and 3-year implied market volatility, which are 2.04%, 1.85%, and 1.83%, respectively. The result of the 10-year update was a higher short-term outlook but relatively unchanged long-term outlook at the one standard deviation level (84.1$^{st}$ percentile band). Although it is exceedingly rare as a scenario, Siemens uses the two standard deviation level (97.7$^{th}$ percentile band) as a high oil price boundary case, which represents a future in which in only 23 out of 1,000 cases will have higher oil prices. This would see oil prices reach $190/bbl in nominal dollars by the end of the forecast.

### 7.2.1.1 Henry Hub Natural Gas

Siemens develops an independent projection of regional fuel prices, in particular natural gas, crude oil and its derivative products (diesel, fuel oil, LPG, etc.). The natural gas price projections are developed using the GPCM® tool, is described in more detail in the Attachment A, includes the benchmark Henry Hub price hub as well as more than 60 liquid trading hubs across North America. Siemens's Henry Hub forecast incorporates updated assumptions for natural gas demand, supply, and infrastructure and also benchmarks its short-term natural gas forecast to recent market forwards. Forwards are dated from June 2018. These forwards were used explicitly for the first 18 months of the forecast (June-2018 to Nov-2019), then blended into the fundamental forecast over the following 18 months. The first three years of the forwards curve represent the most liquid part of the curve, when trades and volumes are significantly higher than afterward. Exhibit 7-7 below provides a comparison of Siemens' forecast for Henry Hub prices with the AEO 2018 Henry Hub forecast as well as several other forecasts, for reference.

**Exhibit 7-7. Henry Hub Forecast Comparison (nominal$/MMBtu)**

| Forecaster | Siemens | AEO 2018 | Jun-18 Futures | World Bank | GLJ Petroleum Consultants | Sproule Consulting | IHS |
|---|---|---|---|---|---|---|---|
| Unit | nom$/ MMBtu | nom$/ MMBtu | nom$/ MMBtu | nom$/ MMBtu | nom$/ MMBtu | nom$/ MMBtu | nom$/ MMBtu |
| Date | Jun-18 | Feb-18 | Jun-18 | Apr-18 | Apr-18 | May-18 | Feb-18 |
| 2018 | 2.91 | 3.11 | 2.84 | 3.00 | 2.82 | 3.00 | 2.89 |
| 2019 | 2.72 | 3.51 | 2.72 | 3.10 | 2.90 | 3.25 | 2.87 |
| 2020 | 2.79 | 3.89 | 2.68 | 3.20 | 3.20 | 3.75 | 2.88 |
| 2021 | 3.16 | 3.92 | 2.69 | 3.20 | 3.48 | 3.82 | 3.09 |
| 2022 | 3.27 | 4.03 | 2.74 | 3.30 | 3.67 | 3.90 | 3.30 |
| 2023 | 3.49 | 4.25 | 2.81 | 3.40 | 3.82 | | 3.55 |
| 2024 | 3.76 | 4.46 | 2.88 | 3.50 | 3.90 | | 3.95 |
| 2025 | 3.98 | 4.69 | 2.95 | 3.60 | 3.97 | | 4.01 |
| 2026 | 4.16 | 4.83 | 3.01 | 3.68 | 4.04 | | 4.03 |
| 2027 | 4.24 | 4.98 | 3.07 | 3.76 | 4.12 | | 4.16 |
| 2028 | 4.34 | 5.10 | 3.16 | 3.84 | 4.20 | | 4.41 |
| 2029 | 4.39 | 5.28 | | 3.92 | | | 4.80 |
| 2030 | 4.56 | 5.39 | | 4.00 | | | 5.18 |
| 2031 | 4.61 | 5.49 | | | | | 5.09 |
| 2032 | 4.82 | 5.61 | | | | | 5.50 |
| 2033 | 4.97 | 5.71 | | | | | 5.78 |
| 2034 | 5.18 | 5.81 | | | | | 5.69 |
| 2035 | 5.39 | 5.91 | | | | | 5.79 |
| 2036 | 5.54 | 6.15 | | | | | 5.76 |
| 2037 | 5.74 | 6.29 | | | | | 6.09 |
| 2038 | 5.84 | 6.51 | | | | | 6.53 |
| 2039 | 5.90 | 6.70 | | | | | 6.79 |
| 2040 | 6.03 | 6.87 | | | | | 7.19 |




Source: Siemens, various sources.

Siemens prepared a delivered natural gas price forecast for the Costa Sur, San Juan, and Aguirre generation plants, as well as the Mayagüez and Yabucoa plants, each of which can or could receive natural gas as a fuel supply and which represent the four sides of the island. In the case of Costa Sur, which is currently under a fuel supply contract[48], the adders are already known and applied to derive a delivered natural gas forecast price. In the case of Aguirre and San Juan, the P2 pricing formula from the San Juan fuel supply contract was used, which is equal to 115% of Henry Hub plus $5.95/MMBtu. The Mayagüez and Yabucoa plants are assumed to have a similar LNG price structure as San Juan.

#### 7.2.1.2 EIA Annual Energy Outlook 2018

The U.S. Department of Energy's (DOE) EIA Annual Energy Outlook (AEO) 2018[49], issued February 2018, provides their latest forecast for natural gas prices at the benchmark Henry Hub based on the key fundamentals of supply, demand, and infrastructure. The AEO 2018 Reference case forecasts that natural gas production growth will outpace consumption growth in every year to the forecast horizon of 2050. This driver, together with an estimated increase in lower-cost resources in the Permian and Appalachian basins, has resulted in Henry Hub prices that are 14% lower this year than last year's AEO. In the Permian basin, associated natural gas production from tight oil production is supported by relatively high oil prices. In the Appalachian basin, the Marcellus and Utica plays (located in Pennsylvania, Ohio, and West Virginia) continue to drive most U.S. production growth as they have over the last several years due to the substantial resource in-place with low production costs proximate to key demand centers in the U.S. Northeast. On the demand side, industrial and power generation demand together drive natural gas consumption growth to 2050. Growth in

[48] http://energia.pr.gov/wp-content/uploads/2018/08/Memorial-Explicativo-R-del-S-219-CEPR.pdf

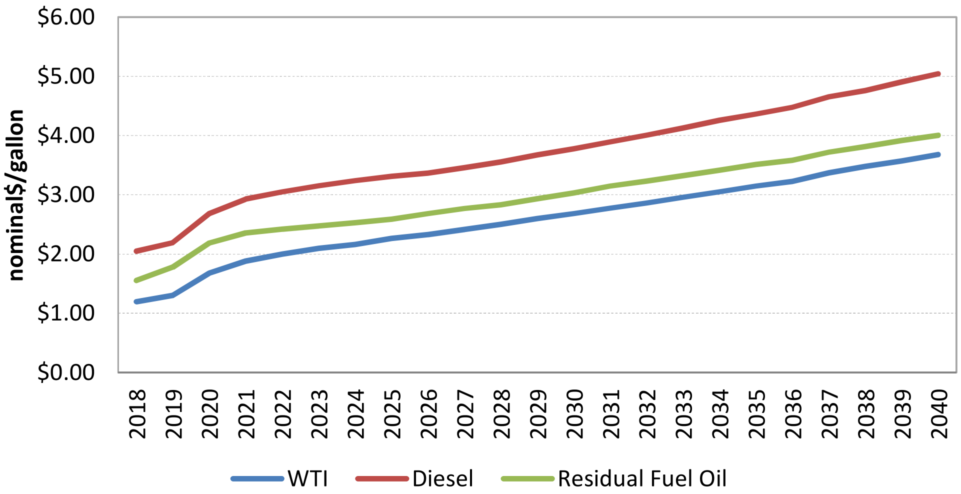
[49] https://www.eia.gov/outlooks/aeo/

exports via liquefied natural gas (LNG) facilities is strong through 2030 and pipeline exports to Mexico through 2025.

The AEO 2018 forecast for WTI, distillate fuel oil (diesel), and residual fuel oil is provided in Exhibit 7-8 below.

**Exhibit 7-8. AEO 2018 Price Outlook (nominal$/gallon)**

| Product | WTI | Diesel | RFO |
|---|---|---|---|
| Unit | nom$/ gallon | nom$/ gallon | nom$/ gallon |
| 2018 | 1.20 | 2.05 | 1.56 |
| 2019 | 1.30 | 2.19 | 1.78 |
| 2020 | 1.68 | 2.68 | 2.18 |
| 2021 | 1.88 | 2.93 | 2.36 |
| 2022 | 2.00 | 3.05 | 2.42 |
| 2023 | 2.09 | 3.15 | 2.47 |
| 2024 | 2.16 | 3.24 | 2.53 |
| 2025 | 2.26 | 3.31 | 2.59 |
| 2026 | 2.33 | 3.37 | 2.68 |
| 2027 | 2.42 | 3.46 | 2.77 |
| 2028 | 2.50 | 3.55 | 2.83 |
| 2029 | 2.60 | 3.68 | 2.93 |
| 2030 | 2.68 | 3.77 | 3.03 |
| 2031 | 2.77 | 3.89 | 3.14 |
| 2032 | 2.86 | 4.00 | 3.23 |
| 2033 | 2.96 | 4.13 | 3.32 |
| 2034 | 3.05 | 4.26 | 3.41 |
| 2035 | 3.15 | 4.36 | 3.51 |
| 2036 | 3.23 | 4.47 | 3.58 |
| 2037 | 3.37 | 4.66 | 3.72 |
| 2038 | 3.48 | 4.76 | 3.81 |
| 2039 | 3.57 | 4.90 | 3.92 |
| 2040 | 3.68 | 5.04 | 4.01 |




Source: EIA

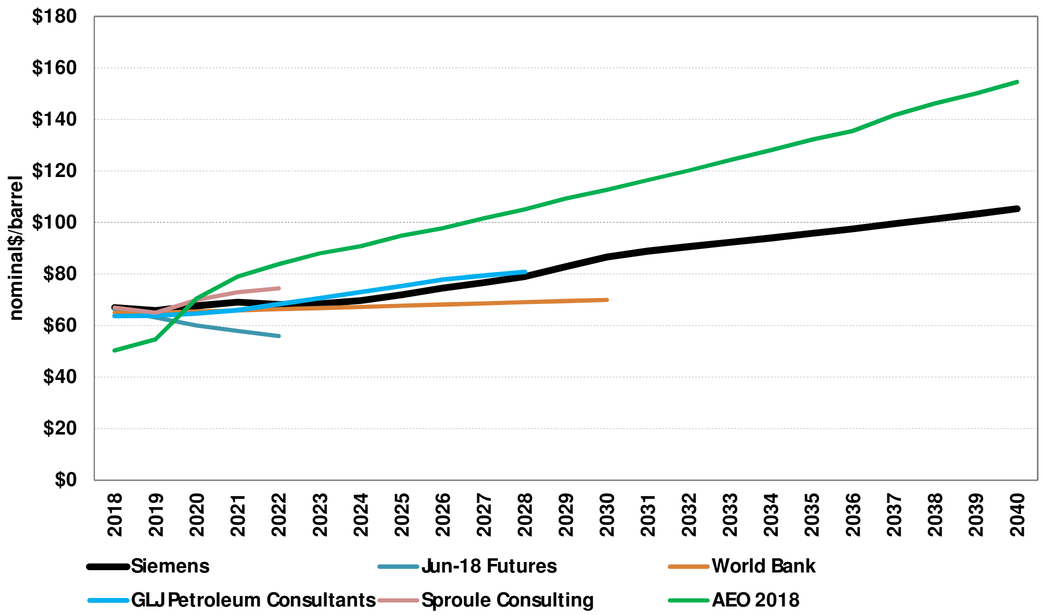
### 7.2.1.3 West Texas Intermediate (WTI) Crude Oil

Benchmark WTI oil price forecasts are developed exogenously by comparing and averaging price outlooks from a variety of reputable sources (EIA, IEA, etc.). A comparison of Siemens's WTI price outlook together with other outlooks is compiled in Exhibit 7-9.

**Exhibit 7-9. WTI Forecast Comparison (nominal$/barrel)**

| Forecaster | Siemens | AEO 2018 | Jun-18 Futures | World Bank | GLJ Petroleum Consultants | Sproule Consulting |
|---|---|---|---|---|---|---|
| Unit | nom$/ barrel | nom$/ barrel | nom$/ barrel | nom$/ barrel | nom$/ barrel | nom$/ barrel |
| Date | Jun-18 | Feb-18 | Jun-18 | Apr-18 | Apr-18 | May-18 |
| 2018 | 67.02 | 50.31 | 66.31 | 65.00 | 63.67 | 67.00 |
| 2019 | 65.82 | 54.67 | 63.16 | 65.00 | 63.86 | 65.00 |
| 2020 | 67.65 | 70.48 | 59.99 | 65.40 | 64.69 | 70.00 |
| 2021 | 69.10 | 78.98 | 57.93 | 65.90 | 65.99 | 73.00 |
| 2022 | 68.20 | 83.85 | 55.98 | 66.30 | 68.33 | 74.46 |
| 2023 | 68.49 | 87.97 | | 66.80 | 70.62 | |
| 2024 | 69.61 | 90.78 | | 67.20 | 73.01 | |
| 2025 | 71.94 | 94.96 | | 67.70 | 75.38 | |
| 2026 | 74.57 | 97.80 | | 68.16 | 77.79 | |
| 2027 | 76.65 | 101.57 | | 68.62 | 79.31 | |
| 2028 | 79.05 | 105.06 | | 69.08 | 80.77 | |
| 2029 | 82.86 | 109.30 | | 69.54 | | |
| 2030 | 86.65 | 112.70 | | 70.00 | | |
| 2031 | 88.89 | 116.46 | | | | |
| 2032 | 90.59 | 120.22 | | | | |
| 2033 | 92.30 | 124.19 | | | | |
| 2034 | 94.02 | 128.00 | | | | |

| Forecaster | Siemens | AEO 2018 | Jun-18 Futures | World Bank | GLJ Petroleum Consultants | Sproule Consulting |
|---|---|---|---|---|---|---|
| Unit | nom$/ barrel | nom$/ barrel | nom$/ barrel | nom$/ barrel | nom$/ barrel | nom$/ barrel |
| Date | Jun-18 | Feb-18 | Jun-18 | Apr-18 | Apr-18 | May-18 |
| 2035 | 95.79 | 132.13 | | | | |
| 2036 | 97.56 | 135.49 | | | | |
| 2037 | 99.41 | 141.64 | | | | |
| 2038 | 101.40 | 146.12 | | | | |
| 2039 | 103.31 | 150.07 | | | | |
| 2040 | 105.28 | 154.52 | | | | |




Source: Siemens, various sources.

### 7.2.1.4 Columbia Coal

Coal sourced from Columbia is forecasted based on Siemens' 2018 spring outlook for Illinois Basin (ILB) coal together with the historical relationship of Columbia coal prices to ILB coal prices. Note that the Exhibits below do not include a flat $10/ton adder for transportation, but this is added to the delivered fuel price for the AES plant that can be found below.

**Exhibit 7-10 Columbia Coal Mine Mouth Price Forecast (nominal$/ton)**

| Unit | nom$/ ton |
|---|---|
| **Date** | **Jul-18** |
| 2018 | 69.43 |
| 2019 | 62.24 |
| 2020 | 58.76 |
| 2021 | 59.02 |
| 2022 | 58.02 |
| 2023 | 58.41 |
| 2024 | 57.69 |
| 2025 | 58.51 |
| 2026 | 59.61 |
| 2027 | 60.73 |
| 2028 | 61.88 |
| 2029 | 63.05 |
| 2030 | 64.24 |
| 2031 | 65.46 |
| 2032 | 66.69 |
| 2033 | 67.95 |
| 2034 | 69.24 |
| 2035 | 70.55 |
| 2036 | 71.89 |
| 2037 | 73.28 |
| 2038 | 74.71 |
| 2039 | 76.17 |
| 2040 | 77.66 |

### 7.2.1.5 Forecast Delivered Fuel Prices at Key Power Plants

The tables below provide Siemens' outlook for delivered fuel prices to the four sides of Puerto Rico (Aguirre, San Juan / Palo Seco, Costa Sur, EcoEléctrica, Mayagüez, and Yabucoa). The forecasts are built from Siemens' base commodity prices for natural gas and crude oil prices, which are then adapted to diesel, residual fuel oil, and LPG based on a historical regression analysis of the relationship between these petroleum products and WTI prices. Finally, cost adders are applied to the base commodity prices to derive delivered fuel prices. The adders were derived from current contractual obligations as provided by PREPA's Fuels Office. Delivered coal and LPG fuel prices are also included below.

**Exhibit 7-11. Delivered Fuels Price Forecasts (including Stochastics) to Aguirre (Nominal$/MMBtu)**

| Plant | Aguirre | Aguirre | Aguirre | Aguirre | Aguirre | Aguirre | Aguirre | Aguirre | Aguirre |
|---|---|---|---|---|---|---|---|---|---|
| Year \ Unit | Natural Gas | Gas @ -1SD | Gas @ +1SD | Diesel | Diesel @ -1SD | Diesel @ +2SD | RFO | RFO @ -1SD | RFO @ +2SD |
| 2018 | 7.70 | 7.53 | 7.65 | 16.44 | 16.18 | 16.60 | 11.48 | 11.26 | 11.61 |
| 2019 | 7.48 | 7.14 | 7.52 | 16.18 | 15.29 | 16.81 | 11.26 | 10.53 | 11.79 |
| 2020 | 7.56 | 7.00 | 7.77 | 16.62 | 15.13 | 18.16 | 11.64 | 10.40 | 12.91 |
| 2021 | 7.99 | 7.17 | 8.46 | 16.98 | 14.58 | 19.79 | 11.94 | 9.96 | 14.27 |

| Plant | Aguirre | Aguirre | Aguirre | Aguirre | Aguirre | Aguirre | Aguirre | Aguirre | Aguirre |
|---|---|---|---|---|---|---|---|---|---|
| Year \ Unit | Natural Gas | Gas @ -1SD | Gas @ +1SD | Diesel | Diesel @ -1SD | Diesel @ +2SD | RFO | RFO @ -1SD | RFO @ +2SD |
| 2022 | 8.11 | 7.01 | 8.97 | 16.79 | 13.73 | 21.45 | 11.79 | 9.26 | 15.65 |
| 2023 | 8.37 | 6.75 | 9.81 | 16.88 | 12.95 | 24.57 | 11.87 | 8.62 | 18.24 |
| 2024 | 8.67 | 6.96 | 10.51 | 17.16 | 12.48 | 29.75 | 12.11 | 8.23 | 22.53 |
| 2025 | 8.93 | 7.17 | 10.63 | 17.72 | 12.57 | 31.58 | 12.57 | 8.32 | 24.05 |
| 2026 | 9.14 | 7.21 | 11.07 | 18.35 | 13.07 | 32.75 | 13.11 | 8.73 | 25.03 |
| 2027 | 9.23 | 7.31 | 11.10 | 18.84 | 13.37 | 32.72 | 13.52 | 8.99 | 25.01 |
| 2028 | 9.34 | 7.40 | 11.27 | 19.43 | 13.67 | 34.00 | 14.01 | 9.24 | 26.07 |
| 2029 | 9.40 | 7.36 | 11.37 | 20.33 | 14.22 | 35.49 | 14.76 | 9.70 | 27.31 |
| 2030 | 9.59 | 7.50 | 11.66 | 21.21 | 14.65 | 37.87 | 15.50 | 10.07 | 29.29 |
| 2031 | 9.65 | 7.25 | 11.80 | 21.76 | 14.98 | 38.74 | 15.96 | 10.35 | 30.01 |
| 2032 | 9.90 | 7.45 | 12.13 | 22.17 | 15.20 | 40.07 | 16.31 | 10.54 | 31.12 |
| 2033 | 10.07 | 7.60 | 12.32 | 22.59 | 15.54 | 40.55 | 16.66 | 10.82 | 31.53 |
| 2034 | 10.31 | 7.64 | 12.95 | 23.02 | 15.74 | 42.21 | 17.02 | 11.00 | 32.91 |
| 2035 | 10.55 | 7.88 | 13.25 | 23.45 | 15.71 | 42.99 | 17.39 | 10.98 | 33.56 |
| 2036 | 10.73 | 7.82 | 13.53 | 23.89 | 16.48 | 43.27 | 17.76 | 11.63 | 33.80 |
| 2037 | 10.96 | 8.14 | 13.85 | 24.35 | 16.79 | 44.11 | 18.15 | 11.89 | 34.51 |
| 2038 | 11.06 | 8.17 | 13.76 | 24.83 | 17.06 | 45.60 | 18.55 | 12.12 | 35.75 |
| 2039 | 11.15 | 8.00 | 13.76 | 25.31 | 17.24 | 46.00 | 18.96 | 12.28 | 36.09 |
| 2040 | 11.30 | 8.09 | 13.96 | 25.80 | 17.66 | 47.57 | 19.37 | 12.64 | 37.39 |

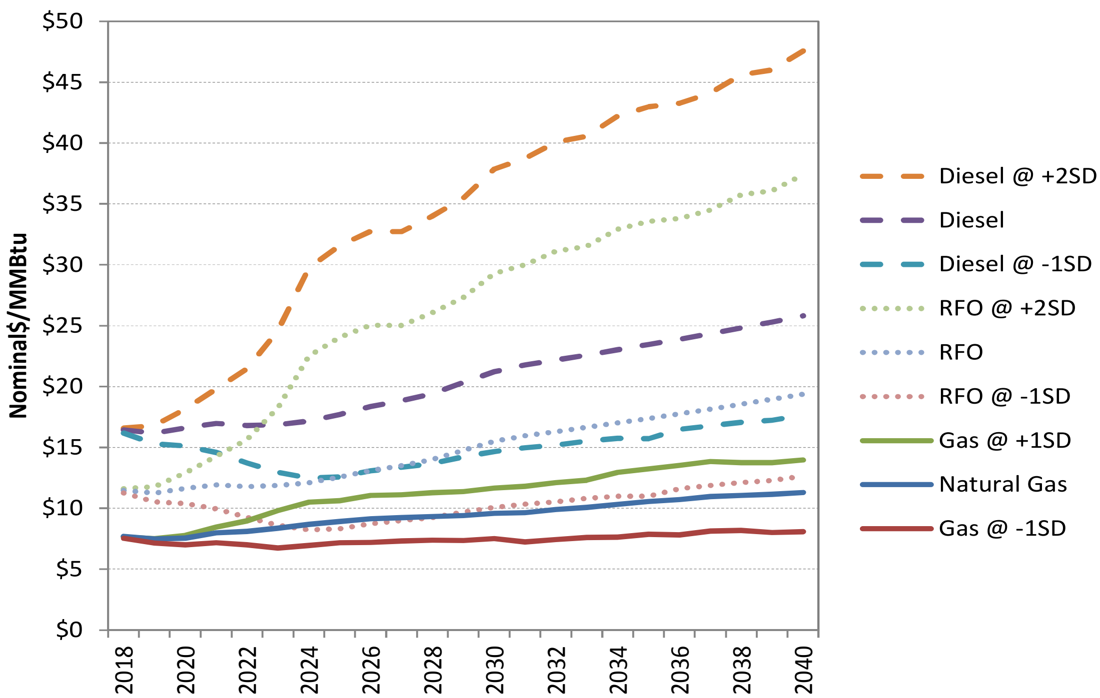
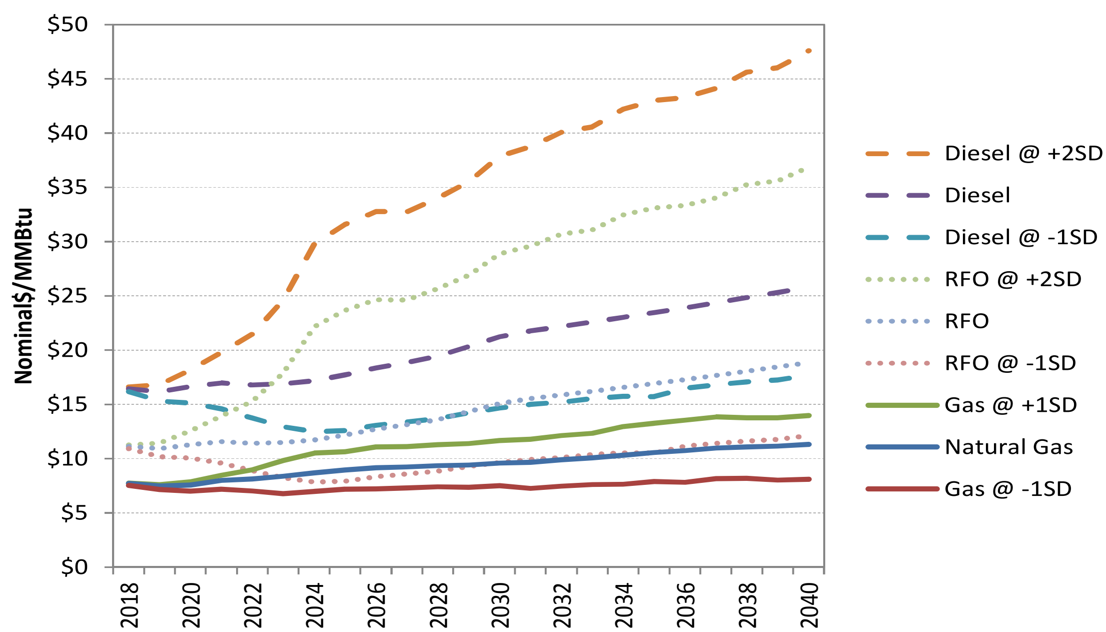


**Exhibit 7-12. Delivered Fuels Price Forecast to San Juan / Palo Seco / Mayagüez / Yabucoa (Nominal$/MMBtu)**

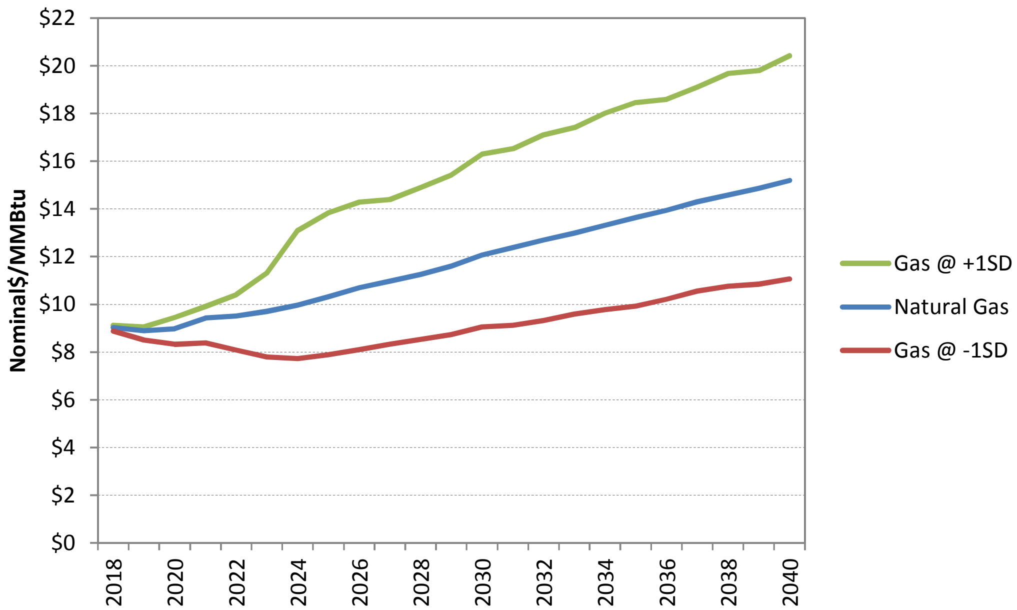
| Plant | SJ-PS-M-Y | SJ-PS-M-Y | SJ-PS-M-Y | SJ-PS-M-Y | SJ-PS-M-Y | SJ-PS-M-Y | SJ-PS-M-Y | SJ-PS-M-Y | SJ-PS-M-Y |
|---|---|---|---|---|---|---|---|---|---|
| Year \ Unit | Natural Gas | Gas @ -1SD | Gas @ +1SD | Diesel | Diesel @ -1SD | Diesel @ +2SD | RFO | RFO @ -1SD | RFO @ +2SD |
| 2018 | 7.70 | 7.53 | 7.75 | 16.44 | 16.18 | 16.60 | 11.13 | 10.91 | 11.26 |
| 2019 | 7.48 | 7.14 | 7.62 | 16.18 | 15.29 | 16.81 | 10.91 | 10.17 | 11.43 |
| 2020 | 7.56 | 7.00 | 7.87 | 16.62 | 15.13 | 18.16 | 11.27 | 10.04 | 12.55 |
| 2021 | 7.99 | 7.17 | 8.46 | 16.98 | 14.58 | 19.79 | 11.57 | 9.59 | 13.90 |
| 2022 | 8.11 | 7.01 | 8.97 | 16.79 | 13.73 | 21.45 | 11.41 | 8.88 | 15.27 |
| 2023 | 8.37 | 6.75 | 9.81 | 16.88 | 12.95 | 24.57 | 11.49 | 8.23 | 17.85 |
| 2024 | 8.67 | 6.96 | 10.51 | 17.16 | 12.48 | 29.75 | 11.72 | 7.84 | 22.14 |
| 2025 | 8.93 | 7.17 | 10.63 | 17.72 | 12.57 | 31.58 | 12.18 | 7.92 | 23.66 |
| 2026 | 9.14 | 7.21 | 11.07 | 18.35 | 13.07 | 32.75 | 12.70 | 8.33 | 24.63 |
| 2027 | 9.23 | 7.31 | 11.10 | 18.84 | 13.37 | 32.72 | 13.11 | 8.58 | 24.60 |
| 2028 | 9.34 | 7.40 | 11.27 | 19.43 | 13.67 | 34.00 | 13.59 | 8.82 | 25.65 |
| 2029 | 9.40 | 7.36 | 11.37 | 20.33 | 14.22 | 35.49 | 14.33 | 9.28 | 26.89 |
| 2030 | 9.59 | 7.50 | 11.66 | 21.21 | 14.65 | 37.87 | 15.06 | 9.63 | 28.86 |
| 2031 | 9.65 | 7.25 | 11.80 | 21.76 | 14.98 | 38.74 | 15.52 | 9.91 | 29.57 |
| 2032 | 9.90 | 7.45 | 12.13 | 22.17 | 15.20 | 40.07 | 15.86 | 10.09 | 30.67 |
| 2033 | 10.07 | 7.60 | 12.32 | 22.59 | 15.54 | 40.55 | 16.20 | 10.37 | 31.07 |
| 2034 | 10.31 | 7.64 | 12.95 | 23.02 | 15.74 | 42.21 | 16.55 | 10.53 | 32.44 |
| 2035 | 10.55 | 7.88 | 13.25 | 23.45 | 15.71 | 42.99 | 16.91 | 10.50 | 33.08 |
| 2036 | 10.73 | 7.82 | 13.53 | 23.89 | 16.48 | 43.27 | 17.27 | 11.14 | 33.32 |
| 2037 | 10.96 | 8.14 | 13.85 | 24.35 | 16.79 | 44.11 | 17.66 | 11.39 | 34.01 |
| 2038 | 11.06 | 8.17 | 13.76 | 24.83 | 17.06 | 45.60 | 18.05 | 11.62 | 35.25 |
| 2039 | 11.15 | 8.00 | 13.76 | 25.31 | 17.24 | 46.00 | 18.44 | 11.76 | 35.57 |
| 2040 | 11.30 | 8.09 | 13.96 | 25.80 | 17.66 | 47.57 | 18.85 | 12.11 | 36.87 |



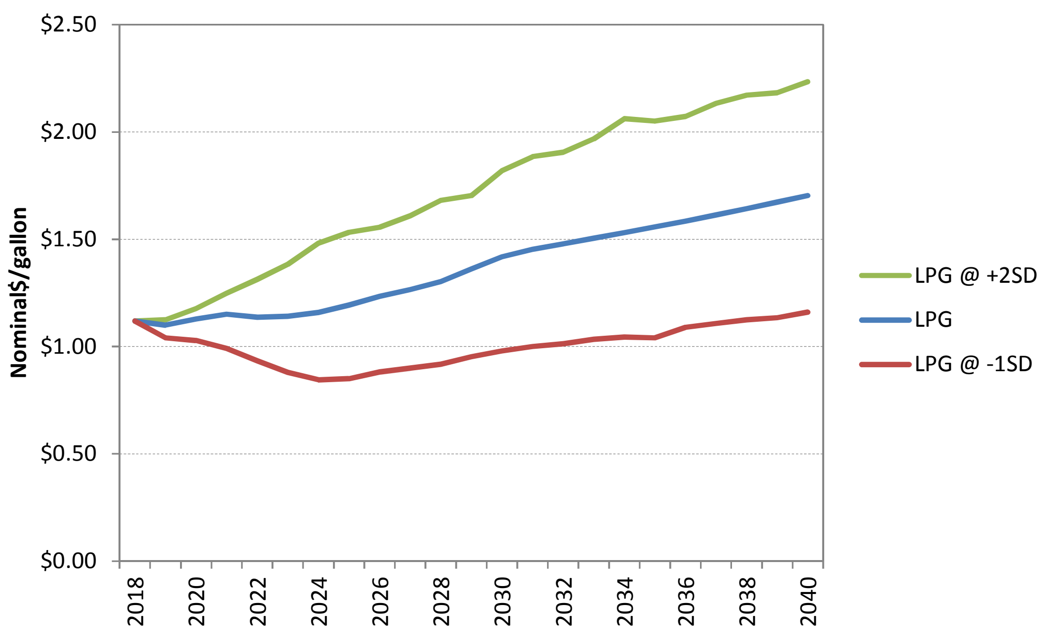
## Exhibit 7-13. Delivered Natural Gas to Costa Sur, LPG to Bayamón, and Coal to AES

| Plant | | Costa Sur | Costa Sur | Costa Sur | Baya-món | Baya-món | Baya-món | AES | AES | AES |
|---|---|---|---|---|---|---|---|---|---|---|
| Fuel | | Natural Gas | Gas @ -1SD | Gas @ +1SD | LPG | LPG @ -1SD | LPG @ +2SD | Coal | Coal @ -1SD | Coal @ +1SD |
| Year \ Unit | | Nom$/ MMBtu | Nom$/ MMbtu | Nom$/ MMbtu | nom$/ gallon | nom$/ gallon | nom$/ gallon | nom$/ ton | nom$/ ton | nom$/ ton |
| 2018 | | 9.02 | 8.88 | 9.12 | 1.12 | 1.12 | 1.12 | 79.43 | 79.43 | 79.43 |
| 2019 | | 8.89 | 8.51 | 9.05 | 1.10 | 1.04 | 1.12 | 72.24 | 68.55 | 76.23 |
| 2020 | | 8.98 | 8.32 | 9.45 | 1.13 | 1.03 | 1.18 | 68.76 | 59.63 | 79.62 |
| 2021 | | 9.42 | 8.39 | 9.91 | 1.15 | 0.99 | 1.25 | 69.02 | 57.21 | 83.77 |
| 2022 | | 9.51 | 8.08 | 10.40 | 1.14 | 0.93 | 1.31 | 68.02 | 56.42 | 82.53 |
| 2023 | | 9.71 | 7.79 | 11.31 | 1.14 | 0.88 | 1.38 | 68.41 | 56.73 | 83.02 |
| 2024 | | 9.97 | 7.73 | 13.09 | 1.16 | 0.85 | 1.48 | 67.69 | 56.15 | 82.11 |
| 2025 | | 10.31 | 7.89 | 13.83 | 1.19 | 0.85 | 1.53 | 68.51 | 56.81 | 83.14 |
| 2026 | | 10.69 | 8.10 | 14.28 | 1.23 | 0.88 | 1.56 | 69.61 | 57.69 | 84.51 |
| 2027 | | 10.97 | 8.34 | 14.39 | 1.27 | 0.90 | 1.61 | 70.73 | 58.59 | 85.92 |
| 2028 | | 11.26 | 8.53 | 14.90 | 1.30 | 0.92 | 1.68 | 71.88 | 59.51 | 87.35 |
| 2029 | | 11.61 | 8.74 | 15.42 | 1.36 | 0.95 | 1.70 | 73.05 | 60.44 | 88.81 |
| 2030 | | 12.07 | 9.05 | 16.30 | 1.42 | 0.98 | 1.82 | 74.24 | 61.39 | 90.30 |
| 2031 | | 12.38 | 9.12 | 16.52 | 1.45 | 1.00 | 1.89 | 75.46 | 62.37 | 91.82 |
| 2032 | | 12.70 | 9.32 | 17.11 | 1.48 | 1.01 | 1.91 | 76.69 | 63.35 | 93.37 |
| 2033 | | 12.99 | 9.59 | 17.41 | 1.50 | 1.03 | 1.97 | 77.95 | 64.36 | 94.94 |
| 2034 | | 13.31 | 9.78 | 18.02 | 1.53 | 1.04 | 2.06 | 79.24 | 65.39 | 96.55 |
| 2035 | | 13.65 | 9.92 | 18.46 | 1.56 | 1.04 | 2.05 | 80.55 | 66.44 | 98.18 |
| 2036 | | 13.95 | 10.21 | 18.60 | 1.59 | 1.09 | 2.07 | 81.89 | 67.51 | 99.86 |
| 2037 | | 14.29 | 10.55 | 19.10 | 1.61 | 1.11 | 2.13 | 83.28 | 68.63 | 101.61 |
| 2038 | | 14.58 | 10.75 | 19.67 | 1.64 | 1.12 | 2.17 | 84.71 | 69.77 | 103.39 |
| 2039 | | 14.86 | 10.85 | 19.80 | 1.67 | 1.13 | 2.18 | 86.17 | 70.94 | 105.21 |
| 2040 | | 15.19 | 11.06 | 20.42 | 1.70 | 1.16 | 2.23 | 87.66 | 72.12 | 107.07 |

Costa Sur Delivered LNG Price




Bayamón Delivered LNG Price



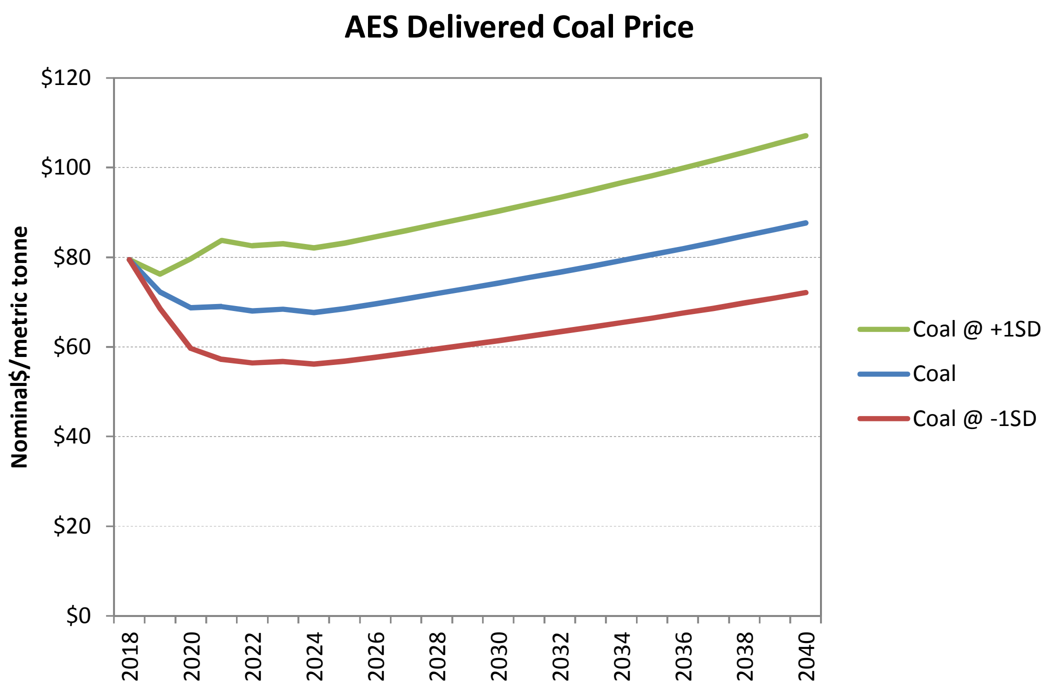
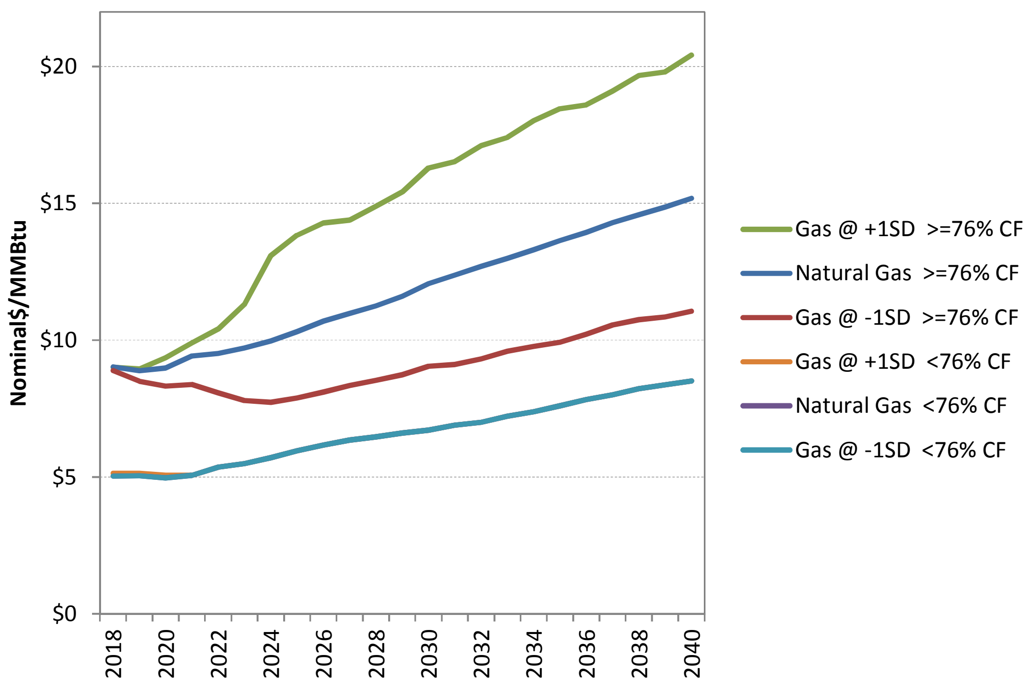



**Exhibit 7-14. Delivered EcoEléctrica Natural Gas Price Forecast (Nominal$/MMBtu)**

| Plant | EcoEléctrica | EcoEléctrica | EcoEléctrica | EcoEléctrica | EcoEléctrica | EcoEléctrica |
|---|---|---|---|---|---|---|
| Fuel | Natural Gas | Gas @ -1SD | Gas @ +1SD | Natural Gas | Gas @ -1SD | Gas @ +1SD |
| Capacity Factor | >=76% CF | >=76% CF | >=76% CF | <76% CF | <76% CF | <76% CF |
| Year / Unit | nom$/ MMBtu | nom$/ MMBtu | nom$/ MMBtu | nom$/ MMBtu | nom$/ MMBtu | nom$/ MMBtu |
| 2018 | 9.02 | 8.88 | 9.02 | 5.04 | 5.04 | 5.14 |
| 2019 | 8.89 | 8.51 | 8.95 | 5.04 | 5.04 | 5.14 |
| 2020 | 8.98 | 8.32 | 9.36 | 4.96 | 4.96 | 5.06 |
| 2021 | 9.42 | 8.39 | 9.91 | 5.06 | 5.06 | 5.06 |
| 2022 | 9.51 | 8.08 | 10.40 | 5.37 | 5.37 | 5.37 |
| 2023 | 9.71 | 7.79 | 11.31 | 5.50 | 5.50 | 5.50 |
| 2024 | 9.97 | 7.73 | 13.09 | 5.71 | 5.71 | 5.71 |
| 2025 | 10.31 | 7.89 | 13.83 | 5.95 | 5.95 | 5.95 |
| 2026 | 10.69 | 8.10 | 14.28 | 6.16 | 6.16 | 6.16 |
| 2027 | 10.97 | 8.34 | 14.39 | 6.35 | 6.35 | 6.35 |
| 2028 | 11.26 | 8.53 | 14.90 | 6.47 | 6.47 | 6.47 |
| 2029 | 11.61 | 8.74 | 15.42 | 6.60 | 6.60 | 6.60 |
| 2030 | 12.07 | 9.05 | 16.30 | 6.71 | 6.71 | 6.71 |
| 2031 | 12.38 | 9.12 | 16.52 | 6.89 | 6.89 | 6.89 |

| Plant | EcoEléctrica | EcoEléctrica | EcoEléctrica | EcoEléctrica | EcoEléctrica | EcoEléctrica |
|---|---|---|---|---|---|---|
| Fuel | Natural Gas | Gas @ -1SD | Gas @ +1SD | Natural Gas | Gas @ -1SD | Gas @ +1SD |
| Capacity Factor | >=76% CF | >=76% CF | >=76% CF | <76% CF | <76% CF | <76% CF |
| Year / Unit | nom$/ MMBtu | nom$/ MMBtu | nom$/ MMBtu | nom$/ MMBtu | nom$/ MMBtu | nom$/ MMBtu |
| 2032 | 12.70 | 9.32 | 17.11 | 7.00 | 7.00 | 7.00 |
| 2033 | 12.99 | 9.59 | 17.41 | 7.22 | 7.22 | 7.22 |
| 2034 | 13.31 | 9.78 | 18.02 | 7.39 | 7.39 | 7.39 |
| 2035 | 13.65 | 9.92 | 18.46 | 7.61 | 7.61 | 7.61 |
| 2036 | 13.95 | 10.21 | 18.60 | 7.82 | 7.82 | 7.82 |
| 2037 | 14.29 | 10.55 | 19.10 | 8.01 | 8.01 | 8.01 |
| 2038 | 14.58 | 10.75 | 19.67 | 8.23 | 8.23 | 8.23 |
| 2039 | 14.86 | 10.85 | 19.80 | 8.38 | 8.38 | 8.38 |
| 2040 | 15.19 | 11.06 | 20.42 | 8.51 | 8.51 | 8.51 |




## 7.3 Value of Lost Load Estimation

As part of PREPA's Integrated Resource Planning (IRP), Siemens performed a loss of load analysis to assess the likelihood that due to generation and/or transmission outages, the system will be unable to meet load for any period of time. The objective of the analysis is to identify hours in which local or system wide supply may be inadequate to meet demand.

The analysis is performed using a Monte-Carlo simulation to capture loss of load hours (LOLH) and Energy Not Served (ENS) considering the expected performance of the generating fleet and the impact of normal transmission limitations. Additionally, for the impact of weather events two approaches are being considered:

Model a scenario representative of system condition after a major storm that is expected to occur with relative frequency (e.g. Category 1 Hurricane) and evaluate the LOLH and ENS for a period of 1 month assuming that the system will stay in this condition.

Model a scenario of the system condition after a major storm that is expected to occur more infrequently (e.g. a Cat 4 Hurricane) in which the system is split into the pre-designed regions (called minigrids). Each minigrid is assumed to operate in isolation for 1 month. An estimation of load not served during minigrid formation can be included.

As part of this IRP, Siemens has estimated the value of lost load (VOLL) based on methodologies applied in other countries or regions. To meet the IRP objectives, Siemens computed a VOLL adjustment for each of the portfolios to evaluate the expected total cost including the cost of maintaining resiliency, which FERC defined as: "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."[50] The VOLL in turn impacts the selection of the recommended portfolio(s) for PREPA. Specifically, one of the IRP objectives is least cost. Traditional IRPs measure the Net Present Value (NPV) of revenue requirements over the IRP planning horizon. Adding VOLL to the NPV of revenue requirements captures the value of a resilient system in the least cost measure.

VOLL is the standard metric used to estimate the economic impact of disruptions in power service to customers, and thus can provide a measure of the magnitude of benefits associated with decreasing the likelihood of power system interruptions. In principle, VOLL is the value that represents a customer's willingness to pay for reliable electricity service or to avoid an outage. 51

VOLL is determined by relating the monetary damage arising from a power interruption (due to the loss of economic activities) to the level of the MWh that is not supplied during an interruption. VOLL is generally measured in US$/MWh. The value of energy not served (ENS) is determined as the VOLL x ENS. VOLL is typically valued separately for different user groups, e.g. residential, commercial and industrial users. The reason for this is that different users are affected differently by the same power interruption.[52]

[50] FERC Docket No. AD18-7-000

[51] London Economics International LLC. (2013, June). Estimating the Value of Lost Load. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf

[52] Institute of Energy and Climate Research – Systems Analysis and Technology Evaluation (IEK-STE), (2015, December). Value of Lost Load: An Efficient Economic Indicator for Power Supply Security? A Literature Review. Retrieved from https://www.frontiersin.org/articles/10.3389/fenrg.2015.00055/full.

### 7.3.1 Methodological Approaches to Estimating VOLL

There are four key methodologies used for estimating VOLL in the field of economics. Exhibit 7-15 shows a brief explanation of each methodology, followed by its theoretical and practical strengths and weaknesses.

**Exhibit 7-15. Key Methodologies Used for Estimating VOLL**

| Method | Description | Strength | Weakness |
|---|---|---|---|
| Revealed Preference Survey (Market Behavior) | ▪ Use of surveys to determine expenditures customers incur to ensure reliable generation (i.e., back-up generators and interruptible contracts) to estimate VOLL | ▪ Uses actual customer data that is generally reliable. | ▪ Only relevant if customers invest in back-up generation<br>▪ Limited consideration of duration and/or timing of outages<br>▪ Difficult for residential customers to quantify expenses |
| Stated Choice Survey (WTA/WTP) | ▪ Use of surveys /interviews to infer a customer's willingness-to-pay (WTP), willingness-to-accept (WTA) and trade-off preferences | ▪ More directly incorporates customer preferences<br>▪ Includes some indirect costs and considers duration and/or timing of outages | ▪ Time-consuming<br>▪ Need to manage for potential biases<br>▪ Large discrepancy between WTP and WTA<br>▪ Residential customers may give unreliable answers due to lack of experience |
| Macroeconomic Analysis | ▪ Uses macroeconomic data and other observable expenditures to estimate VOLL.<br>▪ This approach estimates VOLL by estimating the value of loss of production for non-residential customers and/or the value loss of leisure time for residential customers. | ▪ Few variables<br>▪ Easy to obtain data<br>▪ GDP reasonable proxy for business VOLL | ▪ Does not consider linkages between sectors, productive activities<br>▪ Proxies for cost of residential outages may be arbitrary or bias |
| Case Study Analysis (Blackout Studies) | ▪ Examines actual outages to determine VOLL. In this approach, the resulting damage costs of a real power interruption are recorded retrospectively. | ▪ Uses actual, generally reliable data | ▪ Costly to gather data<br>▪ Available case studies may not be representative of other outages/jurisdictions |

**Note:**
WTP: how much they would pay to either avoid a blackout or to be guaranteed a higher level of supply security.
WTA: how much money consumers would have to be offered for them to accept a reduction in supply security or to retain the present level of security instead of being upgraded to a higher level.
Sources:

1. London Economics International LLC. (2013, June). Estimating the Value of Lost Load. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf,
2. Institute of Energy and Climate Research – Systems Analysis and Technology Evaluation (IEK-STE), (2015, December).
3. Value of Lost Load: An Efficient Economic Indicator for Power Supply Security? A Literature Review. Retrieved from https://www.frontiersin.org/articles/10.3389/fenrg.2015.00055/full.

### 7.3.2 VOLL Trends

VOLL estimates are extremely sensitive to a number of factors, including assumptions used in survey analysis, time and duration of outage, time of advanced notification of outage, customer profile, industry sector and many other factors. Average VOLLs for a developed, industrial economy range from approximately $9,000/MWh to $45,000/MWh. Looking on a more disaggregated level, residential customers generally have a lower VOLL ($0/MWh - $17,976/MWh) than commercial and industrial (C&I) customers (whose VOLLs range from about $3,000/MWh to $53,907/MWh).[53] Other trends include:

In general, residential customers are expected to have the lowest VOLLs, while small C/I customers have the highest VOLLs. Small C/I customers are more labor and capital intensive than residential customers and are less likely to prepare for operational risks such as outages by using interruptible contracts and back-up generation as hedges against outages than medium and large C/I customers, leading to generally higher VOLLs.

Residential VOLLs in the U.S. are in the $1,000/MWh – $4,000/MWh range, while VOLLs in international jurisdictions tend to be much higher. This variation may be due to a variety of factors, including different consumption patterns and costs of electricity in the regions studied, as well as the different methodologies used to estimate VOLL in each study.

Long duration outages lead to higher VOLL as the indirect and induced costs of the outage increase over time (loss of wages, loss of perishable goods, etc.).

Exhibit 7-16 shows the results of recent VOLL studies, broken down according to methodology applied and end-user group. Due to the different degrees of differentiation, the VOLL results of the studies are shown as ranges.[54]

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[53] London Economics International LLC. (2013, June). Estimating the Value of Lost Load. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf

[54] London Economics International LLC. (2013, June). Estimating the Value of Lost Load. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf

**Exhibit 7-16. Results of Recent VOLL Studies**

| Region/Market | Methodology | System-wide VOLL | Residential | Non-Residential | |
|---|---|---|---|---|---|
| | | | | *Large C/I* | *Small C/I* |
| **US - Southwest** | Analysis of past survey results | | $0 | $8,774 | $35,417 |
| **US - MISO** | Analysis of past survey results/ Macroeconomic analysis | | $1,735 | $29,299 | $42,256 |
| | | | | *Commercial* | *Industrial* |
| **Austria** | Survey | | $1,544 | | |
| **New Zealand** | Survey | $41,269 | $11,341 | $77,687 | $30,874 |
| **Australia - Victoria** | Survey | $44,438 | $4,142 | $28,622 | $10,457 |
| **Australia** | Analysis of past survey results | $45,708 | | | |
| **Republic of Ireland (2010)** | Macroeconomic analysis | $9,538 | $17,976 | $10,272 | $3,302 |
| **Republic of Ireland (2007)** | Macroeconomic analysis | $16,265 | | | |
| **US - Northeast** | Macroeconomic analysis | $9,283-$13,925 | | | |

Note: All values in 2012 US$/MWh

Sources: London Economics International LLC. (2013, June). Estimating the Value of Lost Load. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf

## 7.4 First Approach to Calculate Puerto Rico's VOLL

One approach to calculate Puerto Rico's VOLL is to understand which of the nine jurisdictional studies shown in Exhibit 7-16 has the most similarities to Puerto Rico. The applicability of the VOLL estimates from the nine jurisdictional studies to Puerto Rico is determined by considering the similarities between the studied geographic region/market and Puerto Rico. The metrics include: (1) economic and demographic (population and GDP, urban/rural, temperature); (2) electricity consumption patterns; and (3) market design. The mix of customer class also plays a role. In FY2016, residential, small C&I[55], and medium/large C&I[56] customers represented approximately 38%, 13% and 50% respectively of PREPA's total sales. As shown in Exhibit 7-17, the most applicable study to PREPA is New Zealand, which has a system-wide VOLL of $41,269/MWh (Residential: $11,341/MWh, Commercial: $77,687/MWh, Industrial: $30,874/MWh) in 2012 dollar.

[55] Small C&I= customers with an annual consumption under 50,000 kWh

[56] Medium/Large C&I = customers with an annual consumption over 50,000 kWh

## Exhibit 7-17. Proxy Estimates with Potential Applicability to PREPA

| Economic and Demographic Factors | Puerto Rico | New Zealand[5] | Ireland[5] | Victoria, Australia[5] | Australia[5] |
|---|---|---|---|---|---|
| Population Density (people/mile²)[1] | 385 | 42 | 168 | 64 | 7.3 |
| Average Temperatures (°F)[3] | Winter: 64<br>Summer: 71 | Winter:50-59<br>Summer:68-86 | Winter:42<br>Summer:58 | Winter:44-59<br>Summer:57-79 | Winter:33-91<br>Summer:51-97 |
| GDP per Capita (2011 USD$)[2] | 35,093 | 38,563 | 48,423 | 59,378 | 60,979 |
| Rural (%)[3] | 1% rural | 14% rural | 38% rural | 6.5% rural | 11% rural |
| Electricity Consumption Patterns | | | | | |
| Total Annual Consumption (MWh)[4] | 16,995,838 | 40,700,000 | 26,100,000 | 56,250,000 | 225,000,000 |
| Peak Demand (MW)[4] | 3,685 | 6,330 | 5,090 | 9,378 | 13,781 |
| Market Design | | | | | |
| Wholesale Market[6] | No | Yes | Yes | Yes | Yes |
| Retail Market[6] | No | Yes | Yes, but limited | Yes | Yes |
| Connection with other systems[6] | No | No | Yes, limited | Yes | No |
| Overall Applicability[6] | | High | High | Moderate | Moderate |

Sources:

1. Trading Economics. Retrieved from https://tradingeconomics.com/puerto-rico/population-density-people-per-sq-km-wb-data.html
2. World Bank (2015, April). https://data.worldbank.org/indicator/NY.GDP.PCAP.PP.CD?order=wbapi_data_value_2013+wbapi_data_value+wbapi_data_value-last&sort=desc
3. NREL. (2015, March). Energy Transition Initiative. Retrieved from https://www.nrel.gov/docs/fy15osti/62708.pdf
4. PREPA (FY2016-2017)
5. London Economics International LLC. (2013, June). Estimating the Value of Lost Load. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf

Adapting New Zealand's VOLL estimates of each sector and using the expected unserved power (kWh) per sector specific for Puerto Rico (using Puerto Rico's reliability index[57] and consumer load consumption), Puerto Rico's system wide VOLL results in $31,897/MWh in 2018 dollar as shown in Exhibit 7-18.

[57] See Exhibit 7-18 and Exhibit 7-19 for more detail on reliability index.

**Exhibit 7-18. 1st Approach VOLL Results Applicable to PREPA**

| Sector | Number of Customers | Unserved Energy | Cost Per Average MWh | Total Cost |
|---|---|---|---|---|
| | | MWh | 2018$MWh | 2018$ |
| Residential | 1,335,643 | 10,345 | 12,269 | 126,926,034 |
| Small C&I | 116,094 | 3,490 | 84,045 | 293,332,602 |
| Medium and Large C&I | 11,707 | 13,650 | 33,401 | 455,926,165 |
| Total | 1,463,444 | 27,471 | 31,895 | 876,184,801 |

Sources: Siemens, PREPA

## 7.5 Second Approach to Calculate Puerto Rico's VOLL

Puerto Rico's power grid is unique as it supports a large commercial and industrial load in a tropical climate and a hurricane zone, with pharmaceuticals, textiles, petrochemicals, and electronics being the major industries.

The Interruption Cost Estimate (ICE) calculator is a publicly available web-based tool developed by Lawrence Berkeley National Laboratory (Berkeley Laboratory) designed to estimate economic costs of power interruptions where you can modify the specific parameters/inputs. It is based on more than 20 years of utility-sponsored surveys on the costs of power interruptions to customers. To ensure its continued effectiveness, the tool continues to be augmented by research on the latest methods for collecting and developing information on the economic consequences of power interruptions on businesses, residences, and society at large. [58]

As the first step, Siemens analyzed the reliability indices including System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI) provided by PREPA and shown in Exhibit 7-19. These indices include the effect of all outages including generation transmission and distribution but not the effect of major event days (MED).

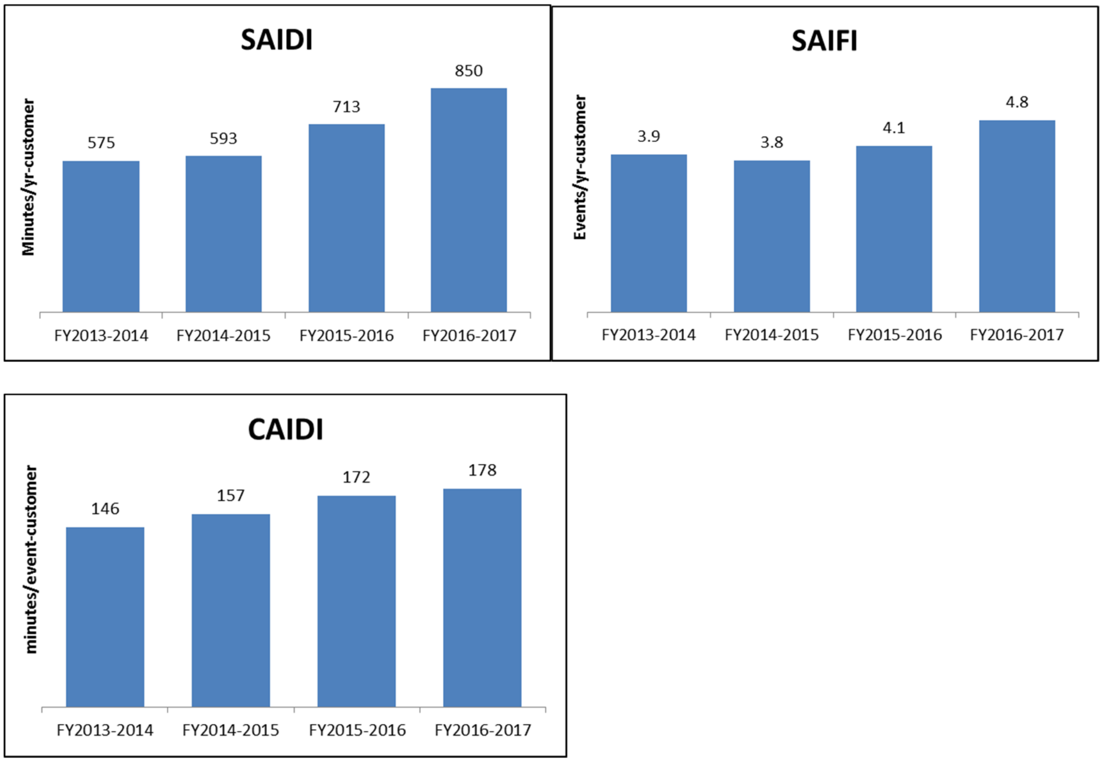
SAIDI index is based on the amount of time the average customers experience a sustained outage in a given year. From FY2013 to FY2016, the average SAIDI for Puerto Rico was about 683 minutes per customer per year.

SAIFI index represents the number of times the average customer experiences a sustained outage in a given year. From FY2013 to FY2016, the average SAIFI for Puerto Rico was about 4.2 events per customer per year.

[58] Berkeley Lab's Electricity Markets & Policy Group (EMP Group). (2018). Interruption Cost Estimation (ICE) Calculator. Retrieved from https://icecalculator.com/interruption-cost

CAIDI index represents the average restoration time when customers are impacted by a sustained outage. It is determined by dividing SAIDI by SAIFI. From FY2013 to FY2016, the average CAIDI for Puerto Rico was 163 minutes per event per customer.

**Exhibit 7-19. Puerto Rico's Reliability Indexes (SADI, SAIFI, and CAIDI)**




Source: PREPA (IEEE Benchmark Report)

As the second step, Siemens introduced other inputs specific for Puerto Rico as presented in Exhibit 7-20.

**Exhibit 7-20. PREPA's Parameters to Calculate the Interruption Costs**

| Parameter | Description | Units | Value |
|---|---|---|---|
| Reliability Index[1] | SAIDI | minute/year-customer | 850 |
| | SAIFI | events/year-customer | 4.8 |
| | CAIDI | minutes/event-customer | 178 |
| Annual Usage per Customer[2] | Residential | MWh/customer | 5 |
| | Small C&I | MWh/customer | 19 |
| | Medium and Large C&I | MWh/customer | 721 |

| Parameter | Description | Units | Value |
|---|---|---|---|
| Number of Customers per Class[2] | Residential | Number | 1,335,643 |
| | Small C&I | Number | 116,094 |
| | Medium and Large C&I | Number | 11,707 |
| Industry Composition[3] | Construction | % | 5% |
| | Manufacturing | % | 9% |
| | Other Industries | % | 86% |
| Household Income[3] | Average | USD | 27,017 |
| Power Interruption Distribution[4] | Outages from 5am to 5pm | % | 46% |
| | Outages during Summer (June-Sept) | % | 50% |
| Back-up Generation Percentage per Class[4] | Small C&I with Back-up or Power Conditioning | % | 30% |
| | Medium/ Large C&I with Back-up or Power Conditioning | % | 46% |
| U.S. State[5] | U.S. State | U.S. State | Hawaii |

Sources:

1. PREPA- IEEE Benchmark Report (FY2016-2017)
2. PREPA (FY2016-2017)
3. U.S. Bureau of Labor Statistics. Retrieved from https://www.bls.gov/eag/eag.pr.htm,
4. Berkeley Lab's Electricity Markets & Policy Group (EMP Group). (2018). Interruption Cost Estimation (ICE) Calculator. Retrieved from https://icecalculator.com/interruption-cost
5. The ICE Calculator uses a default set of inputs based on the selected state. Puerto Rico is not an option for the ICE Calculator; therefore, Siemens used Hawaii, as it is an island and has a similar GDP as Puerto Rico.

As a result, Siemens estimated Puerto Rico's system-wide VOLL at $57,940/MWh (Residential: $4,037/MWh, Small C&I: $219,237/MWh, Large C&I: $57,488/MWh) in 2018 dollars. The Berkeley Lab's ICE calculator generated results as shown in Exhibit 7-21.

**Exhibit 7-21. Second Approach VOLL Results Applicable to PREPA**

| Sector | Number of Customers | Unserved Energy | Cost Per Average MWh | Total Cost |
|---|---|---|---|---|
| | | kWh | 2018$ | 2018$ |
| Residential | 1,335,643 | 10,345,165 | 4,037 | 41,763,433 |
| Small C&I | 116,094 | 3,490,198 | 219,237 | 765,180,534 |
| Medium and Large C&I | 11,707 | 13,650,221 | 57,488 | 784,723,925 |
| Total | 1,463,444 | 27,471,029 | 57,940 | 1,591,667,892 |

Source: Siemens, Berkeley Lab's Electricity Markets & Policy Group (EMP Group). (2018). Interruption Cost Estimation (ICE)Calculator. Retrieved from https://icecalculator.com/interruption-cost

### 7.5.1 Conclusion

In summary, the two approaches yielded a wide range of estimated VOLL for Puerto Rico. The second approach estimates Puerto Rico's system-wide VOLL at $57,940 which is $26,043 higher than the first approach. Exhibit 7-22 summarizes the results for the two approaches. The 2nd approach results in small C&I and Medium/Large C&I VOLL numbers that are out of range compared to the literature VOLL trends discussed above as well as in other documentation reviewed. Additionally, Siemens estimated the VOLL for Puerto Rico using other weakly related markets like the Mid Continent ISO (MISO) in the U.S. and obtained values similar to those of method 1 (27,450 in 2018$/MWh). Therefore, for the 2018 IRP, Siemens chose to utilize the results from the first approach as proxy to calculate the value of lost load for PREPA customers.

**Exhibit 7-22. PREPA VOLL Estimates**

| Sector | 1st Approach (2018$/MWh) | 2nd Approach (2018$/MWh) |
|---|---|---|
| Residential | 12,270 | 4,037 |
| Small C&I | 84,051 | 219,237 |
| Medium and Large C&I | 33,403 | 57,488 |
| System | 31,897 | 57,940 |

Part
8

# Resource Plan Development

This section presents considering the scenarios and sensitivities described in Section 5, the result of the assessment of the various resulting generation portfolios and its metrics and conclusions and recommendations derived thereof.

## 8.1 Overview of Scenario Results

Siemens investigated over 78 LTCE plans as potential resource plans for PREPA. These plans included numerous plausible options including those suggested by stakeholders. These different plans considered points that were critical for the final IRP including, among other issues:

- Uncertainty associated with the future customer demand
- Future prices of generations technologies, e.g., wind, solar, battery storage
- Future prices of fuels, particularly natural gas and the potential availability of infrastructure to deliver additional gas to the island
- Prudent methods to increase resilience and reliability
- Practical limits to PREPA's ability to interconnect new battery energy storage and renewables generation
- Timing of new generation resource additions and the timing of retirements of existing aged fossil fueled resources.

This initial screening of the over 78 LTCE plans resulted in the identification of a final set of 32 LTCE plans that were assessed to identify the recommended resource plan and the common no regret / minimum regret elements of across plans with merit.

Note that Scenario 2 is not included in the final 32 LTCE considered as it was dropped based in the initial screen and in accordance to PREB.

Exhibit 8-1 below provide the NPV results of the 32 LTCE plans with their Scenario, Strategy, For the determination of the NPV, we need a discount rate applicable to PREPA as a public utility; for this we selected we 9% (6.86% on a real dollar basis) as this was the same discount rate used in the first IRP and it is based on the assumption that PREPA (or its successors) is able to resolve its current financial issues and can borrow the capital at this rate.

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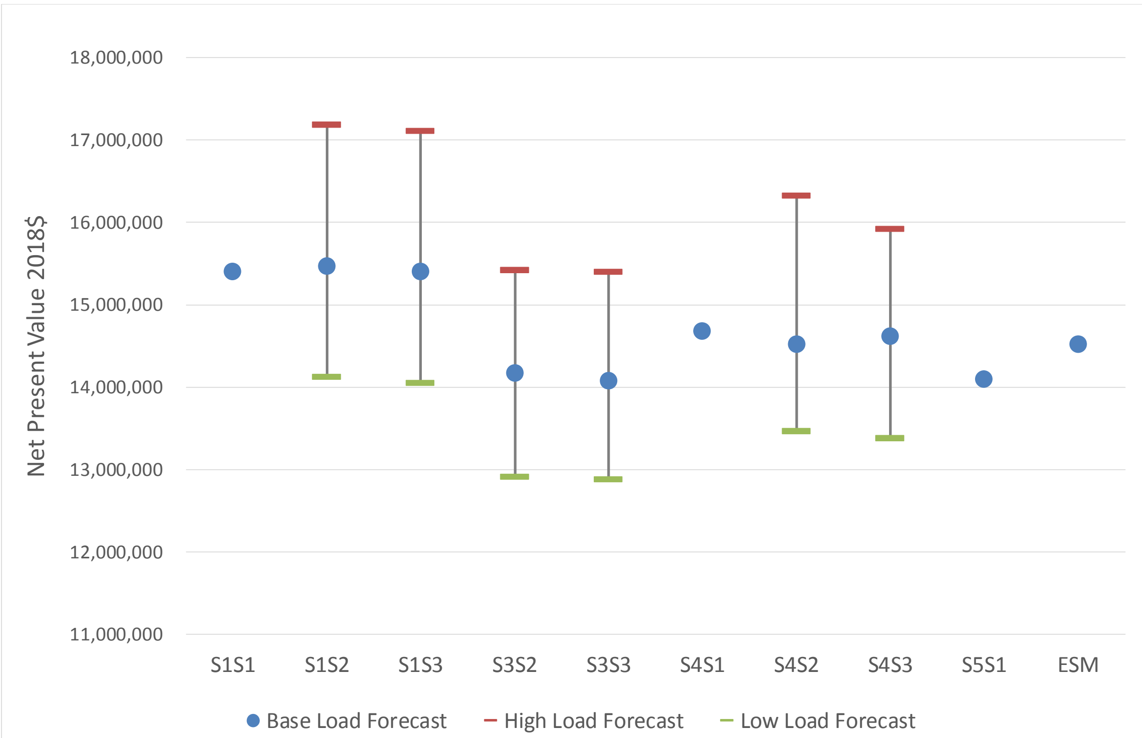
## Exhibit 8-1: Summary of LTCE Plans

| Count | Case ID | Scenario | Strategy | Sensitivity | Load | NPV @ 9% 2019-2038 $000 | F - Class Palo Seco 2025 | F - Class Costa Sur 2025 | F-Class Mayaguez 2028 | F-Class Yabucoa 2025 | Small CCGT (LPG/NG) North | F - Class San Juan 2029 | Medium CCGT Yabucoa 2024 | New Solar 2019 - 2022 | BESS 2019 - 2022 | New Solar Total | BESS Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | S1S2B | 1 | 2 | | Base | **15,458,037** | X | ✔ (2025, 2028) | X | X | X | X | X | 1200 | 1200 | 3720 | 2140 |
| 2 | S1S2H | 1 | 2 | | High | **17,177,891** | X | ✔ (2025 x 2, 2033) | X | X | X | X | ✔ Bayamon 2027 | 1200 | 1240 | 4320 | 1880 |
| 3 | S1S2L | 1 | 2 | | Low | **14,120,288** | X | ✔ (2025, 2028) | X | X | X | X | X | 1200 | 1160 | 3300 | 1800 |
| 4 | S1S3B | 1 | 3 | | Base | **15,401,758** | ✔ | ✔ (2025, 2028) | X | X | X | X | X | 1200 | 1120 | 3720 | 1640 |
| 5 | S1S3H | 1 | 3 | | High | **17,109,321** | ✔ (141 MW) | ✔ (2025, 2028) | X | X | X | X | X | 1200 | 940 | 4260 | 2500 |
| 6 | S1S3L | 1 | 3 | | Low | **14,052,124** | X | ✔ (2025, 2028) | X | X | X | X | X | 1200 | 1120 | 3240 | 1900 |
| 7 | S1S2S1B | 1 | 2 | 1 | Base | **14,852,306** | ✔ (141 MW) | ✔ (2025, 2028) | X | X | X | X | X | 1200 | 1120 | 3840 | 2700 |
| 8 | S1S2S2B | 1 | 2 | 2 | Base | **16,640,966** | X | ✔ (2025 x 2, 2028) | X | X | X | X | X | 1200 | 1140 | 4020 | 1800 |
| 9 | S1S2S3B | 1 | 2 | 3 | Base | **17,147,407** | ✔ (141 MW) | ✔ (2025 x 2, 2036) | X | X | X | X | X | 1200 | 1240 | 4320 | 1880 |
| 10 | S1S1B | 1 | 1 | | Base | **15,395,763** | X | ✔ (2025, 2028) | X | X | X | X | X | 1200 | 1160 | 3720 | 2220 |
| 11 | S3S2B | 3 | 2 | | Base | **14,167,571** | ✔ | ✔ | X | X | X | X | ✔ | 1500 | 980 | 4020 | 2380 |
| 12 | S3S2H | 3 | 2 | | High | **15,414,838** | ✔ | ✔ | X | X | X | X | X | 1500 | 1180 | 4560 | 3260 |
| 13 | S3S2L | 3 | 2 | | Low | **12,910,613** | ✔ 2027 | ✔ | X | X | X | X | X | 1500 | 940 | 3480 | 1980 |
| 14 | S3S3B | 3 | 3 | | Base | **14,074,355** | ✔ | ✔ | X | X | X | X | X | 1500 | 1020 | 2760 | 3960 |
| 15 | S3S3H | 3 | 3 | | High | **15,394,694** | ✔ 2027 | ✔ | X | X | ✔ (76MW) | X | ✔ | 1500 | 1100 | 4560 | 2220 |
| 16 | S3S3L | 3 | 3 | | Low | **12,876,825** | ✔ 2027 | ✔ | X | X | X | X | X | 1500 | 960 | 3420 | 2440 |
| 17 | S4S2B | 4 | 2 | | Base | **14,520,725** | ✔ | ✔ | ✔ | X | X | X | X | 1200 | 900 | 2220 | 1080 |
| 18 | S4S2H | 4 | 2 | | High | **16,320,803** | ✔ | ✔ | ✔ | X | X | ✔ | ✔ | 1200 | 800 | 2580 | 960 |
| 19 | S4S2L | 4 | 2 | | Low | **13,467,116** | ✔ | ✔ | X | X | X | X | X | 1200 | 1100 | 2100 | 1160 |
| 20 | S4S3B | 4 | 3 | | Base | **14,615,781** | ✔ | ✔ | ✔ | X | X | X | X | 1200 | 900 | 2340 | 1540 |
| 21 | S4S3H | 4 | 3 | | High | **15,920,492** | ✔ | ✔ | ✔ | ✔ | X | X | X | 1200 | 1000 | 2580 | 1420 |
| 22 | S4S3L | 4 | 3 | | Low | **13,385,318** | ✔ | ✔ | X | ✔ (2028) | X | X | X | 1200 | 1080 | 1920 | 1080 |
| 23 | S4S2S3B | 4 | 2 | 3 | Base | **14,245,331** | ✔ | ✔ | X | X | X | X | X | 1200 | 920 | 2160 | 1020 |
| 24 | S4S2S4B | 4 | 2 | 4 | Base | **14,613,817** | ✔ | ✔ 2027 | X | ✔ | X | X | X | 1200 | 1160 | 2340 | 1220 |
| 25 | S4S2S5B | 4 | 2 | 5 | Base | **15,592,548** | ✔ | ✔ | X | X | X | X | ✔ | 1200 | 580 | 2340 | 960 |
| 26 | S4S2S6B | 4 | 2 | 6 | Base | **15,518,271** | ✔ | ✔ | ✔ (2025) | X | X | ✔ (2028) | ✔ | 720 | 620 | 780 | 620 |
| 27 | S4S1B | 4 | 1 | | Base | **14,677,616** | ✔ | ✔ | ✔ | X | X | X | X | 1200 | 900 | 2340 | 1460 |
| 28 | S5S1B | 5 | 1 | | Base | **14,094,716** | ✔ | 302 + 369 | X | X | X | X | X | 1200 | 1020 | 2160 | 1020 |
| 29 | S5S1S5B | 5 | 1 | 5 | Base | **14,743,201** | ✔ | ✔ | X | X | X | X | X | 1200 | 1060 | 2340 | 1400 |
| 30 | ESM Plan | 4 | 2 | | Base | **14,511,798** | ✔ | Eco Instead | X | ✔ | ✔ | X | X | 720 | 440 | 900 | 800 |
| 31 | ESM high | 4 | 2 | | High | | ✔ | Eco Instead | X | ✔ | ✔ | X | X | | | | |
| 32 | ESM low | 4 | 2 | | Low | | ✔ | Eco Instead | X | ✔ | ✔ | X | X | | | | |

The discount rate above should not be confused with the WACC which the weighted cost of capital for private parties that are assumed to invest in the resource additions and used for the determination of costs to PREPA as fixed charges.

Exhibit 8-2 below provides a summary of the NPV results of the ten primary scenario and strategy combinations for the Base, High and Low load forecasts.

**Exhibit 8-2: Summary Scenarios**




As can be seen in prior table and chart, Scenario 3 Strategy 2 (S34S2) and Scenario 3 Strategy 3 (S3S3) third lowest ($14.17B) and lowest ($14.07B) NPV for the base load forecasts. These two plans assume a deeper reduction of renewable and storage (NREL Low for PV) and are indicative of the impact of this assumption. However, they may have problems for its practical implementation given that the amounts of PV generation required over the long term almost doubles the peak load and at times of light load it could be several higher, which would strain the rest of resources in the system including the storage and could lead to unexpected curtailment. For this reason, we see this case as an upside to be considered as the IRP is implemented and indicative of the potential gains to be had if both the cost of PV declines faster than the base case and greater amounts of renewable can be safely operated. However, Scenario 3 is not considered the preferred portfolio.

Scenario 5 Strategy 1 (S5S1) provides the second lowest NPV results ($14.09B) for the base load forecast. This LTCE plan is based on a centralized strategy and was determined not to be the least cost option, nor the preferred resource plan, due to the high levels of load shedding that would be required during a major storm that segments the island in the MiniGrids proposed.

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The fourth and fifth lowest NPV were for the ESM plan ($14.51B) and Scenario 4 Strategy 2 (S4S2) ($14,52B). These plans were determined to be practical and low cost plans that contain the recommended path forward. In fact, these plans also were ultimately seen contain a common set of no regret / minimum regret elements in the near term plan that were shared by some of the other LTCE plans with favorable results depending on the future conditions.

The remainder of the LTCE plan (i.e., S1S1, S1S2, S1S3, S4S1, S4S3) had higher NPV costs for the Base load forecast and no other differentiators that would have positioned them as more desirable than ESM and S4S2.

We discuss below each of the scenarios.

## 8.2 Scenario 4 Results

The generation portfolio identified as Scenario 4 Strategy 2 (S4S2) result in a plan that meets the criteria of least cost, resilience and viability in terms of installation of solar and battery storage, as well as flexibility provided by local thermal generation on a MiniGrid level in Puerto Rico. The Strategy 2 used for the formulation of the Portfolio is focused on distributed resources, which translate into a requirement that at least 80% of the peak demand needs to be supplied locally. This strategy provides a distributed system of flexible generation and MiniGrids more resilient and closer to the customer. The portfolio generation mix was also confirmed to be able to supply the levels of forecast critical load.

The Scenario 4 considers the option of development of LNG terminals at Yabucoa (east coast) and Mayagüez (west coast) through ship-based LNG. The scenario also includes gas to the north through land-based LNG at San Juan, which could achieve permitting approval. The scenario assumes solar and storage costs and availability based on reference case assumptions.

The following main assumptions were also included in the simulation of this scenario:

- Load Forecast is treated via a Base, High and Low case.
- AES is assumed to expire in 2027 and EcoEléctrica is assumed to renew in 2022 with a reduction of the fixed payments to 55% (new 2022 payment $108 million down from 240 million the prior year) and the being able to cycle as required for the integration of renewable.
- San Juan Units 5 & 6 are converted to gas in June 2019. San Juan units are subjected to a capacity payment of $5 million on an annual basis per unit until 06/30/2024.
- Afterwards, the capacity payment is zero. San Juan units are subjected to fuel constraints at San Juan (ship-based fuel constraint for July 2019-June 2025, and land-based LNG constraint from July 2024 through the end of the forecast period.
- Energy Efficiency as per the requirement of Regulation No. 9021, i.e., 2% per year of incremental savings attributable to new energy efficiency programs for 10 years.

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- The scenario assumes solar and storage costs and availability based on reference case assumptions. PV limited to 300 MW in 2020 and 2021 and 600 MW onwards. Storage limited to 180 MW in 2019, 300 MW annually in 2020 and 2021, and 600 MW onwards.
- Minimum RPS targets of 12% by 2022, 15% by 2027 and 20% by 2035. The plan achieved much higher levels.

As indicated in Section 5, the Scenario 4 was evaluated considering three load growth levels (low, base and high) and two strategies (2 and 3). Strategy 1 with the base load growth was also considered as well as two sensitivities; no land based LNG terminal in San Juan (sensitivity 4) and high cost of gas (sensitivity 5). Exhibit 8-3 has a summary of the expansion decisions under all cases considered for Scenario 4 that will be discussed in further detail in the next sections. As can be observed there is significant agreement on results, which can be used to identify the preferred robust decisions; i.e. those that would minimize the regret, in case that adverse conditions were to happen in the future (e.g. higher prices than expected, lower load, etc.).

**Exhibit 8-3. Scenario 4 Summary of results**

| | Thermal Generation Results | | | | | | | Renewable Generation Results | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Case ID** | F - Class Palo Seco 2025 | F - Class Costa Sur 2025 | F-Class Mayaguez 2028 | F-Class Yabucoa 2025 | Small CCGT (LPG/NG) North | F - Class San Juan 2029 | Medium CCGT Yabucoa 2024 | Peakers (small CC) 2019-2022 | New Solar 2019 - 2022 | BESS 2019 - 2022 | New Solar 2023 - 2028 | BESS 2023 - 2028 | New Solar Total | BESS Total |
| S4S2B | ✔ | ✔ | ✔ | X | X | X | X | 388 | **1200** | 900 | 1020 | 40 | 2220 | 1080 |
| S4S2H | ✔ | ✔ | ✔ | X | X | ✔ | ✔ | 479 | **1200** | 800 | 1380 | 0 | 2580 | 960 |
| S4S2L | ✔ | ✔ | X | X | X | X | X | 280 | **1200** | 1100 | 900 | 60 | 2100 | 1160 |
| S4S3B | ✔ | ✔ | ✔ | X | X | X | X | 388 | **1200** | 900 | 1140 | 160 | 2340 | 1540 |
| S4S3H | ✔ | ✔ | ✔ | ✔ | X | X | X | 440 | **1200** | 1000 | 1380 | 0 | 2580 | 1420 |
| S4S3L | ✔ | ✔ | X | ✔ (2028) | X | X | X | 280 | **1200** | 1080 | 720 | 0 | 1920 | 1080 |
| S4S2S3B | ✔ | ✔ | X | X | X | X | X | 303 | **1200** | 920 | 960 | 20 | 2160 | 1020 |
| S4S2S4B | ✔ | ✔ 2027 | X | ✔ | X | X | X | 327 | **1200** | 1160 | 1140 | 0 | 2340 | 1220 |
| S4S2S5B | ✔ | ✔ | X | X | X | X | ✔ | 591 | **1200** | 580 | 1140 | 80 | 2340 | 960 |
| S4S2S6B | ✔ | ✔ | ✔ (2025) | X | X | ✔ (2028) | ✔ | 204 | **720** | 620 | 0 | 0 | 780 | 620 |
| S4S1B | ✔ | ✔ | ✔ | X | X | X | X | 324 | **1200** | 900 | 1140 | 0 | 2340 | 1460 |

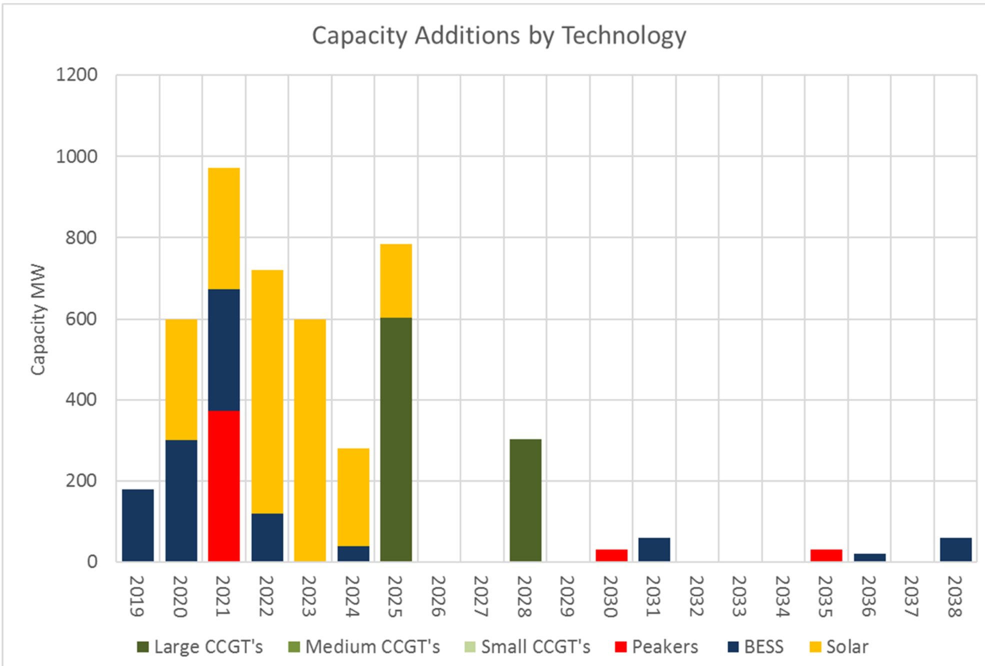
## 8.2.1 Capacity Additions and Retirements

The economic simulation of Scenario 4 under strategy 2 results in 2,220 MW of utility scale PV additions over the study period with 300 MW added as soon as 2020. A total of 1,200 MW is added in 2020-2022, which is consistent across the high and low load cases and it is also seen across the sensitivities that drive higher levels of renewable; high gas prices or lower costs of renewables (see Exhibit 8-3). Furthermore, even in Sensitivity 6 with high capital costs for renewables, the amount of solar built is consistent with 300 MW per year in 2020 and 2021.

The above indicates that the decision to build at least 1,200 MW of solar in the short to medium-term in Puerto Rico, is robust (no regret) provided that the capital cost for solar photovoltaic are as projected (see Part 6 of this report). If capital costs for solar photovoltaic get higher, smaller amounts would be advisable (780 MW by 2022 as shown in Exhibit 8-3 S4S2S6B –Sensitivity 6).

In scenario 4, 1,080 MW of battery energy storage is built over the study period, mostly in 2019-2022, with 900 MW built. In the high and low load cases 800 to 1,100 MW of storage is built in the same period (see Exhibit 8-3). A robust decision is to build at least 800 MW of storage in the short to medium-term in Puerto Rico, with the expected storage capital prices. With high prices this value is reduced to 620 MW by 2022.

**Exhibit 8-4:S2S2 Portfolio Base Load Forecast Capacity Additions**




| Technology / MW | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|
| Large CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 604 | 0 | 0 | 302 |
| Medium CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Peaking Units | 0 | 0 | 372 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| BESS | 180 | 300 | 300 | 120 | 0 | 40 | 0 | 0 | 0 | 0 |
| **Total Distchable Additions** | 180 | 300 | 672 | 120 | 0 | 40 | 604 | 0 | 0 | 302 |
| Solar | 0 | 300 | 300 | 600 | 600 | 240 | 180 | 0 | 0 | 0 |
| **Total Additions** | 180 | 600 | 972 | 720 | 600 | 280 | 784 | 0 | 0 | 302 |

Three large CCGTs are installed (906 MW in total), one F Class in Palo Seco (Bayamon), and one F-Class in Costa Sur (Ponce West), both in 2025 (604 M). One more F class is installed, later in 2028 in Mayaguez (302 MW), after AES retirement, under the base load forecast. In the high load case, the same units are added, in addition to one more F class at in San Juan in 2029 and a medium CCGT in Caguas (Yabucoa). With respect of this last high load case and as will be shown below using Strategy 3 a plan was identified where a F-Class at Caguas (Yabucoa) is built instead of the medium CCGT and the F-Class at San Juan. This option results in lower costs and may indicate a preferred strategy if this high load were to happen.

In the low load case, the F class at Palo Seco and Costa Sur are added but not the F class in Mayaguez in 2028 (see Exhibit 8-3).

The F-Class CCGT at Palo Seco was also observed under all Scenarios that considered that a land-based LNG terminal could be developed; that is Scenario 3 and Scenario 5. It was also present in Scenario 2 that was dropped from further analysis in the initial runs. Moreover, in most Scenarios this development should be carried out as soon a as possible and only under Scenario 3 that considers a deeper reduction in the cost of renewable this investment could be displaced to 2027 as shown in Exhibit 8-3. Thus, we can confirm at this moment that adding a combined cycle (F-Class) at Palo Seco is a no regret decision.

Similarly, all scenarios have a new F-Class at Costa Sur by 2025 and EcoEléctrica is retired. So, the decision to build an F-Class in Costa Sur is robust, with the only caveat that depending on the renegotiation of the contract, it could be possible to maintain EcoEléctrica instead.

As will be presented below (Section 8.2.9) Strategy 3, has the same decisions for the combined cycle generation and very similar on renewable for the base case (see Exhibit 8-3). Under the high load forecast Strategy 3 develops an F-Class CCGT at Caguas (Yabucoa) and this results in lower cost that the corresponding case under Strategy 2 (2% lower). For low load Strategy 3 also develops the F-Class CCCGT at Yabucoa but by 2028 and reduces the amount of PV and storage as compared with Strategy2 (costs are about 1% lower).

Based on the above we observe that the decision of building a large combined cycle at Mayaguez and/or Yabucoa should be part of the least cost path and hence it is recommended to start the preliminary engineering and environmental assessment of both terminals, with view to an RFP process.

436 MW of peaking generation is added (133 MW diesel and 303 MW gas fuel based - containerized) by 2038. Most of this generation is required to cover critical load and provide MiniGrid resiliency (Carolina, Caguas, Ponce East (Jobos), Cayey and Mayaguez North).

San Juan 5 & 6 converted to gas in 2019. San Juan 6 is retired economically by 2035.

### 8.2.2 Capital Expenditures

Although for the cost calculations, we assumed that all new generation would be a result of an RFP process and hence the capital investments made by developers will be covered via a fixed cost component determined using the WACC and the economic life, the figure below shows the levels of capital expenditures required for the S4S2 Portfolio under Base Load forecast. These capital costs are all in and includes interest during construction but are expressed as an investment amount for the year the plants come online (not draw down). We observe that the largest investment is required for the generation assets expected to be in service in 2021 ($1.16 billion), for new solar, peaking generation and storage. Total capital investments reach $ 5.6 billion (US$ 2018) by 2038.

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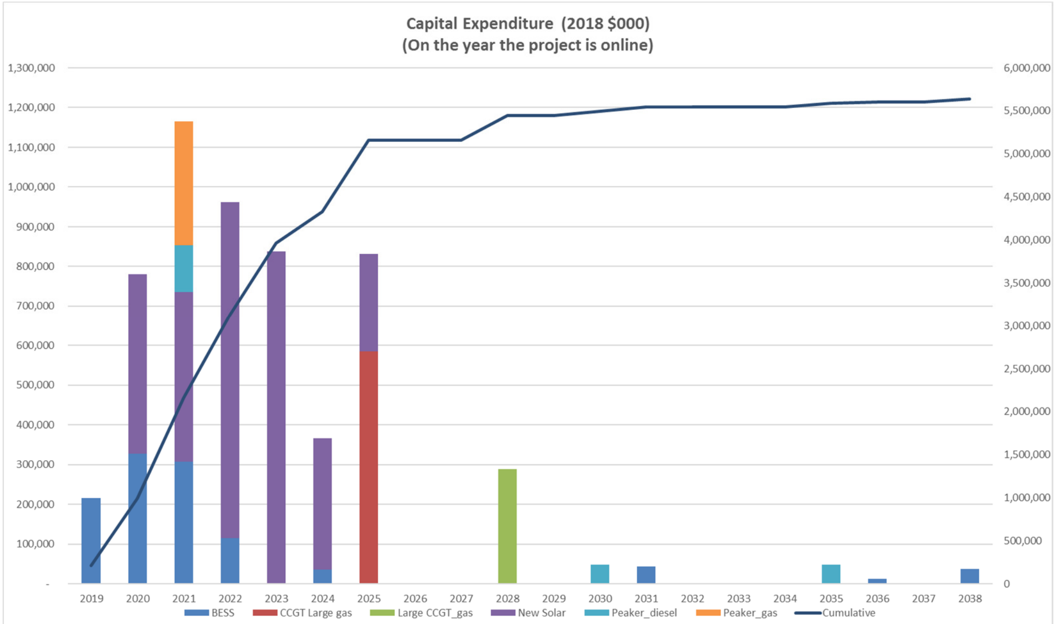
**Exhibit 8-5: S4S2 Portfolio Base Load Forecast Capital Expenditure**




| CapEx $000 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|
| BESS | 216,103 | 328,152 | 307,746 | 115,022 | - | 35,519 | - | - | - | - |
| CCGT Large gas | - | - | - | - | - | - | 585,827 | - | - | - |
| Large CCGT_gas | - | - | - | - | - | - | - | - | - | 288,353 |
| New Solar | - | 451,884 | 428,490 | 847,619 | 837,798 | 331,542 | 245,788 | - | - | - |
| Peaker_diesel | - | - | 116,769 | - | - | - | - | - | - | - |
| Peaker_gas | - | - | 312,088 | (0) | 0 | - | (0) | 0 | - | (0) |
| **Grand Total** | **216,103** | **780,036** | **1,165,094** | **962,641** | **837,798** | **367,061** | **831,614** | **0** | **0** | **288,353** |

## 8.2.3 Capacity Retirements

The installation of the PV and Storage in 2020, together with the long-term fall in demand allows for the economic retirement of Aguirre ST 1 and 2 (end of 2019), Palo Seco ST 3 (end of 2023) and San Juan Steam units 7 & 8 (end of 2023 & 2021, respectively). Palo Seco ST 4 is retired by the end of 2024 due to the entry in 2025 of the new combined cycle at Palo Seco.

Even under high load conditions, the Aguirre units are retired by the end of 2019, but the Palo Seco 3&4 and San Juan 7&8 units stay online until the end 2024, when they are retired by the entry of the large combined cycle at Palo Seco. Under low load conditions, the retirement plan stays mostly the same as under base case load.

EcoEléctrica is economically retired by the end of 2024, in spite of the reduction the fixed payments, and assuming the unit has more flexibility by allowing it to cycle on a weekly basis. This retirement is triggered by the entry of a new CCGT at Costa Sur (F-Class) and happens irrespective of the load forecast.

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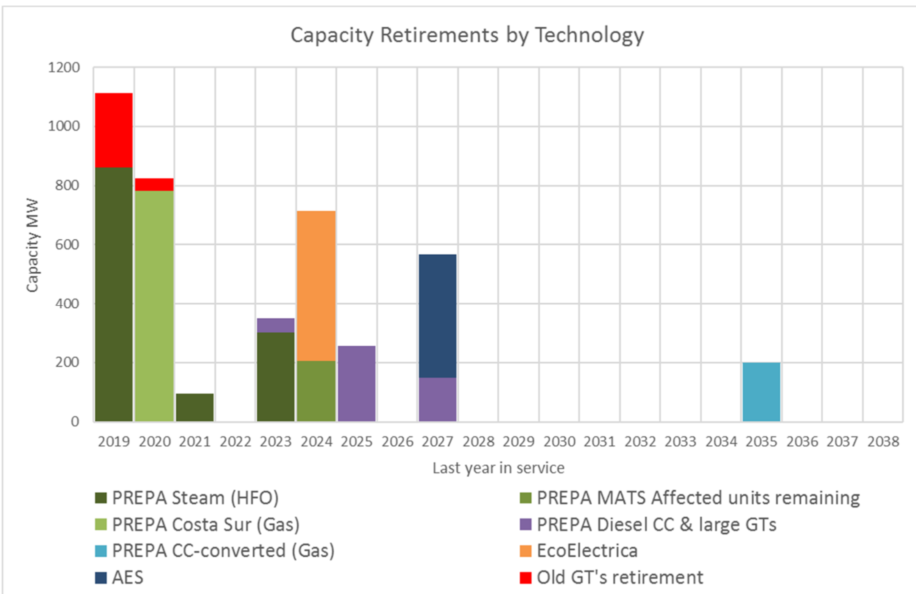
Costa Sur 5 & 6 last year in service is 2020 as it could not compete with EcoEléctrica, under the base load and low load forecast. Under the high load case, one of the units stays online longer until the end of 2021.

The Aguirre CC 1 is retired in 2025, but the other is maintained online for reserves. Cambalache units 2 & 3 retire in 2031 and 2023 respectively. The Aero Mayaguez peakers are all retired by the end of 2027 triggered by the entry of the new combined cycle in 2028 under this Portfolio and base load forecast and high load forecast. On the low load forecast the Aero Mayaguez is required (at least 100 MW), for local reserves to the end of the forecast.

AES is retired by 2028, not economically but by model input.

**Exhibit 8-6: Scenario 4 Capacity Retirements (last year in service**




| Technology / MW | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|
| PREPA Steam (HFO) | 862 | 0 | 95 | 0 | 300 | 0 | 0 | 0 | 0 | 0 |
| PREPA MATS Affected units remaining | | | | | | 206 | 0 | 0 | 0 | 0 |
| PREPA Costa Sur (Gas) | 0 | 782 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PREPA Diesel CC & large GTs | 0 | 0 | 0 | 0 | 50 | 0 | 257 | 0 | 150 | 0 |
| PREPA CC-converted (Gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EcoElectrica | 0 | 0 | 0 | 0 | 0 | 507 | 0 | 0 | 0 | 0 |
| AES | | | | | | | | | 416 | 0 |

Finally, the natural gas converted San Juan 6 is retired by 2035. San Juan 5 remains online under the base load forecast. Under a high load scenario, both units are retired earlier (in 2030 and 2032). In contrast, under a low load, both are maintained for the duration of the planning period. Based on the above, it can be concluded that these units are expected to remain online once converted, at least through the end of the decade.

Overall, the steam units running on fuel oil have costs above those of the combination of PV + Storage and their inflexibly would create curtailment, hence are retired.

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### 8.2.4 Future Generation Mix and Reserves

As shown in **Error! Reference source not found.**, the system transitions from one based on fossil fuel (mostly oil based) to one based on renewables. By 2038, 68% of the installed capacity in the system consists of renewable generation or facilities in place for its integration (battery storage), including solar and CHP distributed generation. Total renewable generation accounts for 47% of the total by 2038 with gas generation accounting for 48% of the total (see **Error! Reference source not found.**). Most of the gas generation comes from the three new large CCGTs and San Juan conversions. As such, the development of the LNG terminals is critical to reach the full potential of the new gas units.

As PREPA's units and the thermal PPOA's are phased out, the operating reserves decline from 79% in 2019 to a low of 44% by 2028 with the retirement of AES and three GTs at Mayaguez, despite the addition of the new CCGT in Mayaguez, as well. Operating reserves rise afterwards driven by the decline in load and the addition of 200 MW in peakers and storage in the last ten years. The Planning Reserve Margin of 30% appears not to have been binding constraint on the LTCE plan formulation in this scenario with the reserve margin of at minimum 37% through the forecast.

**Exhibit 8-7: Scenario 4 Installed Capacity Mix**

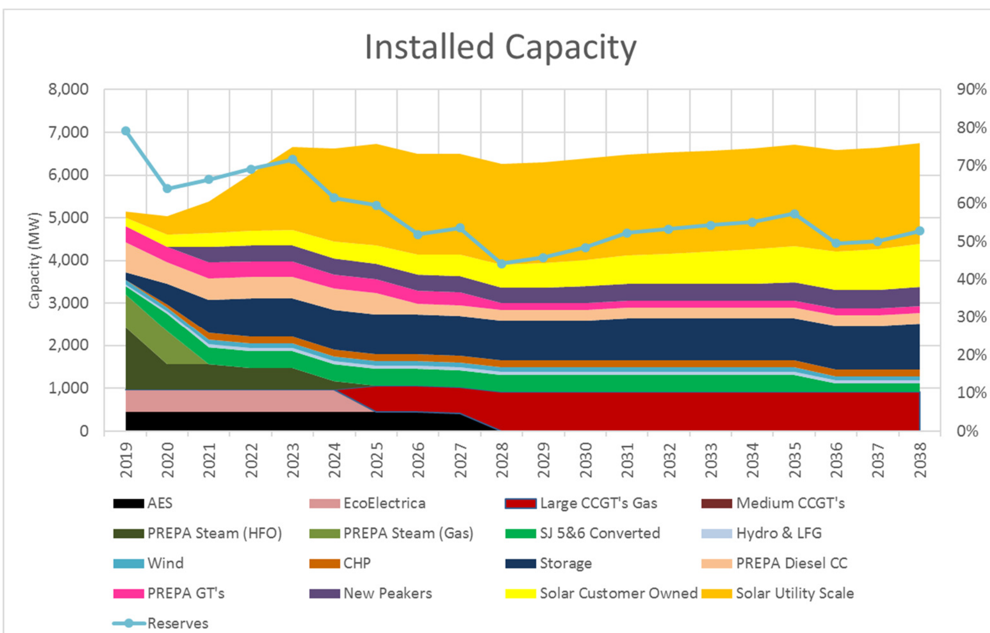

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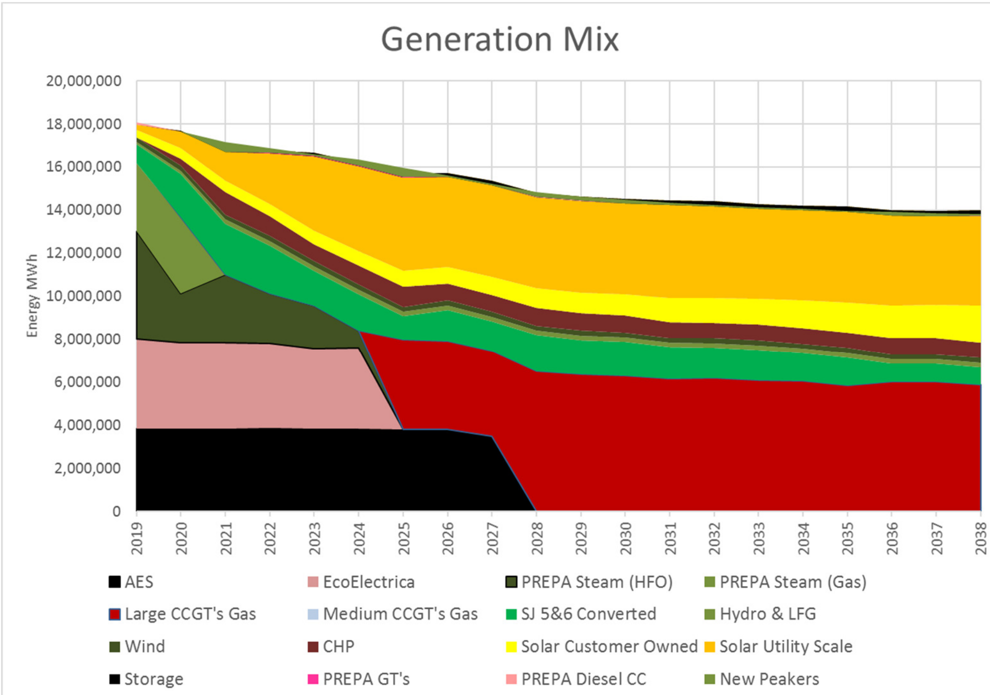
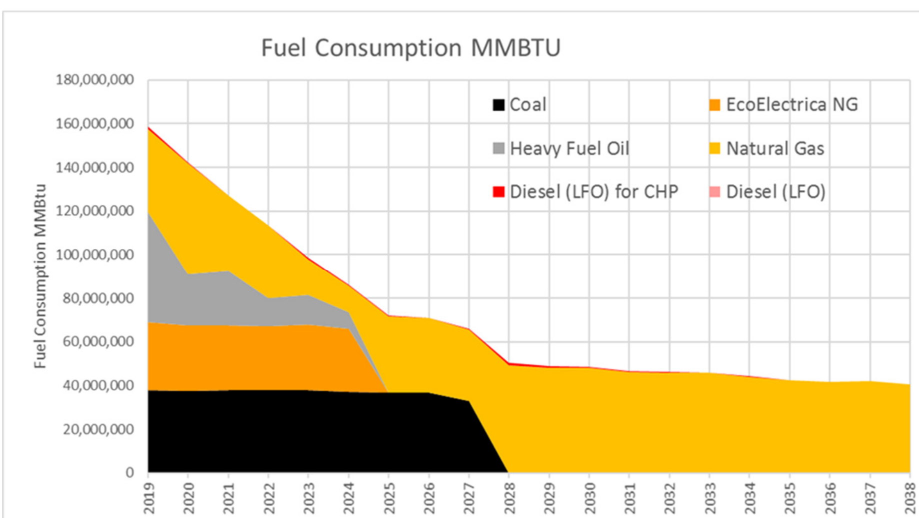
**Exhibit 8-8: Scenario 4 Future Generation Production Mix**




## 8.2.5 Fuel Diversity

In line with the change in the energy supply matrix, the system moves away from heavy fuel oil and coal to natural gas along with a sharp drop in overall fuel consumption and associated costs with the implementation of the plan. Fuel consumption declines with the retirements of old Steam gas and heavy fuel oil units and peakers along with EcoEléctrica's retirement by the end of 2024. Overall fuel consumption continues to fall through 2038 despite the new CCGTs in Palo Seco, Costa Sur and Mayaguez online in 2025-2028. Total fuel consumption drops 77% by 2038 with most of the fuel used coming from natural gas.

**Exhibit 8-9: Scenario 4 Fuel Consumption Trends**



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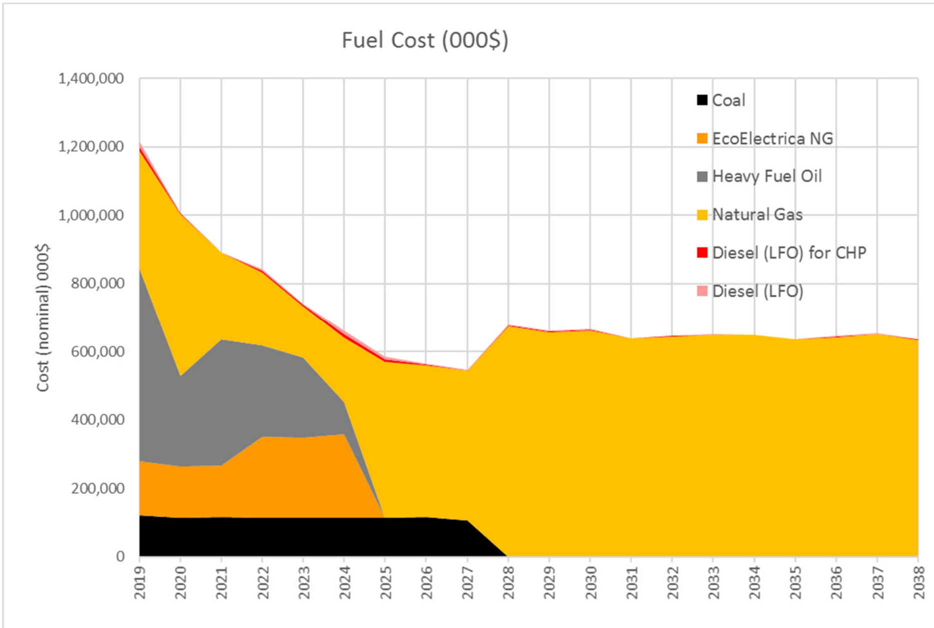
Fuel costs decline in line with the overall fall in fuel consumption falling to $445 million by 2027 (55% below 2019 levels. Fuel costs increase in 2028 with the F class CCGT built in Mayaguez, despite the retirement of AES in the same year. Fuel costs stay relative stable after 2028, on average at $645 million in the last ten years of the study period.

**Exhibit 8-10: Scenario 4 Fuel Costs**




### 8.2.6 RPS and Environmental Compliance

Plan is MATS compliant after 2024 and achieves 51% RPS compliance by 2038 under the base case load forecast (57% under high load and 47% under low load growth).

The renewable portfolio standard targets of 12% by 2022, 15% by 2027 and 20% by 2035 are all met and exceeded in the Scenario 4 base case, as well as the high and low load cases and under all strategies. The plan achieved 51% renewable penetration by 2038, reaching the proposed regulatory target of 50% renewable generation by 2040, two years earlier. Under the high load scenario, 57% of all generation comes from renewables with 2,580 MW of solar installations, while in the low load scenario 48% of all renewable generation comes from renewables with 2,100 MW of solar installations. Both cases, compared to 2,220 MW of solar installations under the base load.

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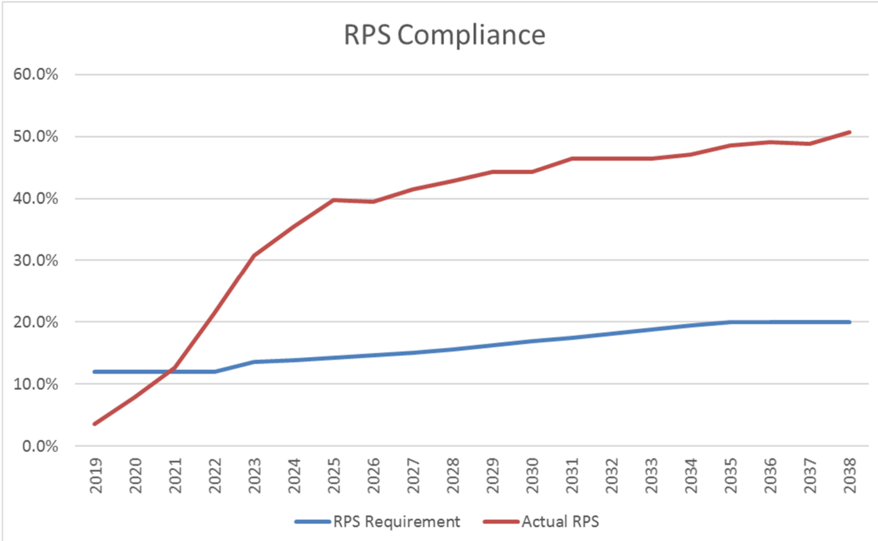
**Exhibit 8-11: Renewable Portfolio Standards**




CO2 emissions for PREPA's fleet fall in the first ten years of the forecast driven by the retirement of the older steam fuel oil, diesel and gas units along with increased penetration of solar generation. Emissions fall 50% by 2027 and further 20% more in 2028 with AES coal retirement. Emissions continue falling in after 2028 reaching a 76% reduction by 2038. The emission rate for the fleet falls from 1,343 lbs./MWh in 2019 to 495 lbs./MWh in 2038. As expected the most efficient units, the CCGTs have the lowest emission rates at 820 lbs./MWh. San Juan units converted to natural gas also show lower emissions rates at around 850 lbs./MWh as well as EcoEléctrica prior to retirement. The unit with the highest CO2 emission rates is AES coal at 2,155 lbs./MWh.

**Exhibit 8-12: CO2 Emissions PREPA System**

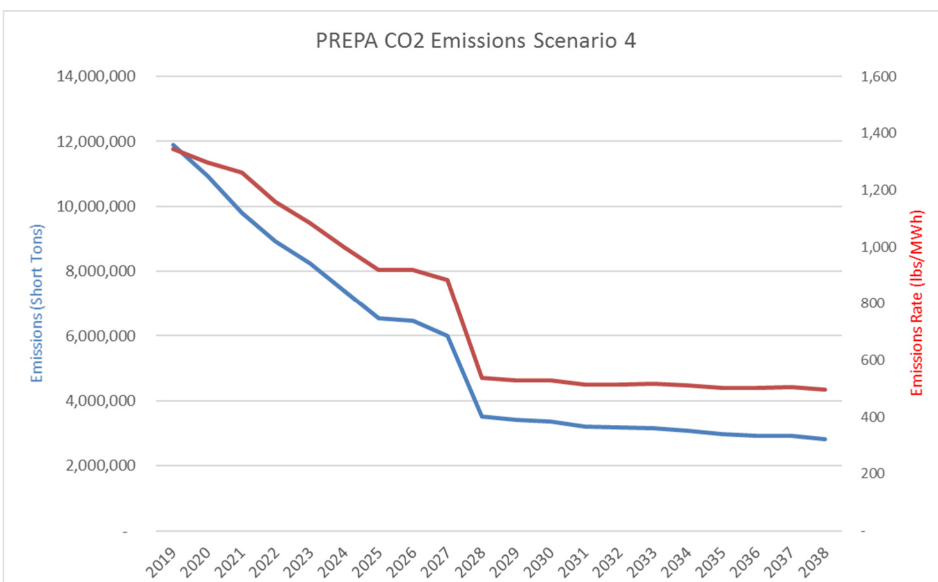


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**Exhibit 8-13: CO2 Emissions by Unit Type**

| *lb/MWh* | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|
| AES | 2,154 | 2,155 | 2,154 | 2,154 | 2,154 | 2,155 | 2,155 | 2,155 | 2,155 | - |
| EcoElectrica | 876 | 876 | 876 | 877 | 879 | 881 | - | - | - | - |
| Costa Sur 5&6 | 1,248 | 1,252 | - | - | - | - | - | - | - | - |
| Existing Fleet (HFO) | 1,426 | 1,721 | 1,666 | 1,664 | 1,690 | 1,660 | - | - | - | - |
| Diesel CC (LFO) | 93 | - | 1,335 | 1,335 | 1,335 | 1,335 | 1,334 | 1,335 | 1,335 | 1,335 |
| Existing GTs (LFO) | 1676 | 1759 | 0 | 1562 | 1611 | 1641 | 1488 | 0 | 0 | 0 |
| SJ 5&6 With NG | 857 | 852 | 851 | 850 | 849 | 850 | 849 | 851 | 850 | 851 |
| New CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 823 | 822 | 821 | 822 |
| New Peaker gas | 0 | 0 | 1200 | 1197 | 1206 | 1203 | 1202 | 1196 | 1194 | 1203 |
| New Peaker diesel | 0 | 0 | 2043 | 1894 | 1895 | 1799 | 1806 | 0 | 2043 | 1761 |
| **Total System** | **1,343** | **1,298** | **1,261** | **1,158** | **1,084** | **999** | **918** | **919** | **884** | **538** |

## 8.2.7 System Costs

The total cost of supply in real dollars including annualized capital costs, fuel costs, fixed and variable O&M is projected to decline with the implementation of the plan from $102/MWh in 2019 to $90.5/MWh by 2027 (real $2018), prior to AES Coal retirement, primarily due to the addition of solar and storage and the retirement of older generation. The costs increased in 2028 with AES retirement and the addition of the new CCGT later declining due to falling fuel costs to reach $93.1/MWh by 2038. Customer rates are expected to decline through 2027 under this plan.

The net present value of all operating costs reaches $10.4 billion for 2019-2028 (nominal @ 9% rate). Over the study period, the NPV is $14.5 billion. Note that the 9% discount rate (6.86% on a real dollar basis), is the same discount rate used in the first IRP and it is based on the assumption that PREPA (or its successors) is able to resolve its current financial issues and can borrow the capital at this rate. It should not be confused with the WACC which the weighted cost of capital for private parties that are assumed to invest in the resource additions.

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**Exhibit 8-14: Scenario 4 Production Costs**

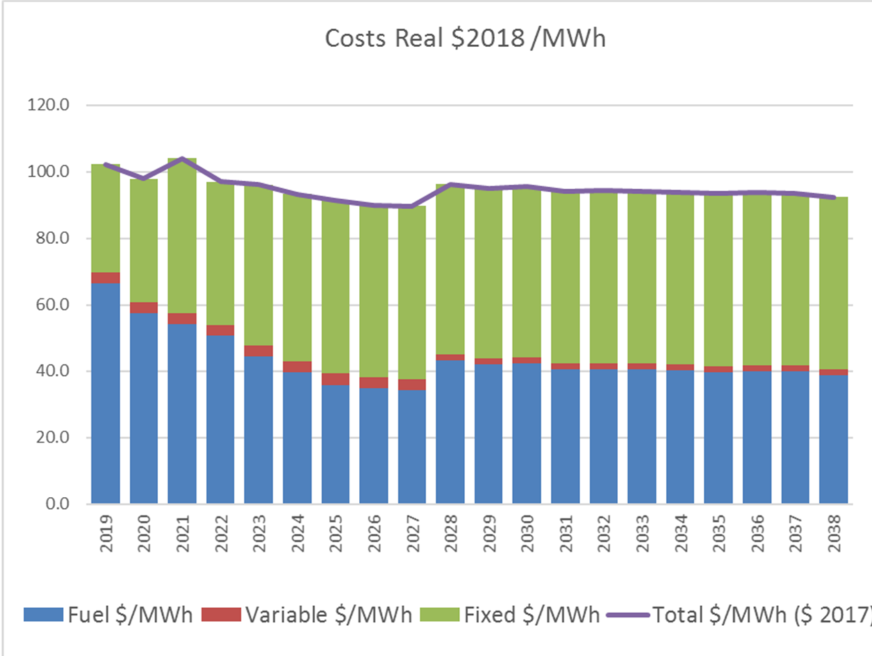


**Exhibit 8-15: System Costs High and Low Load Cases**

| Scenario | NPV @ 9% 2019-2038 $Millions | Average 2019-2028 2018$/MWh | NPV Deemed Energy Not Served MiniGrid Ops $Millions | NPV + ENS $Millions |
|---|---|---|---|---|
| Scenario 4 Base Load | 14,521 | 96.4 | 228 | 14,749 |
| Scenario 2 High load | 16,320 | 99.0 | 186 | 16,506 |
| Scenario 2 Low load | 13,467 | 96.7 | 225 | 13,692 |

Under the high load case, the production costs increase by $3/MWh on average with an NPV of $16.3 Billion, $1.8 billion higher than the base case. This is driven by an additional CCGT F class in San Juan build in 2029 to meet incremental loads in the north and a medium CCGT in Yabucoa in 2024. As discussed earlier, we are of the opinion that in the case the Strategy 3 expansion plan identified a better strategy.

Under the low load case, the average system costs are slightly higher compared to the base case but the overall NPV of the portfolio is lower at $13.4 billion. The reduction in costs is mostly driven by not building the Mayaguez F class in 2028, under the low load case.

### 8.2.8 Resiliency (MiniGrid Considerations)

A critical component of the formulation of the 2018 Integrated Resource Plan (IRP) is the identification of electrical islands or "MiniGrid" into which the system may be segregated after a major atmospheric event (e.g. hurricane). In other words, the MiniGrids are regions of the system that are interconnected with the rest of the electric power system via lines that may

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take over a month to recover after a major event, and should be able to operate largely independently, with minimum disruption for the extended period of time that would take to recover full interconnection. In addition to the MiniGrids, there are also microgrids located within some of the MiniGrids that will be isolated from the MiniGrid after a major event. The methodology for the initial definition of the MiniGrids and Microgrids is described on Appendix 1.

The Siemens team evaluated the potential cost of energy not served in the case of a hurricane impacting the island and placing the system under a mini-grid operation for one month while the transmission network is repaired. This cost is NOT a forecast of future cost, but rather a high-level determination of how the different portfolios resulting from the combination of scenarios and strategies would perform if every 5 years starting in 2022 a major hurricane impact the island resulting in the operation of the MiniGrids for one month ("Deemed Energy Not Served"). The Deemed Energy Not Served was determined based on the total forecasted load at each MiniGrid, including critical, priority and balance, and the generation that would be available from thermal and renewable resources, complemented by storage. For the costs of energy not served we took into consideration that during grid isolated operation the load shedding will be on an announced and rotating basis and targeting loads where the impact would be the least (typically residential loads), with limited duration. Thus, the Siemens team used a value of $ 2,000/MWh, about half of the lower expected cost for Puerto Rico (see Exhibit 7-22) and in line with the costs seen in another jurisdiction (see Exhibit 7-16).

As shown in **Error! Reference source not found.**, the net present value of the overall portfolio costs under the base case would increase by $228 million due to deemed energy not served. Under the high load case, the increase in portfolio costs is $186 million, and in the low load case $225 million. In the high case, the additional CCGT installations at San Juan and Yabucoa support mini-grid operation in these regions and reduce the overall potential costs of energy not served compared to the base case.

In Scenario 4, the critical and priority loads for the MiniGrid regions of Carolina, Caguas, Cayey, Arecibo, Mayaguez North and San Juan-Bayamon are not met with local generation while the plan is being developed in 2019 through 2022, as shown below for the Carolina MiniGrid. The total thermal maximum energy available including solar PV does not meet the critical, priority and balance loads through 2024 in Carolina (see Appendix 1 for more details on load generation balance and design of the MiniGrids).

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**Exhibit 8-16: Carolina Energy Coverage under a Minigrid Operation**

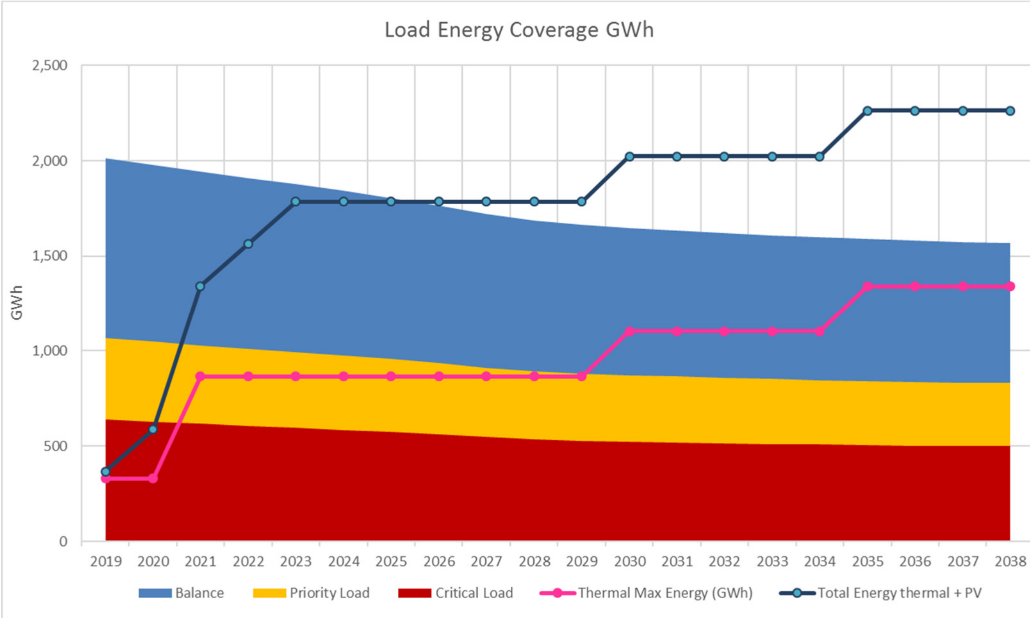


Exhibit 8-17 summarizes the present value of the cost of the "Deemed Energy Not Served" by MiniGrid region for Scenario 4 Strategy 2 and base load forecast.

**Exhibit 8-17: Present Value of Cost of Deemed Energy Not Served by MiniGrids**

| MiniGrid | NPV Cost ($000) |
|---|---|
| San Juan-Bayamon | $ 8,874 |
| Ponce | $ - |
| Carolina | $ 40,737 |
| Caguas | $ 127,850 |
| Arecibo | $ 25,110 |
| Mayaguez-North | $ 518 |
| Mayaguez-South | $ - |
| Cayey | $ 25,196 |
| Total | $ 228,285 |

The largest potential costs are for Caguas and Carolina, followed by Arecibo and Cayey.

### 8.2.9 Considerations under Strategy 3

Under strategy 3, at least 50% of the peak demand needs to be supplied with local generation. Under this strategy, the economic simulation yields a very similar expansion plan to Strategy 2. However, this strategy provides less flexibility and resiliency at the mini-grid level and for this reason has higher potential costs from energy not served, in case of a major disruptive hurricane.

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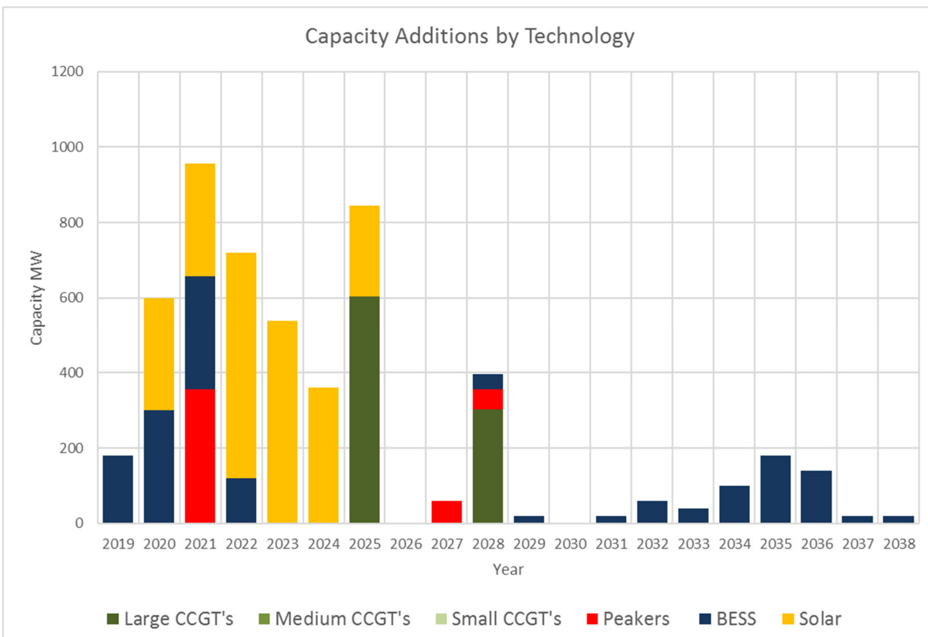
Under Strategy 3 and Base load forecast, the expansion plan is very similar with 1,200 MW of solar PV build in 2019-2022, maximizing the level of available solar PV capacity additions in this period. A total of 2,340 MW of solar PV is built during the study, only 120 MW higher than strategy 2 (see Exhibit 8-3).

There is 900 MW of battery storage build in 2019-2022 (in line with Strategy 2). In the long-term, there is an incremental 460 MW of battery storage build under this strategy. Two F class CCGTs at Palo Seco and Costa Sur are built in 2025 along with an additional F class at Mayaguez, the same as Strategy 2. In addition, 388 MW of peakers are built in 2019-2022 (likewise Strategy 2) with 471 MW in total over the study period.

Under the high case, an additional CCGT at Yabucoa is built in 2025, the same for the low case but in 2028. This is the major difference with respect of Strategy 2. In the low case, the CCGT at Mayaguez is not built.

**Exhibit 8-18: Capacity Additions Scenario 4, Strategy 3**




| Capacity by Technology MW | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|
| Large CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 604 | 0 | 0 | 302 |
| Medium CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Peaking Generation | 0 | 0 | 356 | 0 | 0 | 0 | 0 | 0 | 60 | 55 |
| BESS | 180 | 300 | 300 | 120 | 0 | 0 | 0 | 0 | 0 | 40 |
| **Total Distchable Additions** | **180** | **300** | **656** | **120** | **0** | **0** | **604** | **0** | **60** | **397** |
| Solar | 0 | 300 | 300 | 600 | 540 | 360 | 240 | 0 | 0 | 0 |
| **Total Additions** | **180** | **600** | **956** | **720** | **540** | **360** | **844** | **0** | **60** | **397** |

Retirements follow the same schedule of units retired as strategy 2, with the economic retirement of Aguirre ST 1 and 2 at the end of 2019, Palo Seco ST 3 and ST4 by the end of 2023 and 2024, respectively. San Juan units ST 7 & 8 are retired by the end of 2023 & 2021, respectively).

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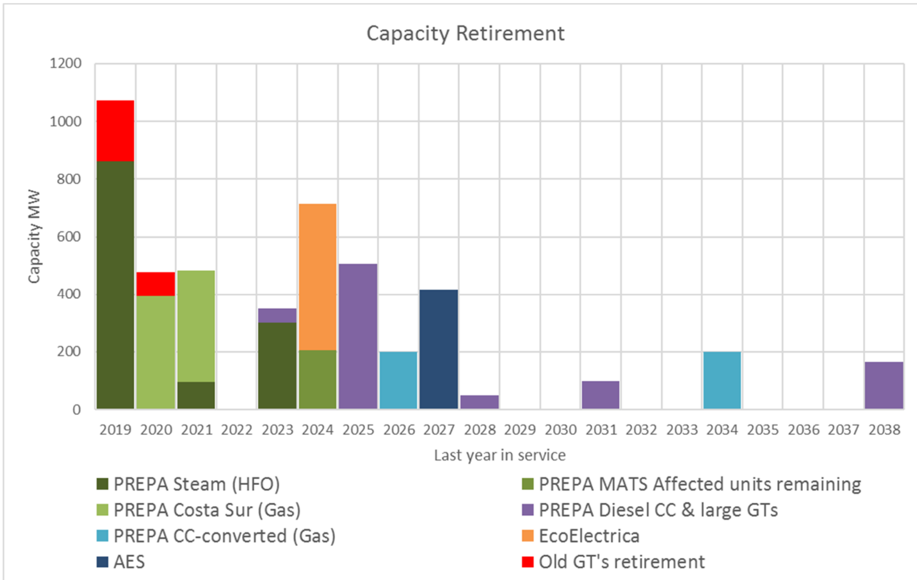
EcoEléctrica is economically retired by the end of 2024. Likewise, this retirement is triggered by the entry of a new CCGT at Costa Sur (F-Class) and happens irrespective of the load forecast. Costa Sur 5 & 6 last year in service is 2020 and 2021, respectively.

**Exhibit 8-19: Capacity Retirements Scenario 4, Strategy 3 (last year in service)**




| Capacity by Technology MW | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|
| PREPA Steam (HFO) | 862 | 0 | 95 | 0 | 300 | 0 | 0 | 0 | 0 | 0 |
| PREPA MATS Affected units remaining | | | | | | 206 | 0 | 0 | 0 | 0 |
| PREPA Costa Sur (Gas) | 0 | 393 | 388 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PREPA Diesel CC & large GTs | 0 | 0 | 0 | 0 | 50 | 0 | 506 | 0 | 0 | 50 |
| PREPA CC-converted (Gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 0 | 0 |
| EcoElectrica | 0 | 0 | 0 | 0 | 0 | 507 | 0 | 0 | 0 | 0 |
| AES | | | | | | | | | 416 | 0 |
| **Total Dependable Gen Retirement** | **862** | **393** | **483** | **0** | **350** | **713** | **506** | **200** | **416** | **50** |

Under this strategy, renewable penetration is slightly higher at 54% by 2038. Overall emissions decline over 70% by 2028, in line with strategy 2.

The overall portfolio costs are slightly higher under Strategy 3 at $14.6 billion, 96 million higher than Strategy 2. Including the potential costs of energy not served under mini-grid operations, the overall costs of the portfolio is $14.9 billion, at present value.

**Exhibit 8-20: Comparison Portfolio Costs Scenario 4 Base Load**

| Scenario | NPV @ 9% 2019-2038 $Millions | Average 2019-2028 2018$/MWh | NPV Deemed Energy Not Served MiniGrid Ops $Millions | NPV + ENS $Millions |
|---|---|---|---|---|
| Scenario 4 Strategy 2 Base Load | 14,521 | 96.4 | 228 | 14,749 |
| Scenario 4 Strategy 3 Base Load | 14,616 | 96.5 | 343 | 14,959 |

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At the regional MiniGrid level, the MiniGrids with the highest risk and potential costs of having load not served during a disruptive hurricane are San Juan-Bayamon and Caguas. As a result, the present value cost of deemed energy not served is $343 million, $124 million higher than Strategy 2. For this reason, Strategy 2 provides a lower cost plan with higher resiliency and reliability at the mini-grid level.

Under the high load case, strategy 3 is a lower cost strategy compared to the high load case under strategy 2 without the development of an additional CCGT as San Juan in 2029, as shown under strategy 2. Thus, the overall portfolio cost is $117 million lower, despite a greater potential cost from energy not served in the event a disruptive hurricane.

### 8.2.10 **Considerations under Strategy 1**

Strategy 1 is a centralized plan with no minimum generation requirements at the MiniGrid level. The surprisingly the Strategy produces an expansion plan that is slightly more expensive than strategy 2, which is Siemens' recommended plan, even before the cost of lack of resiliency is considered. A centralized plan has a greater risk and potential costs for unserved energy after a disruptive hurricane. The expansion plan is very similar to strategies 2 and 3 with more solar and battery storage generation (see Exhibit 8-3 S4S1B).

The expansion plan is very similar with 1,200 MW of solar PV build in 2019-2022, maximizing the level of available solar PV capacity additions in this period. A total of 2,340 MW of solar PV is built during the study period, only 120 MW higher than strategy 2.

There is 900 MW of battery storage build in 2019-2022 (in line with Strategy 2). In the long-term, there is an incremental 340 MW of battery storage build under this strategy. Two F class CCGTs at Palo Seco and Costa Sur are built in 2025 along with an additional F class at Mayaguez in 2028, in line with Strategy 2. In addition, 324 MW of peakers are built in 2019-2022 64 MW lower than Strategy 2 with 500 MW in total over the study period.

Retirements follow the same schedule of units retired as strategy 2, with the economic retirement of Aguirre ST 1 and 2 at the end of 2019, Palo Seco ST 3 and ST4 by the end of 2024 and 2021, respectively. San Juan units 7 and 8 units are retired by the end of 2024.

EcoEléctrica is economically retired by the end of 2023, a year earlier compared to Strategy 2. Likewise, this retirement is triggered by the entry of a large CCGT at Costa Sur (F-Class) in 2025. Costa Sur 5 & 6 last year in service is 2020 and 2022 as it could not compete with EcoEléctrica.

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**Exhibit 8-21: Capacity Additions Scenario 4, Strategy 1**

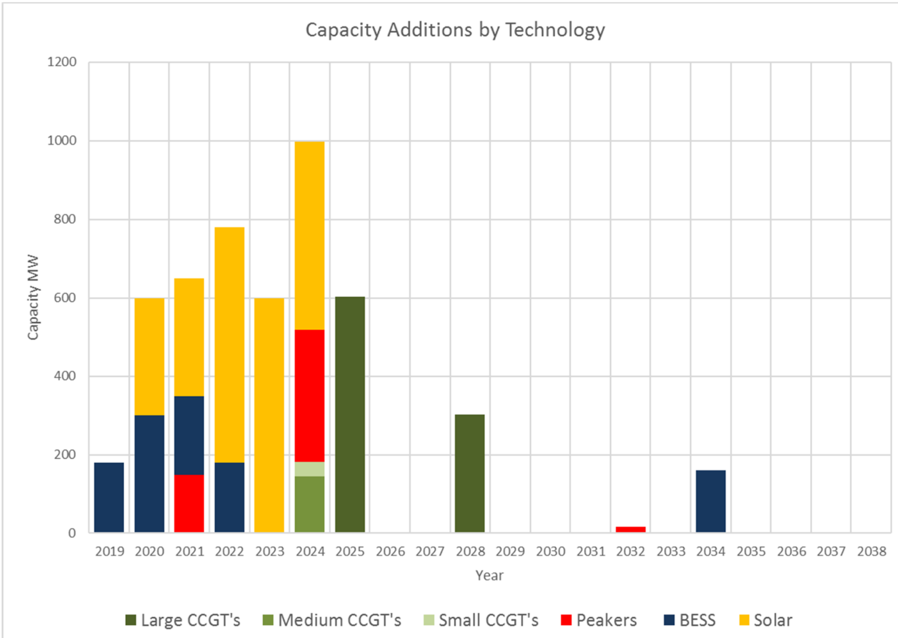
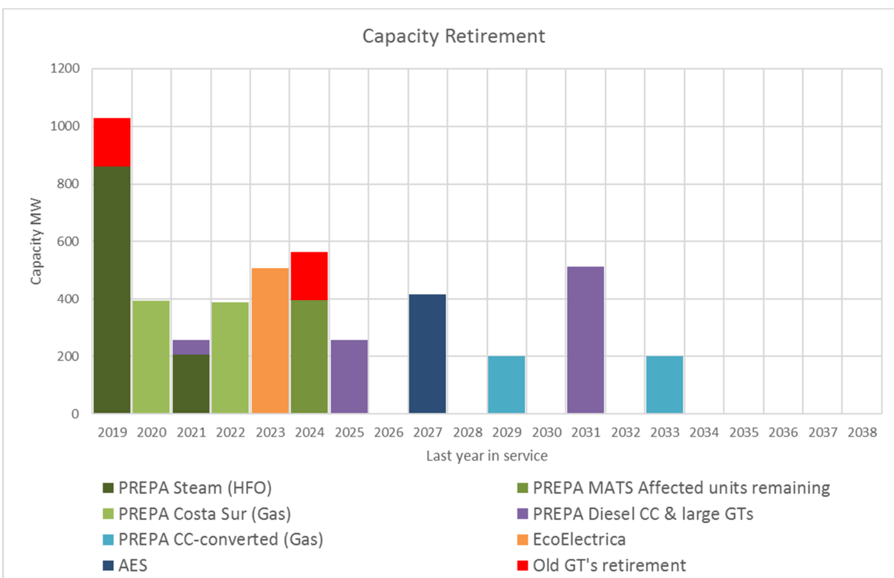



**Exhibit 8-22: Capacity Retirements Scenario 4, Strategy 1**




The overall portfolio costs are higher under this strategy driven by higher operating costs and potential costs from Deemed Energy Not Served under a mini grid operation in the event of a major hurricane. Portfolio costs are $405 million higher, compared to strategy 2 and $195 million higher, compared to strategy 3.

The potential for unserved energy arises in most MiniGrid regions, except for San Juan-Bayamon and Ponce. The regions with highest potential costs from unserved energy under MiniGrid operations are Carolina, Caguas and Arecibo.

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**Exhibit 8-23: Comparison Portfolio Costs Scenario 4 Strategy 2, 3 and 1**

| Scenario | NPV @ 9% 2019-2038 $Millions | Average 2019-2028 2018$/MWh | NPV Deemed Energy Not Served MiniGrid Ops $Millions | NPV + ENS $Millions |
|---|---|---|---|---|
| Scenario 4 Strategy 2 Base Load | 14,521 | 96.4 | 228 | 14,749 |
| Scenario 4 Strategy 3 Base Load | 14,616 | 96.5 | 343 | 14,959 |
| Scenario 4 Strategy 1 Base Load | 14,678 | 97.3 | 477 | 15,154 |

Under this strategy, the renewable portfolio standards are met with a 51% renewable generation by 2038.

### 8.2.11 Sensitivities Considerations

The Siemens team evaluated 4 sensitivities under scenario 4 to isolate the impacts of certain important variables while holding other assumptions constant. For the 2018 IRP, four sensitivities were modeled.

*Sensitivity 3:* Economic retirement of AES Coal and EcoEléctrica regardless of contract term.

Under Sensitivity 3, AES is not retired on an economic basis and continue operating through 2038. The unit is a low-cost plant dispatching at $76/MWh on average during the study period and capacity factors higher than 93%. With AES coal staying online, the CCGT at Mayaguez is not developed, as in happens under strategies 2 and 3 in 2028.

EcoEléctrica retires at the end of 2024, in line with strategy 2 and 3 under base load. Under this sensitivity, the two F class at Palo Seco and Costa Sur are also developed in 2025. Overall, there is over 2,160 MW of solar build supported by 1,020 MW of battery storage (see Exhibit 8-3 S4S2S3B).

Overall portfolio costs are $241 million below the portfolio costs under the base case (strategy 2), driven by lower fuel, variable and capital costs. However, fuel consumption is 75% higher under this sensitivity with thermal generation accounting for 52% of total generation.

The renewable portfolio standards are met with 47% of total generation coming from renewables. However, there is in increase in curtailment levels reaching 5% by 2038, compared to 1%, under the base case, due to the inflexibilities of the AES coal plant.

Overall emissions are 93% higher compared to the base case with an overall emissions reduction of 54% by 2038.

*Sensitivity 4:* Ship-based LNG at San Juan could achieve permitting approval. The ship-based LNG at San Juan can basically supply the conversion of San Juan 5 and 6 and

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provide limited gas to other developments. It has reduced capacity in comparison to the land-based LNG option.

Under Sensitivity 4, there is more gas generation added to the system. The Sensitivity installs in addition to the CCGT's for the base case (S4S2) one additional F class CCGTs at Yabucoa in 2025 and the CCGT at Costa Sur is online in 2027. Solar and battery storage installations are slightly higher with 120 MW and 140 MW more, respectively by 2038 (see Exhibit 8-3 S4S2S4B).

With more availability of gas, the Aguirre CC2 stays online through the study period, as well San Juan unit 5 conversion. San Juan 6 retires until 2035, nine years compared to the base case.

Overall portfolio costs are about 93.0 million higher under this sensitivity, driven by higher CapEx and fuel costs. This case also has higher potential costs from unserved energy during a hurricane event.

*Sensitivity 5:* High gas prices.

As in the base case, both the F class at Palo Seco and Costa Sur are found economic to be in place in 2025. Under this sensitivity, the simulation favors the development of 393 MW of additional gas-fired peakers (90% more), in addition to a medium CCGT at Yabucoa. The medium CCGT is developed, instead of a large CCGT at Mayaguez. Solar and battery storage installations are similar to the base case (see Exhibit 8-3 S4S2S5B).

Under a high gas price scenario, EcoEléctrica stays online through the study period. Both of Aguirre CCs are retired as well as both of San Juan converted units, the last which get retired in 2036. AES is scheduled to be retired in 2027 but if it would not under a high gas price scenario, the economics will be more robust.

Overall portfolio costs are $1 billion higher under a high gas price scenario at $15.8 billion over the study period (at present value). The increase is driven by higher fuel costs, the continuation of EcoEléctrica and capital payments with the development of more peakers. The risk to the portfolio from higher gas prices is significant.

*Sensitivity 6:* High cost of renewables

Under this sensitivity, there is a significant reduction in solar installations with only 780 MW of solar PV installed over the study period, 1,400 MW below the base case. Batteries to support the solar developments are reduced as well by 460 MW to 620 MW. The RPS targets are met through 2035 but the long-term target of 50% by 2040 falls significantly short to only 22% renewable penetration by 2038 (compliance with current regulations is achieved). CO2 emissions in this case are 38% higher by 2038, compared to the base case and overall emissions reductions are 67% over the study period.

There is more gas capacity installed with 1,200 MW of new large CCGTs installed, including an F class at Mayaguez in 2025 (3 years earlier than the base case) and an F class in San Juan in 2028 (installation only seen in high load cases). In addition, there is a medium CCGT developed in Yabucoa in 2024 (see Exhibit 8-3 S4S6S6B).

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Overall portfolio costs are $935 million higher, mostly driven by $1.1 billion more in fuel costs and CapEx, partially offset by lower variable and fixed costs. The potential costs from energy not served under MiniGrid operation is lower by $62 million, compared to the base case with more gas available locally in some regions.

### 8.2.12 Rate Impact

In the sections above, we presented the composition of least cost portfolio formulated under Scenario 4. In this section we estimate the potential impact of the S4S2B portfolio on the final rates to customers and compare the resulting final rates with the possible costs that the customers would incur for self-supply as described in Appendix 4 Demand-Side Resources and that basically include:

a) Residential Solar Photo-Voltaic (PV), use of net-metering
b) Grid-Defection; PV plus storage at levels that allowing become an autonomous self-supplier.
c) Combined Heat and Power (CHP)
d) Diesel Generator

#### 8.2.12.1 Rate Components

We provide below a high-level description of the individual components that make up the final rates resulting from the S4S2 generation portfolio.

The final customer rate can be broken down into at least three basic components:

a) Generation cost of energy delivered to the customers (generation)
b) Non-generation utility component (transmission & distribution)
c) Balance non-bypassable component (debt repayment)

The generation rate component is directly dependent upon the Capital, Fixed Operating and Maintenance (FO&M), Regasification, Fuel, and Variable Operating and Maintenance (VO&M) costs incurred in building and operating the generation portfolio. This component is portfolio specific and will change as the generation asset mix changes. Also, this rate reflects the total generation needed to serve the customer load accounting for the technical and non-technical losses in the transmission and distribution network and PREPA's internal self-consumption. The Portfolio includes a certain amount of customer self-supply and the total generation is reduced by this self-supply for the purposes of calculating the costs.

The non-generation utility component is PREPA's Non-Fuel and Power Purchase (non-F&PP) rate less the non-bypassable component included in the non-F&PP rate. This component reflects the transmission and distribution costs and is held constant across generation portfolios for this analysis. It should be noted that this component does not include any additional costs for the T&D debt repayment beyond those provided by the fiscal plan.

Finally, the third basic component is PREPA's Non-Bypassable Non-F&PP rate that reflects PREPA's existing debt service costs. Needless to mention, this component is static and does not change with the portfolio asset mix.

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The final resulting rate for the case is computed as the sum of the three individual components described above and is then compared with the cost of customer-based alternatives.

#### 8.2.12.2 Results of Comparison to Customer Based Alternatives

In this section we describe the results of the analysis we performed comparing the final S4S2 rates to unit costs for customer-based alternatives.

From the results, which are illustrated in Exhibit 8-24, we have the following observations and inferences:

- The unit costs for all the customer alternatives considered are lower than the final all-in S4S2 generation portfolio rate.
- The levelized cost of customer level is higher than the cost of the generation delivered to de customer and that includes the effect of loses until 2028 (when AES Coal retires). However, this cost is significantly lower than the total rate even before the non-bypassable component and confirms the assumption in the DG forecast that the continuance of 'net-metering' rates will incur customer side roof top PV in line with the high adoption rates observed to date.
- These results also indicate that, given PREPA's non-bypassable rate component forecasted, coupled with the expected reduction in renewable generation costs, the customers may be motivated to self-supply if they are able to raise the capital investment required for installing the self-supply option or if a developer installs the equipment and recovers the investment through leases or other financing options.
- It is also interesting to note that when the Non-Bypassable charge is added to the case where the customer only has PV and uses PREPA as a bank (net-metering) the costs are very similar to the complete self-supply option. However, in this case there is an added advantage of no need for the initial capital outlay. So, provided that the PREPA service meets the reliability expectations of the customer, it can be reasonably concluded that the customer will continue to be connected to the PREPA grid.

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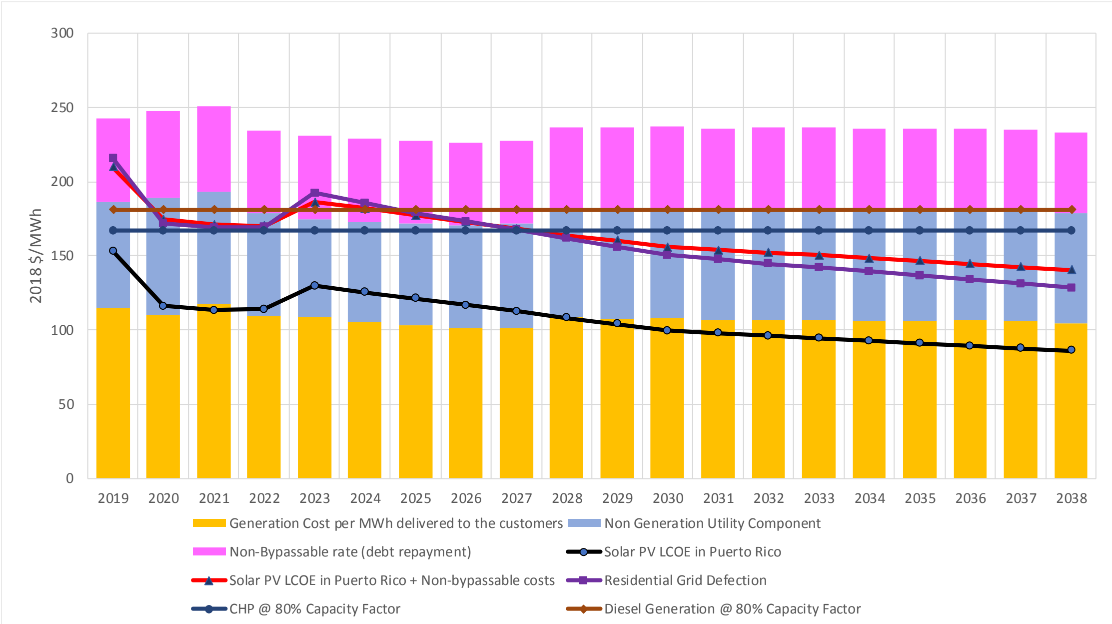
**Exhibit 8-24:Final S4S2 Generation Portfolio Rates Compared to Unit Costs of Customer Alternatives**

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We analyzed another case where we reduced the non-technical losses to typical values observed in the US (0.5% or less). The resulting final rate for the S4S2 generation portfolio, also reduces, but not to the extent that our above observations and inferences change. This updated comparison chart is given in the exhibit below.

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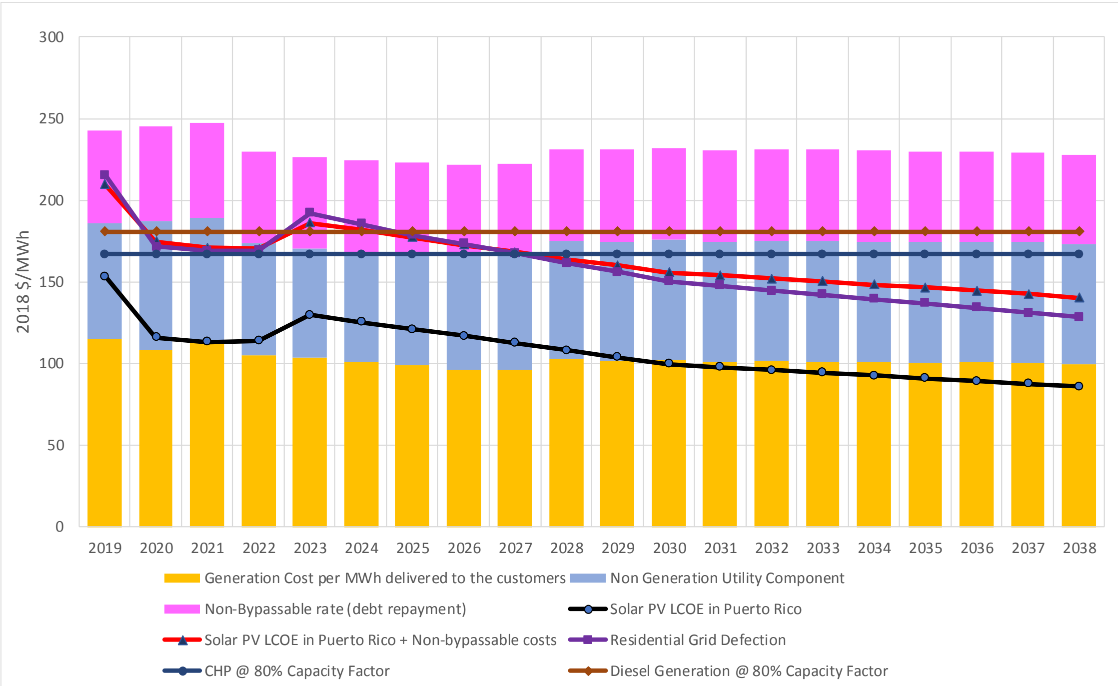
**Exhibit8-25: Final S4S2 Generation Portfolio Rates Assuming Reduced Losses**




## 8.2.13 Nodal Analysis Scenario 4

The Siemens team evaluated the least cost plan under Scenario 4 using a nodal simulation. The objective is to identify the effects of transmission on the key metrics of technical losses, production costs, renewable curtailment and energy not served.

The results of the nodal runs show that in the first 10 years (2019 – 2028) the production costs of the nodal runs match very closely with those of the zonal runs used for the LTCE assessment (see Exhibit 8-26). The losses in each of the nodal cases was less than that of the zonal runs used, due to the more accurate modeling of the transmission system. On average the reduction in losses is 0.8% as shown in Exhibit 8-27.

The amount of curtailment observed for the new solar generation was higher in the Nodal runs towards the end of the model period as shown in Exhibit 8-26, but this was found to be not related with transmission but rather with differences in the strategies for the dispatch of the storage used in the nodal runs.

There was no energy not served in the nodal runs, which is in line with the results of the zonal runs.

In summary the minimal impact of transmission was expected due to the greater distribution of generation resources and reduced load.

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**Exhibit 8-26: Production Costs Nodal vs. Zonal and Renewable Curtailment**

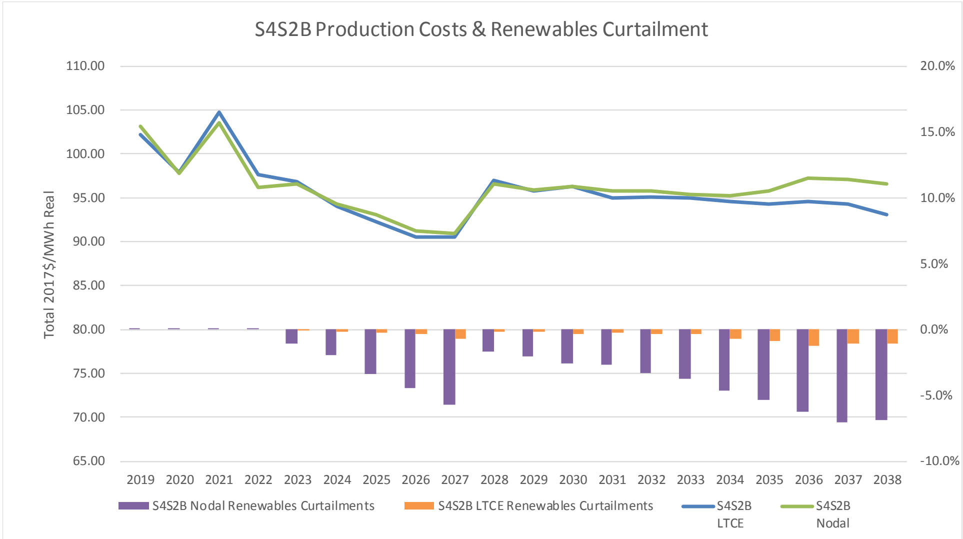


**Exhibit 8-27: Transmission Losses Differences**

| Loss Difference | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LTCE Losses | 3.8% | 3.2% | 1.9% | 1.9% | 1.9% | 2.0% | 1.4% | 1.4% | 1.4% | 0.7% | 0.7% | 0.7% | 0.7% | 0.7% | 0.7% | 0.7% | 0.6% | 0.7% | 0.8% | 0.7% |
| NODAL Losses | 1.1% | 1.0% | 0.6% | 0.6% | 0.6% | 0.6% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% |
| **DIFFERENCE** | **2.6%** | **2.2%** | **1.3%** | **1.3%** | **1.3%** | **1.4%** | **1.0%** | **0.9%** | **0.9%** | **0.2%** | **0.2%** | **0.2%** | **0.2%** | **0.2%** | **0.2%** | **0.2%** | **0.2%** | **0.3%** | **0.3%** | **0.2%** |

## 8.3 The ESM Plan

The Energy System Modernization Plan (ESM) is a plan developed by PREPA based on several generation expansion additions, and it is to be assessed on the IRP as a Central Scenario. The purpose of the ESM Plan is to expedite the implementation of a preferred plan utilizing procurement options presented by the Public Private Partnership Authority, identify the pricing structure necessary to retain existing natural-gas fired generation in the south, consider locational alternatives for new large scale CCGTs, and ensure reliable capacity in the San Juan area. The corresponding least cost long term capacity expansion plan (LTCE) is developed taking into consideration some pre-defined decisions as described below. This plan is to be compared with the applicable least cost plan (Scenario 4, strategy 2) under base load forecast

The ESM is based on the following fixed decisions:

- Replacement of all 18 existing Frame 5 GT's with new mobile units GTs (23.8 MW each) as a fixed decision to come online by 2021 and with containerized LNG as a fuel option (418 MW total).

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- Development of an LNG terminal at Yabucoa (Caguas) and a 302 MW F-Class CCGT in June 2025 to be built as a fixed decision.
- Development of an F-Class CCGT at Palo Seco by 2025 fueled by a land-based LNG at San Juan
- New ship-based LNG at Mayaguez and conversion to dual fuel of the Aero Mayaguez units (4x50MW) as a fixed decision. In addition, as an option, the case includes the possibility of building a 302 MW F-class CCGT at Mayaguez. The last option was not selected by the LTCE.
- Development of a new 114 MW thermal plant (combined cycle assumed 3x38 MW) burning natural gas in the San Juan area.

The following assumptions were also included in the simulation of this scenario:

- Load Forecast is treated via a Base, High and Low case.
- EcoEléctrica is assumed to stay in service but with the fixed payment reduced to 60% (new 2022 payment $88 million down from $240 million the prior year). This reduction is enough for it to be competitive with the CCGT option. The unit is assumed to be fully flexible for cycling.
- AES is assumed to expire in 2027, in line with the least cost plan.
- Solar and storage costs and availability based on reference case assumptions. Solar PV is limited to 240 MW in 2021, 480 MW in 2022-2023, 300 MW in 2024 and 480 MW after 2024. Storage is limited to 20 MW in 2019, 100 MW in 2021 and 160 MW onwards.
- San Juan units 5 & 6 are converted to natural gas in June 2019 (in line with the least cost plan). San Juan units are subjected to a capacity payment of $5 million per unit until 06/30/2024, on an annual basis. Afterwards, the capacity payment is zero. San Juan units are subjected to fuel constraints at San Juan (ship-based fuel constraint for July 2019-June 2025, and land-based LNG constraint from July 2024 through the end of the planning period.
- Energy Efficiency as per the requirement of Regulation No. 9021, i.e., 2% per year of incremental savings attributable to new energy efficiency programs for 10 years.
- Minimum RPS targets of 12% by 2022, 15% by 2027 and 20% by 2035.

### 8.3.1 Generating Additions

The economic simulation of the ESM case results in 900 MW of utility scale PV additions over the planning period. A total of 720 MW is added in 2020-2022, 480 MW below the least cost Scenario4. Similar capacity is installed under the high and low load cases during this period. By 2023 the ESM plan installs all 900 MW of solar PV capacity.

800 MW of battery energy storage is built over the planning period, about one half of the total installed in 2019-2022. The ratio of solar PV to battery storage is much higher in the ESM case compared to the least cost plan under Scenario 4 (0.88 MW per 1 MW of solar in ESM vs. 0.4 MW per 1 MW in the least cost plan).

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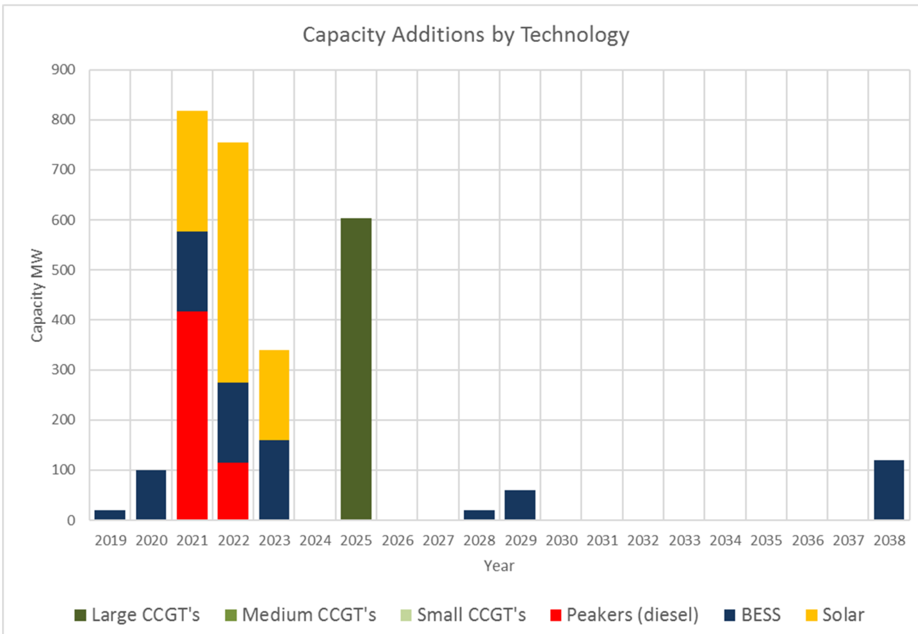
The thermal additions are largely the ones identified as an input to the plan, with the exception an small diesel CCGT is installed at Ponce east by 2035. The plan does not develop the new CCGT at Costa Sur, as it assumes EcoEléctrica to continues as indicated above.

The peaking generation added provides MiniGrid resiliency, in particular for Carolina, Caguas, Cayey, Ponce (Jobos) and Mayaguez North.

**Exhibit 8-28: ESM Plan Capacity Additions**




| Capacity by Technology MW | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Large CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 604 | 0 | 0 | 0 | 0 |
| Medium CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small CCGT's (LPG enabled) | 0 | 0 | 0 | 114 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Peakers (diesel) CT's and CCGTs | 0 | 0 | 418 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| BESS | 20 | 100 | 160 | 160 | 160 | 0 | 0 | 0 | 0 | 20 | 60 |
| **Total Distchable Additions** | **20** | **100** | **578** | **274** | **160** | **0** | **604** | **0** | **0** | **20** | **60** |
| Solar | 0 | 0 | 240 | 480 | 180 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Additions** | **20** | **100** | **818** | **754** | **340** | **0** | **604** | **0** | **0** | **20** | **60** |

## 8.3.2 Capacity Retirements

The installation of the PV and Storage in 2020 allows for the economic retirement of Aguirre ST 1 and 2 (end of 2019 & 2020), Palo Seco ST 3 & 4 in 2024 and San Juan ST 7 & 8 in 2023.

EcoEléctrica is modelled to stay in service and the adjustment to the contract was determined for it to be competitive with a CCGT. The fixed payments are reduced to about 40% of current values and the unit is assumed to be able to cycle as required to accommodate the renewable.

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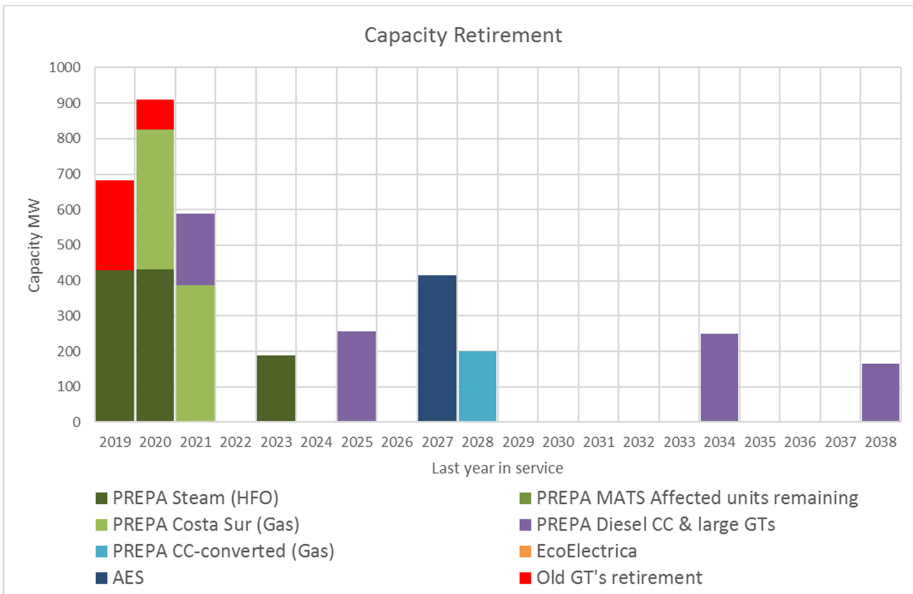
Costa Sur 5 & 6 last year in service are 2021 and 2020, respectively, retired by the fall in load and the entry of solar PV and Storage.

AES is retired at the end of 2027, not economically but by model input.

The Aguirre CC unit 1 is retired in 2025 and unit 2 later in 2034. The four units of Aero Mayaguez are converted to gas by 2022 and stay online through the planning period. The Cambalache units stay online for reserves and MiniGrid support.

Finally, the natural gas converted San Juan 5 stays online through the planning period, while San Juan 6 is retired in 2028.

**Exhibit 8-29: ESM Capacity Retirements (last year in service shown)**




| Capacity by Technology MW | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PREPA Steam (HFO) | 429 | 432 | 0 | 0 | 189 | 0 | 0 | 0 | 0 | 0 | 0 |
| PREPA MATS Affected units remaining | | | | | | 0 | 0 | 0 | 0 | 0 | 0 |
| PREPA Costa Sur (Gas) | 0 | 393 | 388 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PREPA Diesel CC & large GTs | 0 | 0 | 200 | 0 | 0 | 0 | 257 | 0 | 0 | 0 | 0 |
| PREPA CC-converted (Gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 0 |
| EcoElectrica | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| AES | | | | | | | | | 416 | 0 | 0 |
| **Total Dependable Gen Retirement** | **429** | **826** | **588** | **0** | **189** | **0** | **257** | **0** | **416** | **200** | **0** |

## 8.3.3 Future Generation Mix and Reserves

During the planning, under the ESM portfolio, the system moves away primarily from coal and oil to natural gas and renewables. By 2038, 53% of the installed capacity in the system consists of renewable generation or facilities in place for its integration (battery storage). This number includes customer driven distributed solar. However, total renewable generation is only 29% of the total compared to 47% in the least cost plan (see **ERROR! REFERENCE SOURCE NOT FOUND.**). Most of the gas generation comes from the two new large CCGTs and EcoEléctrica. As such, the development of the LNG terminals is critical for the feasibility of the new gas units.

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As PREPA's units and the thermal PPOA's are phased out, the operating reserves decline from 73% in 2019 to a low of 51% by 2029 with the retirement of AES coal. Operating reserves rise gradually afterwards driven by the decline in load and the medium diesel CCGT. The Planning Reserve Margin was not found to be binding at any time on the LTCE decisions.

**Exhibit 8-30: ESM Future Installed Capacity Mix**

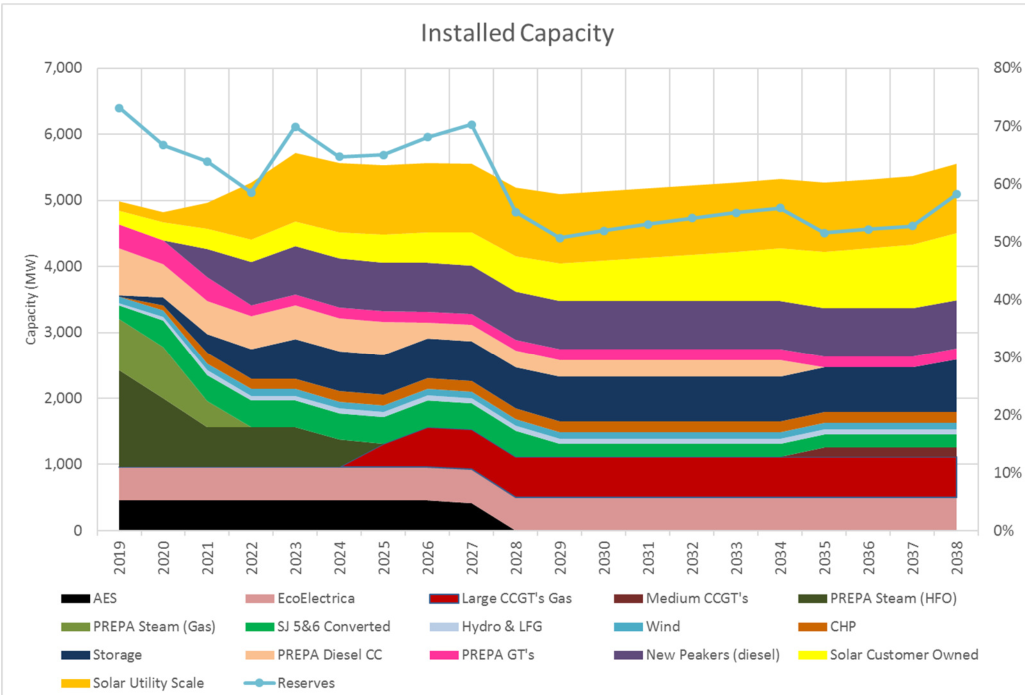

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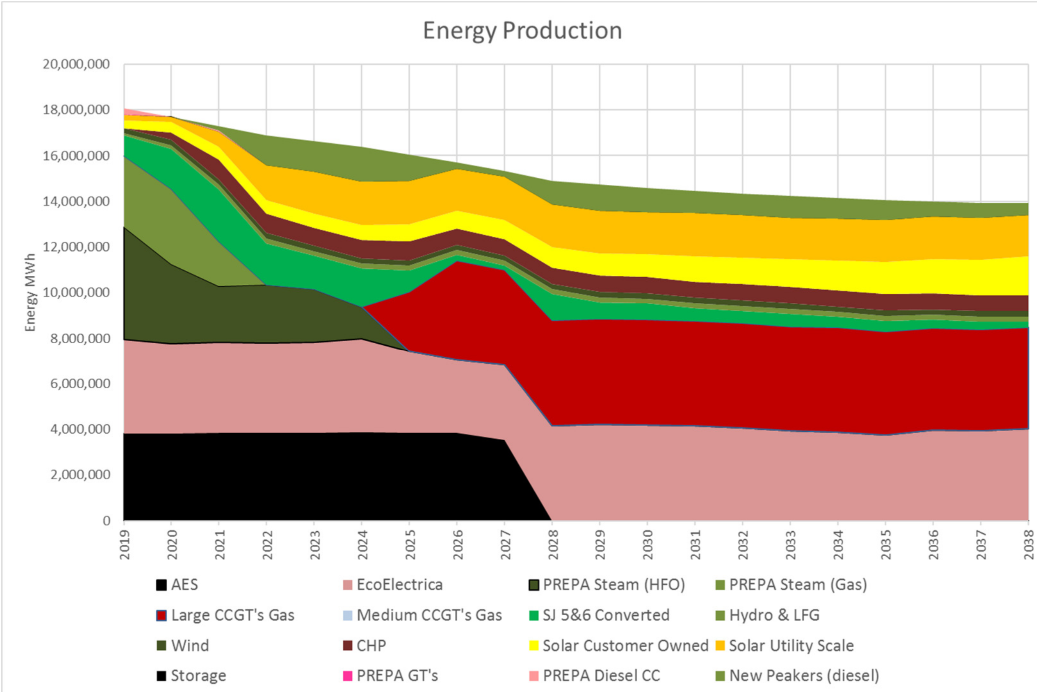
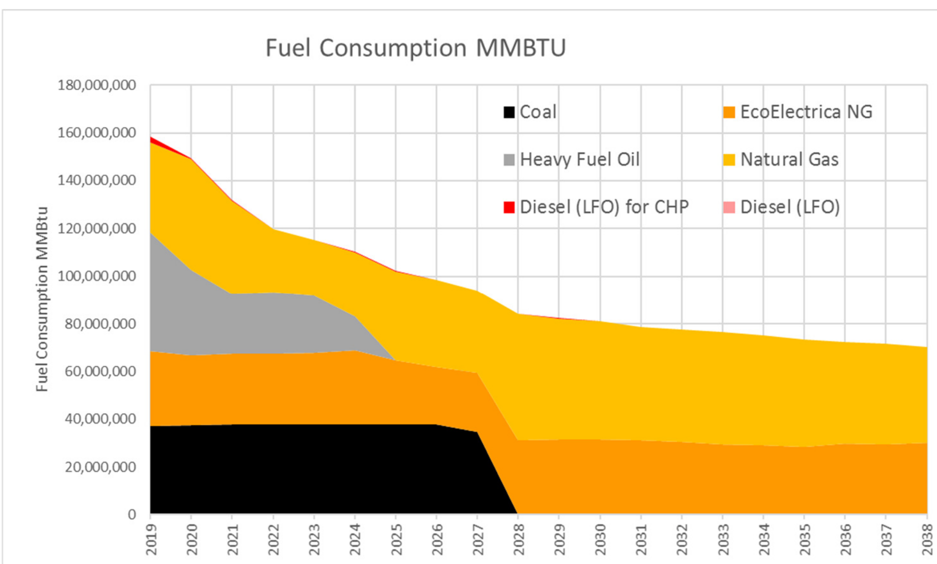
**Exhibit 8-31: ESM Future Generation Mix**




## 8.3.4 Fuel Diversity

In line with the change in the energy supply matrix, the system moves away from heavy fuel oil and coal to natural gas. There is a significant decline in the overall fuel consumption and associated costs with the implementation of the plan. Fuel consumption declines 44% by 2038 with the retirements of old Steam gas, heavy fuel oil and coal units. However, fuel consumption is 95% higher compared to the least cost plan under Scenario 4.

**Exhibit 8-32: ESM Plan Fuel Consumption**



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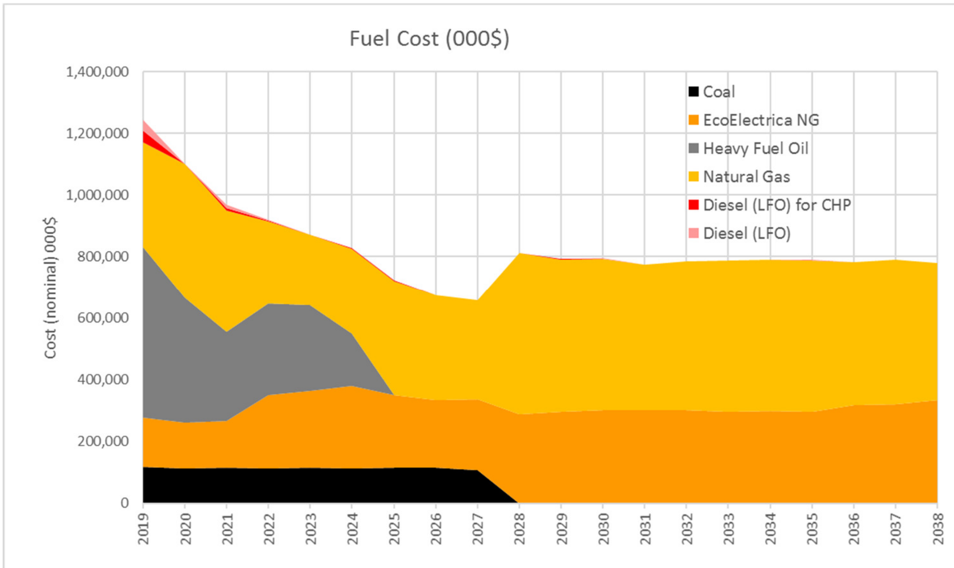
Fuel costs decline in line with the overall fall in fuel consumption falling to a low of $659 million by 2027 (55% below 2019 levels) with all the retirements, including AES. Fuel costs increase in 2028 due to increase generation from EcoEléctrica and San Juan unit 5, after the retirement of AES. Fuel costs stay relative stable after 2028, on average at $787 million in the last ten years of the planning period.

**Exhibit 8-33: ESM Plan Fuel Costs**




## 8.3.5 System Costs

The total cost of supply in real dollars including annualized capital costs, fuel costs, fixed and variable O&M is projected to decline with the implementation of the plan and Base Load forecast from $100.9/MWh in 2019 to $91.0/MWh by 2025 (real $2018), primarily due to the retirement of older generation and the addition of solar and storage. The overall costs increase in 2028 due to rising fuel costs with higher generation from EcoEléctrica and San Juan unit 5, after the retirement of AES (despite the offset from AES costs). Production costs average $95.1/MWh for the first 10 years of the plan, 1.0% lower than the least cost plan under Scenario 4 portfolio (S4S2). In the last ten years of the plan, production costs average $94.7/MWh, slightly lower than the least cost plan under Scenario 4.

The net present value of all operating costs reaches $10.4 billion in 2019-2028 (nominal @ 9% rate). Over the planning period, the NPV is $14.5 billion, only 0.1% lower than the least cost plan under Scenario 4 Portfolio.

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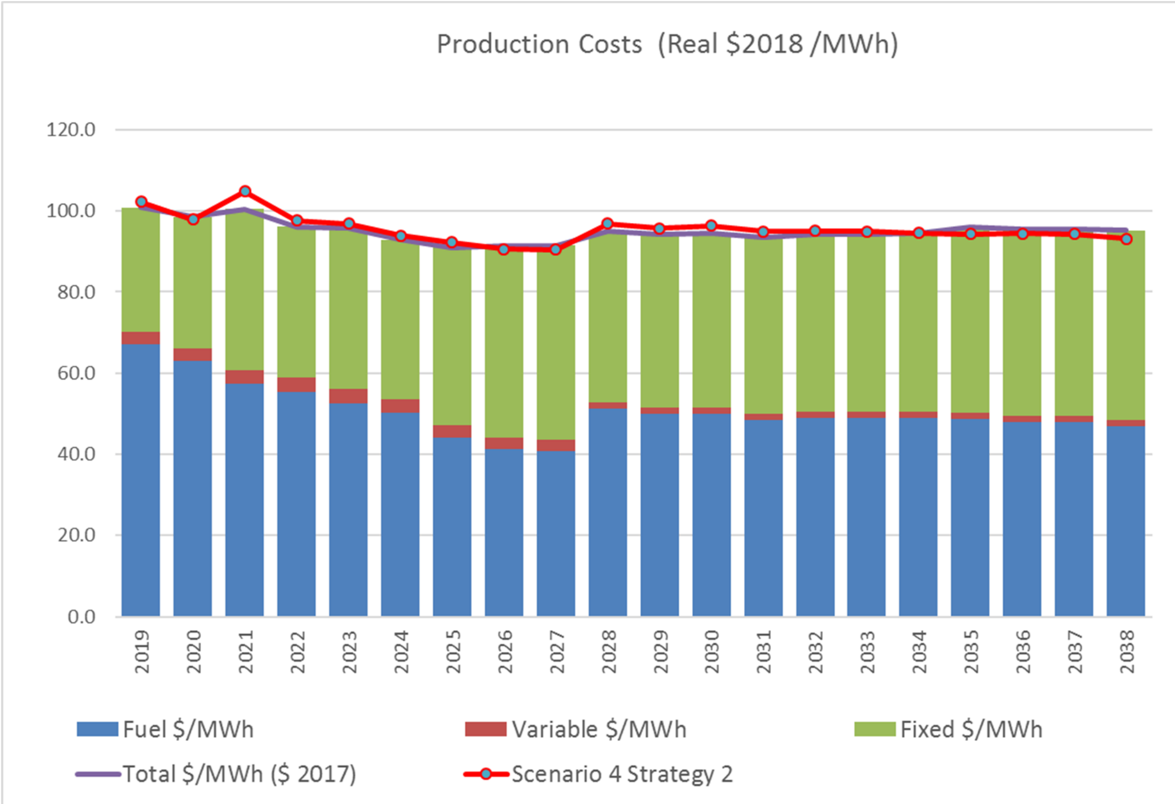
**Exhibit 8-34: Production Costs**




## 8.3.6 Resiliency (Mini Grid Considerations)

In the ESM plan, the critical are fully met with local generation by 2021, however the balance of the load is not fully covered while the plan is being developed in 2019 through 2022. After 2022, it varies depending on the MiniGrid region.

Siemens estimated the costs from unserved energy in the case of a major hurricane impacting the transmission system[59]. It is assumed that a major hurricane occurs every five years impacting major interconnection transmission lines and placing the system into MiniGrids operation for 1 Month, starting in 2022. It is based on a $2000/MWh cost from unserved energy, which considers that the load shedding will be rotated to minimize impact. The $2000 is consistent with the cost of unserved energy for residential customers[60].

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[59] This cost is NOT a forecast of future cost, but rather a high-level determination of how the different portfolios resulting from the combination of scenarios and strategies would perform if every 5 years starting in 2022 a major hurricane impact the island resulting in the operation of the MiniGrids for one month ("Deemed Energy Not Served")

[60] This value is much lower compared to the VOLL determined for PR, in the range of $30,000/MWh

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Exhibit 8-17 summarizes the economic costs by MiniGrid region for the ESM plan. The largest potential costs are for Caguas and Carolina, followed by Arecibo and Cayey. Overall, there is an incremental 319 million in potential costs from unserved energy in the case of a major hurricane impacting the island under this plan. This compares to $228 million for the least cost plan under Scenario 4 due to the fact that this plan has greater amounts of distributed solar resources.  Considering the approximations made to determine these costs of Deemed Energy Not Served, the differences, however, are not considered material as the impact in the NPV of the Total Costs when the effect of the Deemed Energy Not Served is added, is about 82 million (0.6%).

**Exhibit 8-35: Cost of Energy Not Served by MiniGrids**

| MiniGrid | ESM<br>NPV Cost ($000) | Scenario 4<br>NPV Cost ($000) |
|---|---|---|
| San Juan-Bayamon | $ 15,228 | $ 8,874 |
| Ponce | $ - | $ - |
| Carolina | $ 77,508 | $ 40,737 |
| Caguas | $ 103,020 | $ 127,850 |
| Arecibo | $ 63,825 | $ 25,110 |
| Mayaguez-North | $ 12,868 | $ 518 |
| Mayaguez-South | $ 12,837 | $ - |
| Cayey | $ 34,004 | $ 25,196 |
| Total | $ 319,291 | $ 228,285 |

In Caguas, the total thermal energy available (inclusive of solar PV) covers the critical loads but not the priority loads through 2024 under the ESM case. The deployment of 115 MW of peakers (mobile) in 2021 seeks to cover the critical loads in this region under a MiniGrid operation (see Exhibit 8-36). The balance load is met in 2025 and onwards with the addition of a 302 MW F class CCGT in 2025 in Caguas. There is excess generation in this MiniGrid region afterwards.

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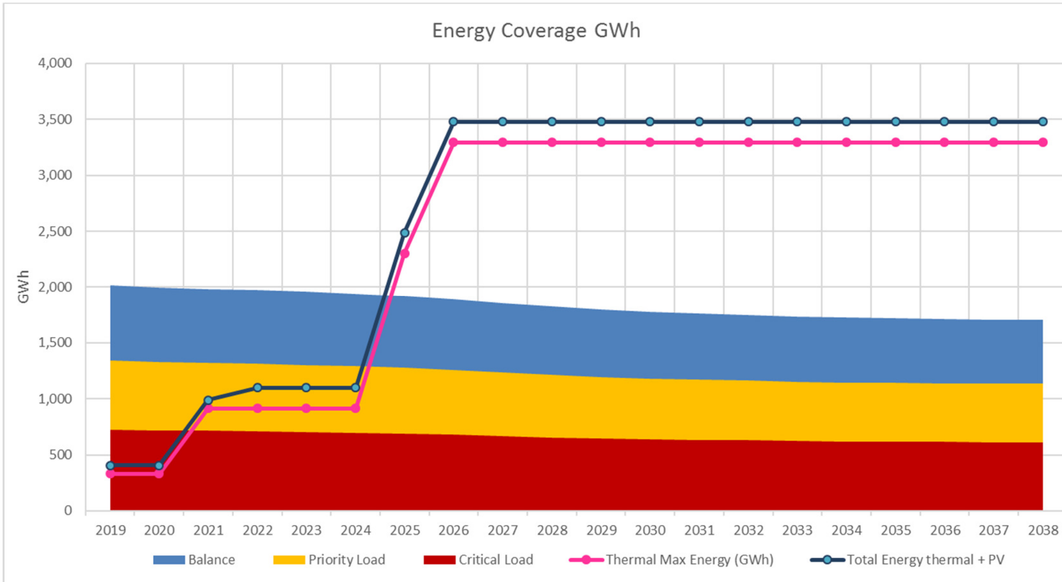
**Exhibit 8-36: Caguas Energy Coverage under a Minigrid Operation**

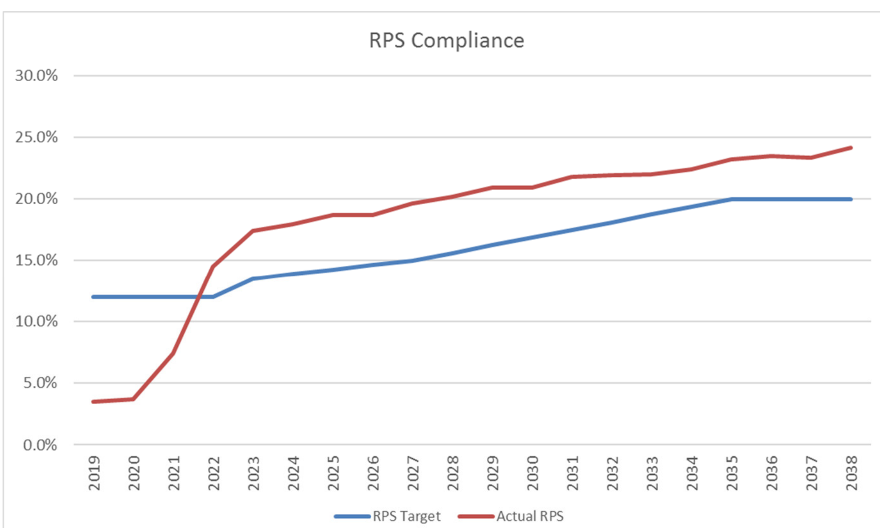



## 8.3.7 RPS and Environmental Compliance

### 8.3.7.1 Renewable Compliance

The renewable portfolio standard targets of 12% by 2022, 15% by 2027 and 20% by 2035 are all met in the ESM case. The plan achieved 24% renewable penetration by 2038. The ESM plan may need to be revisited in the late 2020s if the proposed regulation of 50% renewable generation by 2040 is implemented. In the least cost option under Scenario 4, the 50% target is met prior to 2040.

**Exhibit 8-37: Renewable Portfolio Standards**



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### 8.3.7.2 Environmental Progress

$CO_2$ emissions for PREPA's fleet fall in the first ten years of the forecast driven by the retirement of the older steam fuel oil, diesel and gas units along with increased penetration of solar generation. Emissions fall 39% by 2027 and further by 60% a year later with AES coal retirement in 2028. Emissions continue falling but more gradually after 2028 reaching a 66% reduction by 2038. The emission rate for the fleet falls from 1,334 lbs./MWh in 2019 to 687 lbs./MWh in 2038. Total emissions under the ESM plan are 39% higher compared to the least cost plan under Scenario 4.

The new CCGTs have the lowest emission rates at 820 lbs./MWh. San Juan units converted to natural gas also show low emissions rates at around 850 lbs./MWh. EcoEléctrica is also a low emitter at 877 lbs./MWh. The small 144 MW CCGT unit in the North has higher emissions rate at 918 lbs./MWh, which is shown in the total for CCGTs below prior to 2025 when the new CCGTs are in place. The unit with the highest $CO_2$ emission rates is AES coal at 2,155 lbs./MWh.

**Exhibit 8-38: $CO_2$ Emissions PREPA System**

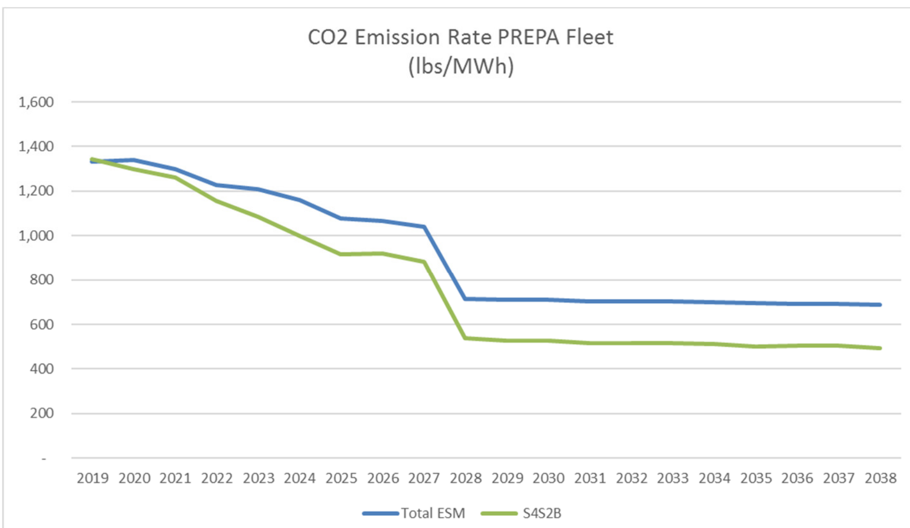


**Exhibit 8-39: $CO_2$ Emissions by Unit Type**

| *lb/MWh* | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|---|
| AES | 2,155 | 2,155 | 2,154 | 2,154 | 2,154 | 2,154 | 2,154 | 2,154 | 2,154 | - |
| EcoElectrica | 877 | 877 | 876 | 878 | 878 | 878 | 878 | 879 | 879 | 877 |
| Costa Sur 5&6 | 1,248 | 1,255 | 1,242 | - | - | - | - | - | - | - |
| Existing Fleet (HFO) | 1,430 | 1,526 | 1,704 | 1,699 | 1,716 | 1,687 | - | - | - | - |
| Diesel CC (LFO) | 159 | 1,335 | 1,335 | 1,335 | 1,335 | 1,335 | 1,335 | 1,335 | 1,335 | 1,335 |
| Existing GTs (LFO) | 1771 | 1464 | 0 | 1813 | 0 | 0 | 0 | 0 | 0 | 0 |
| SJ 5&6 With NG | 866 | 863 | 852 | 852 | 850 | 851 | 849 | 850 | 846 | 849 |
| New CCGT's | 0 | 0 | 0 | 918 | 918 | 918 | 820 | 815 | 814 | 821 |
| New Peaker gas | 0 | 0 | 1211 | 1063 | 1038 | 1041 | 1065 | 1043 | 1047 | 1028 |
| New Peaker diesel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total ESM** | **1,334** | **1,340** | **1,300** | **1,229** | **1,207** | **1,161** | **1,076** | **1,066** | **1,039** | **713** |

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### 8.3.8 Rate Impact

In the sections above, we presented the composition of least cost portfolio formulated under the Energy System Modernization (ESM) Plan Base Case.

In this section and as was done before, we estimate the potential impact of the ESM portfolio on the final rates to customers; and compare the resulting final rates with the possible costs that the customers would incur for self-supply and other customer based alternatives.

The comparison is made considering the "Rate Components" presented earlier (see section **Error! Reference source not found.**)

#### 8.3.8.1 Results of Comparison to Customer Based Alternatives

For rate comparison we considered, as before and are described in greater detail in Appendix 4 Demand Side Resources.

In this section we describe the results of the analysis we performed comparing the final ESM rates to unit costs for customer based alternatives.

The ESM generation portfolio costs are slightly lower compared to the S4S2 portfolio; however, the cost reduction is not significant enough to change the comparison observations and inferences for the S4S2 rate impact analysis. The comparison analysis results are illustrated in Exhibit 8-40, and are summarized below:

- The unit costs for all the customer alternatives considered are lower than the final all-in ESM generation portfolio rate.
- The levelized cost of customer alternatives (especially Solar PV and Grid Defection) is higher than the cost of the generation delivered to the customer and that includes the effect of losses until 2028 (when AES Coal retires). However, this cost is significantly lower than the total rate even before the non-bypassable component and confirms the assumption in the DG forecast that the continuance of 'net-metering' rates will occur, and the customer side roof top PV adoptions will continue to be in line with the high adoption rates observed to date.
- These results also indicate that, given PREPA's non-bypassable rate component forecasted, coupled with the expected reduction in renewable generation costs, the customers may be motivated to self-supply if they are able to raise the capital investment required for installing the self-supply option or if a developer installs the equipment and recovers the investment through leases or other financing options.
- It is also interesting to note that when the Non-Bypassable charge is added to the case where the customer only has PV and uses PREPA as a bank (net-metering) the costs are very similar to the complete self-supply option. However, in this case there is an added advantage of no need for the initial capital outlay. So, provided that the PREPA service meets the reliability expectations of the customer, it can be reasonably concluded that the customer will continue to be connected to the PREPA grid.

We analyzed another case where we reduced the non-technical losses to typical values observed in the US (0.5% or less). Note that the distribution technical losses are within the

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expected values of PREPA's peers and account for the reduction in losses due to the increased penetration of distributed generation. Keeping all else the same, the resulting final rate for the ESM generation portfolio, also reduces, but not to the extent that our above observations and inferences change. This updated comparison chart is given in the exhibit below.

**Exhibit 8-40: Final ESM Generation Portfolio Rates Compared to Unit Costs of Customer Alternatives**

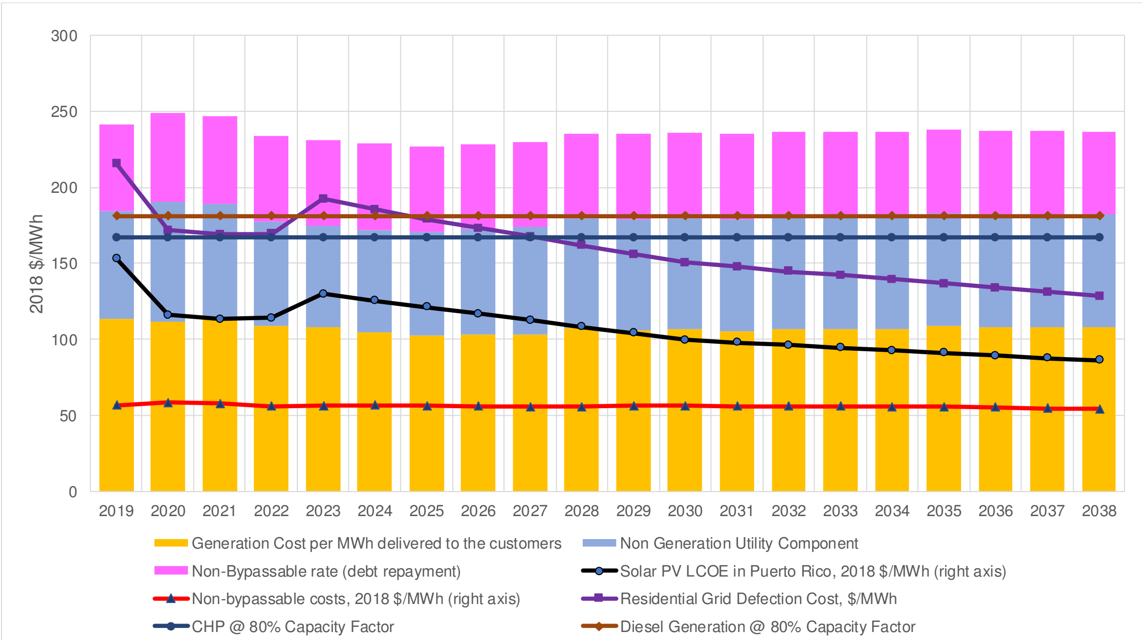

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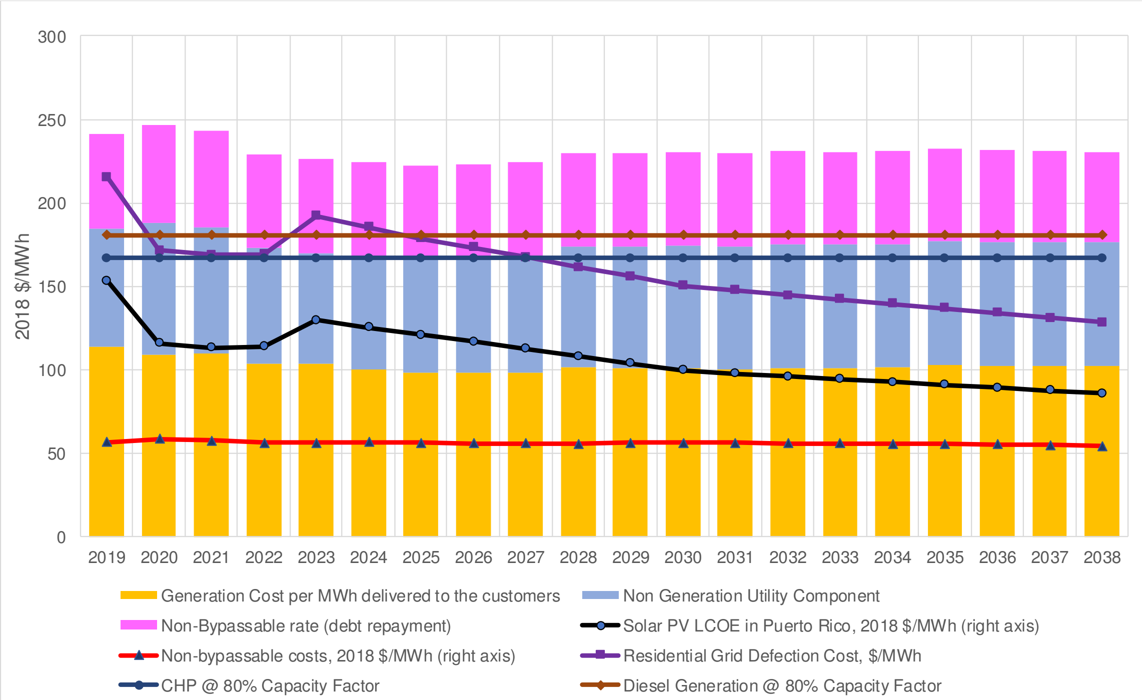
**Exhibit 8-41: Final ESM Generation Portfolio Rates Assuming Reduced Losses**




## 8.3.9 Nodal Analysis of the ESM

As was the case of Scenario 4, we analyzed the ESM using a nodal simulation. The objective again was to identify the effects of transmission on the key metrics of technical losses, production costs, renewable curtailment and energy not served.

The results of the nodal runs show the production costs of the nodal runs match very closely with those of the zonal runs used for the LTCE assessment for the entire period and that there is no curtailment (see Exhibit 8-42).

The losses in each of the nodal cases was less than that of the zonal runs used, due to the more accurate modeling of the transmission system. On average the reduction in losses is approximately 1.0%. The difference in losses noted from 2019 – 2028 is an average of 1.5% lower. From 2029 – 2038 the losses difference is an average of 0.7% lower; see Exhibit 8-43.

There was no energy not served in the nodal runs, which is in line with the results of the zonal runs.

In summary the minimal impact of transmission was expected due to the greater distribution of generation resources and reduced load.

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**Exhibit 8-42: Production Costs Nodal vs. Zonal and Renewable Curtailment**

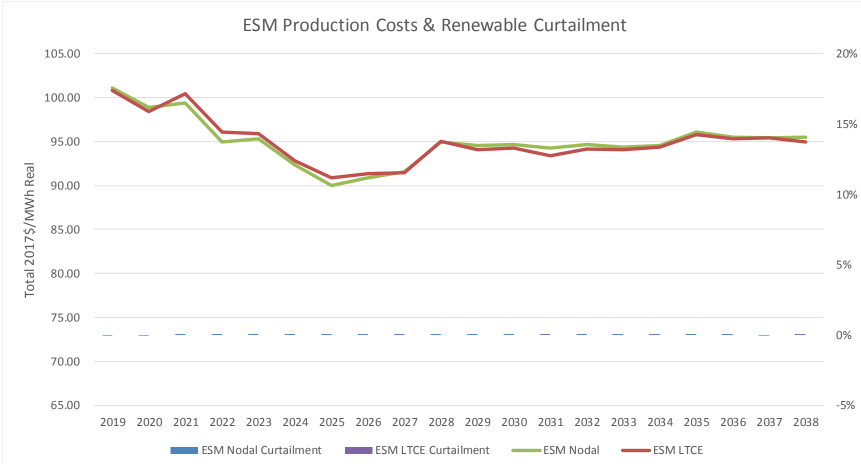


**Exhibit 8-43: Transmission Losses Differences**

| Loss Difference | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LTCE Losses | 3.7% | 3.2% | 2.6% | 2.6% | 2.0% | 2.1% | 2.0% | 2.0% | 1.9% | 1.1% | 1.0% | 1.0% | 0.9% | 0.9% | 0.9% | 0.9% | 0.8% | 0.8% | 0.8% | 0.7% |
| NODAL Losses | 1.1% | 1.0% | 0.8% | 0.7% | 0.6% | 0.5% | 0.6% | 0.6% | 0.5% | 0.6% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% | 0.5% |
| **DIFFERENCE** | **2.6%** | **2.2%** | **1.8%** | **1.8%** | **1.4%** | **1.6%** | **1.4%** | **1.5%** | **1.4%** | **0.6%** | **0.5%** | **0.5%** | **0.4%** | **0.4%** | **0.4%** | **0.3%** | **0.3%** | **0.3%** | **0.3%** | **0.2%** |

## 8.4 Scenario 1 Results

Scenario 1 is a portfolio in which there is no new LNG terminals can be developed in the island. Only existing gas at the Cost Sur LNG terminal is available. The scenario also considers base case assumptions for solar and storage costs and availability.

Scenario 1 was simulated under the base high and low load forecast and under three strategies, strategy 2 (decentralized 80% of demand met by local resources base case), strategy 3 (50% of demand met with local generation) and strategy 1 (centralized system).

Three sensitivities were run also with this scenario; Sensitivity 1; low cost of renewable, Sensitivity 2 low levels of energy efficiency (1% reduction for 10 year) and Sensitivity 3 (Economic retirement of AES)

In general Scenario 1 result in a plan that has higher production costs compared to other plans including Scenario 4 and the ESM. Most of the increase in costs comes from a much larger development of solar and storage required to meet the load. Scenario 1 achieves much higher levels of renewable penetration in the order of 82% that requires intensive use of the storage and could be challenging to operate (3846 MW on a system that could have peak load little over 2,000 MW).

Resiliency at the MiniGrid level is comparable to the Scenario 4.

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Exhibit 8-44 below provides a summary of the investments results for Scenario 1 and the key cost metrics in comparison with the S4S2B and the ESM case. Sensitivity 3 is being revised as of this writing as the AES plant was retired and this is inconsistent.

**Exhibit 8-44. Scenario 1 Summary of results**

| | Large & Medium CCGTs | | | | | | | | Renewable and Storage | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Case ID** | F - Class Palo Seco 2025 | F - Class Costa Sur 2025 | F-Class Mayaguez 2028 | F-Class Yabucoa 2025 | Small CCGT (LPG/NG) North | F - Class San Juan 2029 | Medium CCGT Yabucoa 2024 | Peakers (small CC) 2019-2022 | New Solar 2019 - 2022 | BESS 2019 - 2022 | New Solar 2023 - 2028 | BESS 2023 - 2028 | New Solar Total | BESS Total |
| S1S2B | **X** | ✔ (2025, 2028) | **X** | **X** | X | X | X | 396 | **1200** | 1200 | 2520 | 380 | 3720 | 2140 |
| S1S2H | **X** | ✔ (2025 x 2, 2033) | **X** | **X** | X | X | ✔ Bayamon 2027 | 472 | **1200** | 1240 | 3060 | 120 | 4320 | 1880 |
| S1S2L | **X** | ✔ (2025, 2028) | **X** | **X** | X | X | X | 303 | **1200** | 1160 | 2100 | 180 | 3300 | 1800 |
| S1S3B | ✔ | ✔ (2025, 2028) | **X** | **X** | X | X | X | 343 | **1200** | 1120 | 2520 | 160 | 3720 | 1640 |
| S1S3H | ✔ (141 MW) | ✔ (2025, 2028) | **X** | **X** | X | X | ✔ Bayamon 2025 | 476 | **1200** | 940 | 3060 | 120 | 4260 | 2500 |
| S1S3L | **X** | ✔ (2025, 2028) | **X** | **X** | X | X | X | 303 | **1200** | 1120 | 2040 | 20 | 3240 | 1900 |
| S1S2S1B | ✔ (141 MW) | ✔ (2025, 2028) | **X** | **X** | X | X | X | 345 | **1200** | 1120 | 2640 | 500 | 3840 | 2700 |
| S1S2S2B | **X** | ✔ (2025 x 2, 2028) | **X** | **X** | X | X | X | 444 | **1200** | 1140 | 2820 | 80 | 4020 | 1800 |
| S1S2S3B | ✔ (141 MW) | ✔ (2025 x 2, 2036) | **X** | **X** | X | X | X | 472 | **1200** | 1240 | 3060 | 120 | 4320 | 1880 |
| S1S1B | **X** | ✔ (2025, 2028) | **X** | **X** | X | X | X | 297 | **1200** | 1160 | 2520 | 0 | 3720 | 2220 |
| S4S2B | ✔ | ✔ | ✔ | X | X | X | X | 388 | **1200** | 900 | 1020 | 40 | 2220 | 1080 |
| ESM Plan | ✔ | **Eco Instead** | X | ✔ | ✔ | X | X | 418 | **720** | 440 | 180 | 140 | 900 | 800 |
| **ESM w/o LPG** | | [redacted] | | | | | | | | | | | | |

| **Case ID** | **NPV @ 9% 2019-2038 $000** | **Average 2019-2028 2018$/MWh** | **RPS 2038** |
|---|---|---|---|
| S1S2B | 15,458,037 | 101.1 | 81% |
| S1S2H | 17,177,891 | 101.7 | 89% |
| S1S2L | 14,120,288 | 100 | 71% |
| S1S3B | 15,401,758 | 101 | 76% |
| S1S3H | 17,109,321 | 101 | 93% |
| S1S3L | 14,052,124 | 99 | 71% |
| S1S2S1B | 14,852,306 | 97 | 84% |
| S1S2S2B | 16,640,966 | 100 | 84% |
| S1S2S3B | 17,147,407 | 101 | 89% |
| S1S1B | 15,395,763 | 101 | 81% |
| **S4S2B** | 14,520,725 | 96.4 | 51% |
| **ESM Plan** | 14,511,798 | 95.4 | 24% |

## 8.4.1 Capacity Additions and Retirements for Scenario 1

The economic simulation of Scenario 1 Base load forecast results in 3,720 MW of utility scale PV additions over the study period with 1200 MW added in 2019-2022, maximizing solar PV capacity additions in the short to medium term, consistent with the least cost plans, e.g. Scenario 4, ESM and Scenario 3. All solar PV additions happen in the first 10 years of the plan. Solar additions are 600 MW under the high load case but 420 MW lower under the low load case. Under strategy 3, solar additions are similar (see Exhibit 8-44).

To support the operation of that much solar, a total of 2,744 MW of battery energy storage is added over the study period, with about half of the total installed in 2019-2022. A second batch of storage installations happen after the retirement of the AES in 2028. Storage additions are lower under the high load case (due to more CCGT additions) and the low load case (less need).

Two large CCGTs are installed, both in Costa Sur, one in 2025 and another in 2028, after the retirement of AES. These two plants utilize the gas available in the South after the retirement of the existing Costa Sur units, one retired in 2022 and the other in 2030. Under the high load case, an additional large CCGT is installed in Costa Sur in 2033 and a medium CCGT in Bayamon in 2027. Under the low load case, CCGT additions are the

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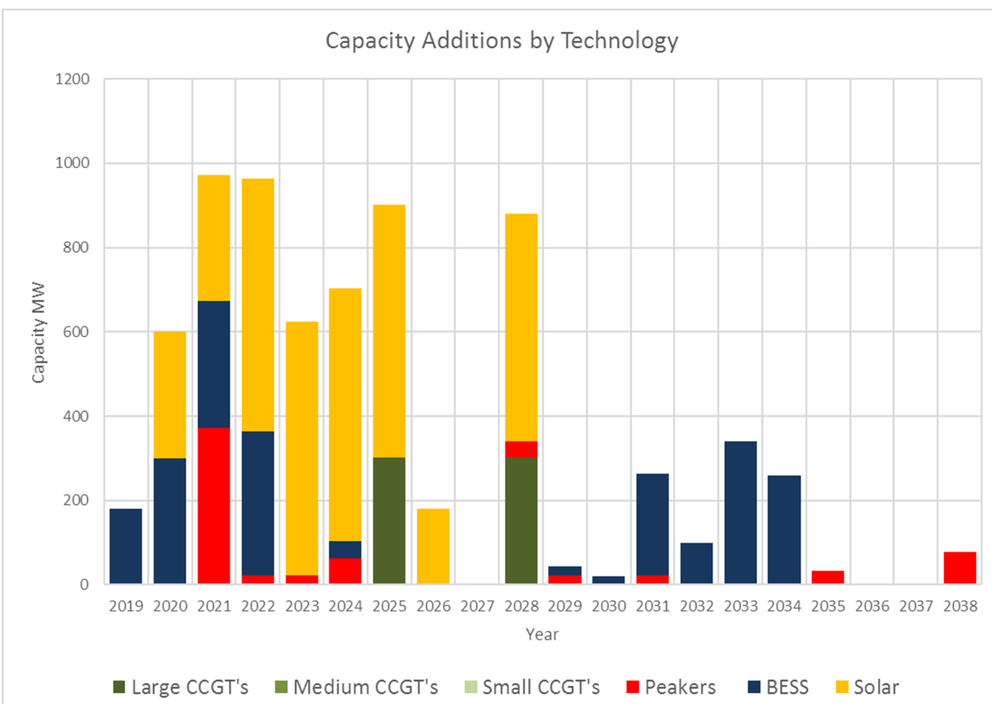
same as the base load case. There is not much difference either under Strategy 3, except for a small CCGT at Palo Seco in 2025 and a medium CCGT in Bayamon, both under the high load case (see Exhibit 8-44).

The need for peaking capacity is somewhat larger compared to scenario 4 over the planning period due to the higher renewable penetration, with an incremental 242 MW more of peakers (over the period 2019 -2022 values are similar). San Juan 5 & 6 are not converted to gas in this scenario assumes no new gas terminals in the island. San Juan 6 is retired in 2023 and San Juan 5, ten years later in 2033, under the base load case.

Under strategy 1 (a centralized plan), the expansion plan is very similar, both in terms of solar PV and storage additions, as well as CCGT capacity. Overall system costs are slightly lower but the risk and costs from unserved energy due to a disruptive hurricane are larger (see Exhibit 8-44).

The Plan is MATS compliant after 2024 and achieve 81% RPS compliance by 2038 (much higher than Scenario 4 or the ESM, with most of the new capacity coming from solar and storage.

**Exhibit 8-45: Scenario 1 Base Load Capacity Additions**



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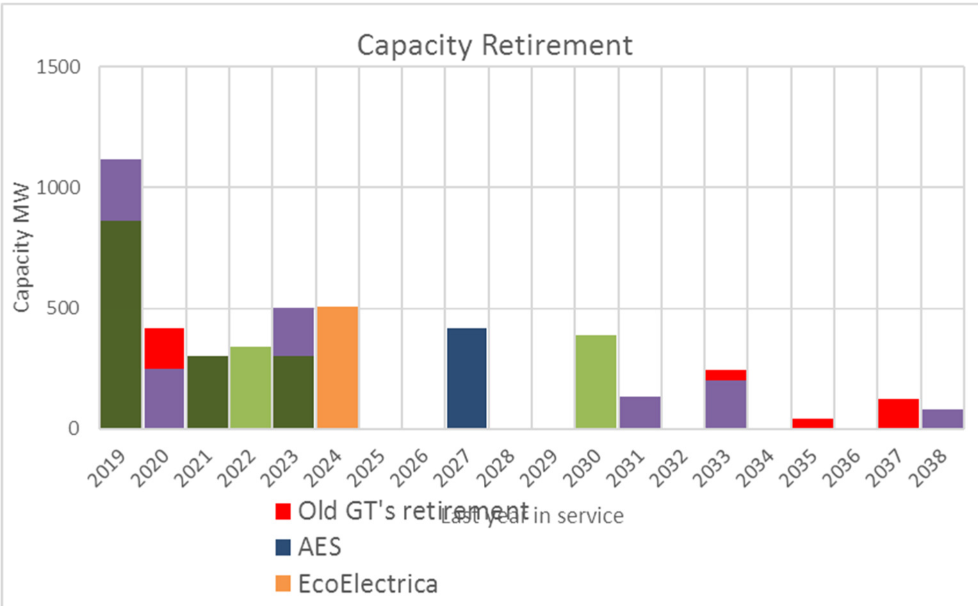
| Capcacity by technology MW | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Large CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 302 | 0 | 0 | 302 | 0 |
| Medium CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Peakers | 0 | 0 | 373 | 23 | 23 | 62 | 0 | 0 | 0 | 39 | 23 |
| BESS | 180 | 300 | 300 | 340 | 0 | 40 | 0 | 0 | 0 | 0 | 20 |
| **Total Distchable Additions** | **180** | **300** | **673** | **363** | **23** | **102** | **302** | **0** | **0** | **341** | **43** |
| Solar | 0 | 300 | 300 | 600 | 600 | 600 | 600 | 180 | 0 | 540 | 0 |
| **Total Additions** | **180** | **600** | **973** | **963** | **623** | **702** | **902** | **180** | **0** | **881** | **43** |

## Exhibit 8-46: Scenario 1 Base Load Capacity Retirements




| Capcacity by technology MW | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PREPA Steam (HFO) | 862 | 0 | 300 | 0 | 301 | 0 | 0 | 0 | 0 | 0 | 0 |
| PREPA MATS Affected units remaining | | | | | | 0 | 0 | 0 | 0 | 0 | 0 |
| PREPA Costa Sur (Gas) | 0 | 0 | 0 | 339 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PREPA Diesel CC & large GTs | 257 | 249 | 0 | 0 | 200 | 0 | 0 | 0 | 0 | 0 | 0 |
| PREPA CC-converted (Gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EcoElectrica | 0 | 0 | 0 | 0 | 0 | 507 | 0 | 0 | 0 | 0 | 0 |
| AES | | | | | | | | | 416 | 0 | 0 |
| **Total Dependable Gen Retirement** | **1119** | **249** | **300** | **339** | **501** | **507** | **0** | **0** | **416** | **0** | **0** |

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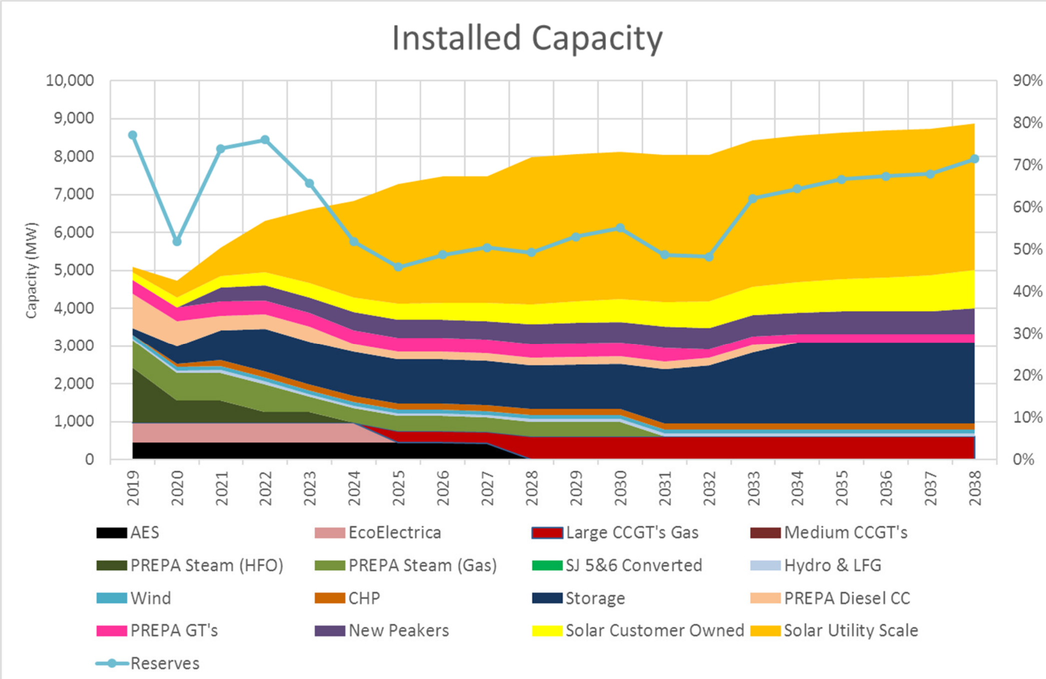
**Exhibit 8-47: Scenario 1, Future Capacity Mix**




As PREPA's units and the thermal PPOA's are phased out the operating reserves decline from 77% in 2019 to a low of 46% by 2025. The Planning Reserve Margin of 30% appears not to have been binding constraint on the LTCE plan formulation in this scenario and observes a minimum of 41% in 2025.

### 8.4.1.1 Sensitivity Considerations

The Siemens team evaluated sensitivities under scenario 1 to isolate the impacts of certain important variables while holding other assumptions constant. For the 2018 IRP, three sensitivities were modeled: low costs of solar and storage, low energy efficiency and economic retirements of AES.

Under low costs of renewables, there is a modest increase of 120 MW in solar additions and 560 MW from storage. This illustrates that even with lower costs of solar; an optimal amount of solar is installed under the base load case. In the case with low EE penetration, there is 300 MW of additional solar but 300 MW less storage.

## 8.4.2 Fuel Diversity

In line with the change in the energy supply matrix, the system moves away from heavy fuel oil and coal to natural gas and diesel along with a sharp drop in overall fuel consumption and associated costs with the implementation of the plan. By 2038, 80% of the generation is coming from renewables.

Fuel consumption declines with the retirement of old Steam gas and heavy fuel oil units and peakers along with EcoEléctrica's retirement by the end of 2024. Overall fuel consumption continues to fall through 2038 despite the new CCGTs install in Costa Sur

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in 2025-2028. Total fuel consumption drops to 20% by 2038 with most of the fuel used coming from natural gas.

Fuel costs decline in line with the overall fall in fuel consumption falling to a low of $484 million by 2038 (60% below 2019 levels) with all the retirements, including AES. In this scenario, 16% of the total fuel costs still come from diesel generation by 2038.

**Exhibit 8-48: Scenario 1 Fuel Consumption**

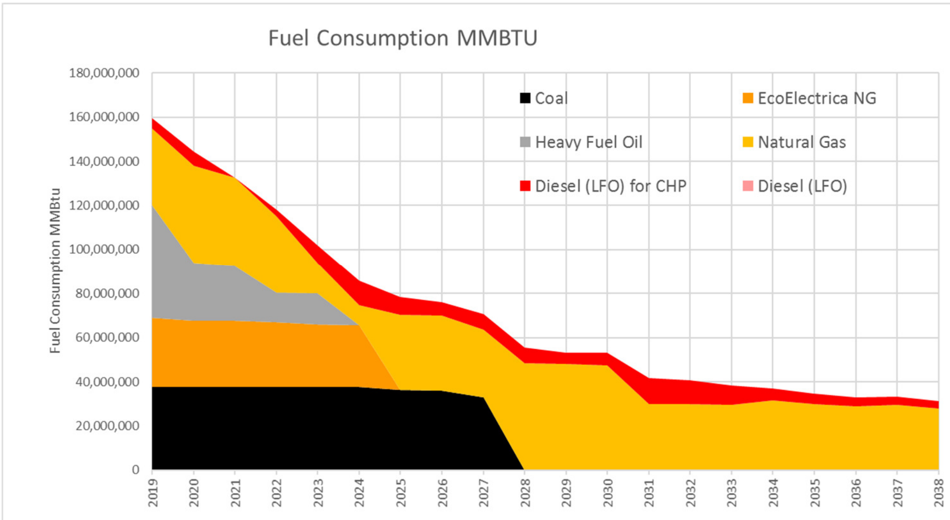
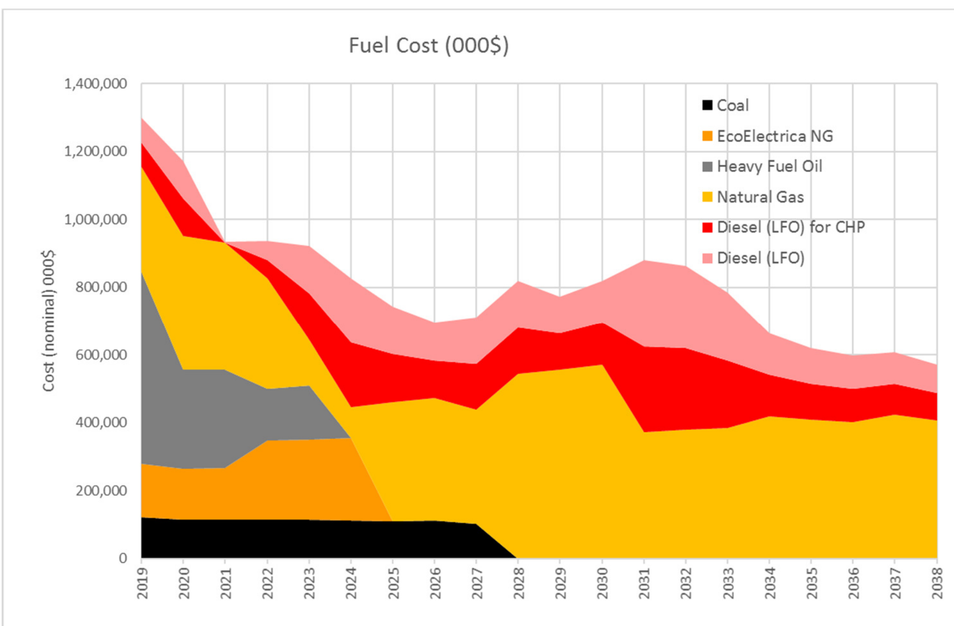



**Exhibit 8-49: Scenario 1 Fuel Costs**




### 8.4.3 System Costs

The total cost of supply in real dollars including annualized capital costs, fuel costs, fixed and variable O&M is projected to decline with the implementation of the plan from

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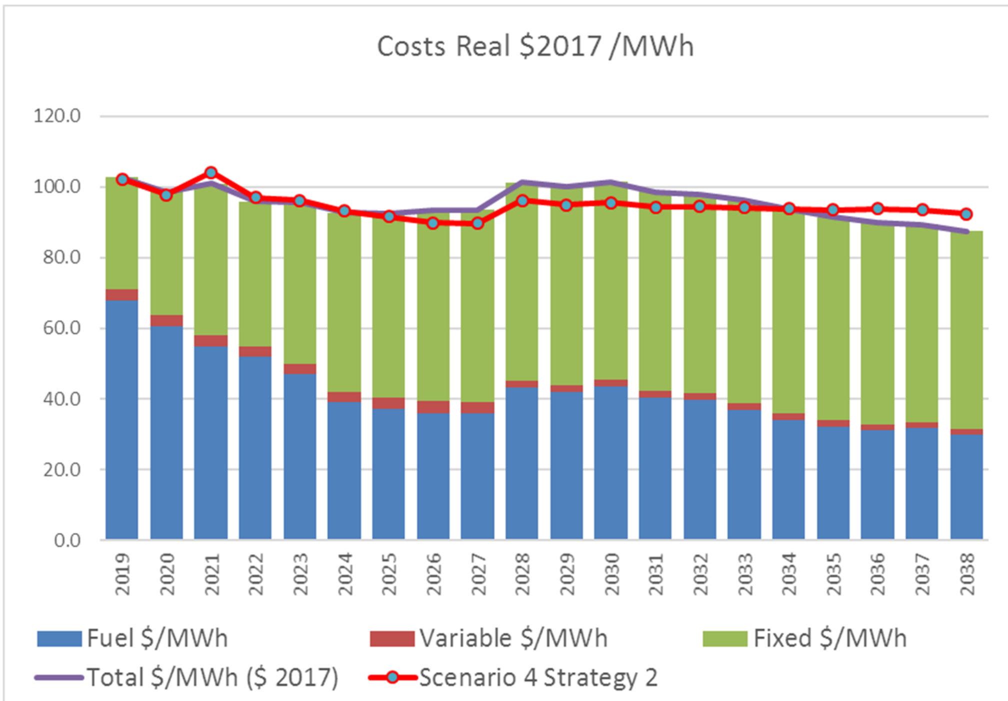
$ 103.4/MWh in 2019 to $99.5/MWh by 2026 (real $2018), prior to AES Coal retirement, with the addition of solar and storage and the retirement of older generation. The costs increased in 2028 to $108.6/MWh with the addition of the new CCGT. The, system costs decline with falling fuel costs to reach $100.0/MWh by 2038.

The net present value of all operating costs reaches $10.9 billion for 2019-2028 (nominal @ 9% rate). Over the study period, the NPV is $15.4 billion. This plan is $917 million more expansive compared to the reference Scenario 4, primarily due to higher capital investment costs with a lot more renewables and fuel costs with more diesel in the mix.

**Exhibit 8-50: Scenario 1 Production Costs**




## 8.4.4 RPS Compliance

The renewable portfolio standard targets of 12% by 2022, 15% by 2027 and 20% by 2035 are all met and exceeded in the Scenario 5 base case under all strategies. The plan achieved 81% renewable penetration by 2038, exceeding the proposed goal of 50% renewable generation by 2040. This plan achieves much higher compliance compared to Scenario 4, that is also in compliance even with the proposed 50% compliance.

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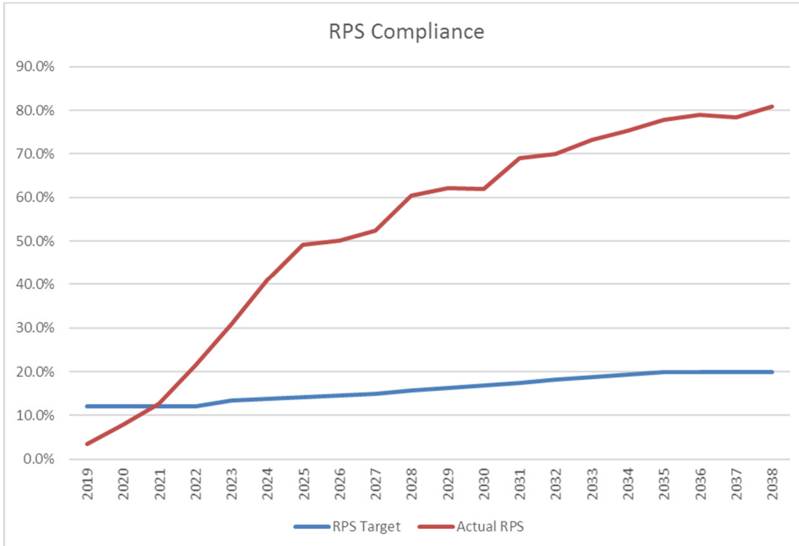
**Exhibit 8-51: Scenario 1 RPS Compliance**




## 8.4.5 Rate Impact

In the sections above, we presented the composition of least cost portfolio formulated under the Scenario 1, Strategy 2 (S1S2) Base Case.

In this section and as was done before, we estimate the potential impact of the ESM portfolio on the final rates to customers; and compare the resulting final rates with the possible costs that the customers would incur for self-supply and other customer based alternatives.

The comparison is made considering the “Rate Components” presented earlier (see section **Error! Reference source not found.**)

## 8.4.6 Results of Comparison to Customer Based Alternatives

In this section we describe the results of the analysis we performed comparing the final S1S2 rates to unit costs for customer based alternatives.

The S1S2 generation portfolio costs are higher than those of the S4S2 costs, but the comparison observations and inferences remain largely the same as those for the S4S2 rate impact analysis. The comparison analysis results are illustrated in Exhibit 8-52, and are summarized below:

- The unit costs for all the customer alternatives considered are lower than the final all-in S1S2 generation portfolio rate.
- The levelized cost of customer alternatives (especially Solar PV and Grid Defection) is higher than the cost of the generation delivered to the customer and that includes the effect of losses until 2028 (when AES Coal retires). However, this cost is significantly lower than the total rate.
- These results also indicate that, given PREPA’s non-bypassable rate component forecasted, coupled with the expected reduction in renewable generation costs,

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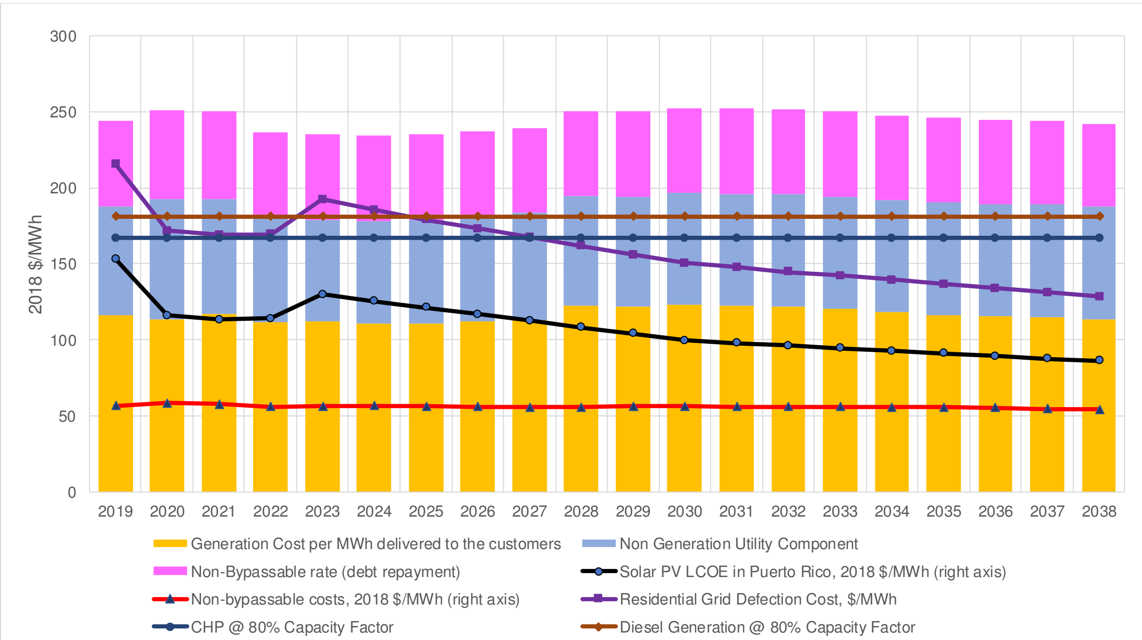
the customers may be motivated to self-supply if they are able to raise the capital investment required for installing the self-supply option or if a developer installs the equipment and recovers the investment through leases or other financing options.

**Exhibit 8-52: Final S1S2 Generation Portfolio Rates Compared to Unit Costs of Customer Alternatives**




As before, we analyzed another case where we reduced the non-technical losses to typical values observed in the US (0.5% or less) and the resulting final rate for the S1S2 generation portfolio, also reduces, but not to the extent that our above observations and inferences change. This updated comparison chart is given in the exhibit below.

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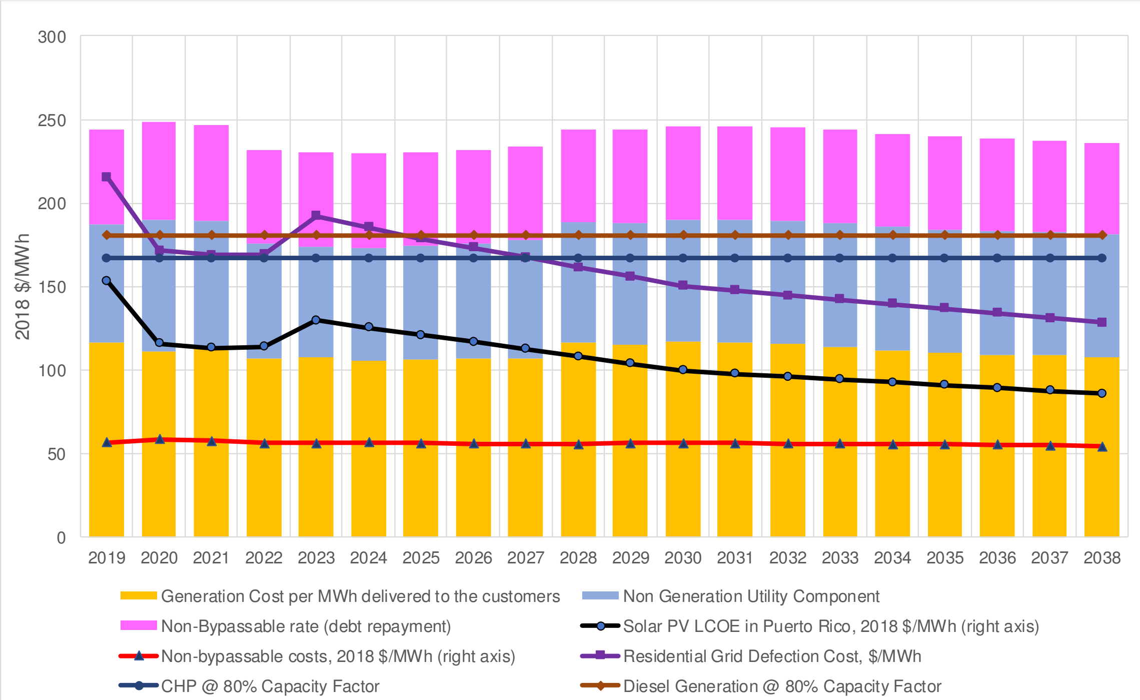
**Exhibit 8-53: Final S1S2 Generation Portfolio Rates Assuming Reduced Losses**




## 8.4.7 Nodal Analysis of the S1S2B

The nodal assessment highlighted the difficulty to manage the storage to integrate the large amounts of renewable in the case and potentially lead to large curtailment. The nodal runs used a different strategy to dispatch the storage that resulted in high levels of curtailment and increase in costs. We are not of the opinion that the results below are realistic and to be expected, but rather highlight this difficulty and risk. We are reviewing the dispatch logic and as a follow up of this report, we will provide an update. We expect that the curtailment will be in line with the long term capacity expansion plan and/or more storage will be required for the integration. The technical loss reduction was also noted with values similar as before.

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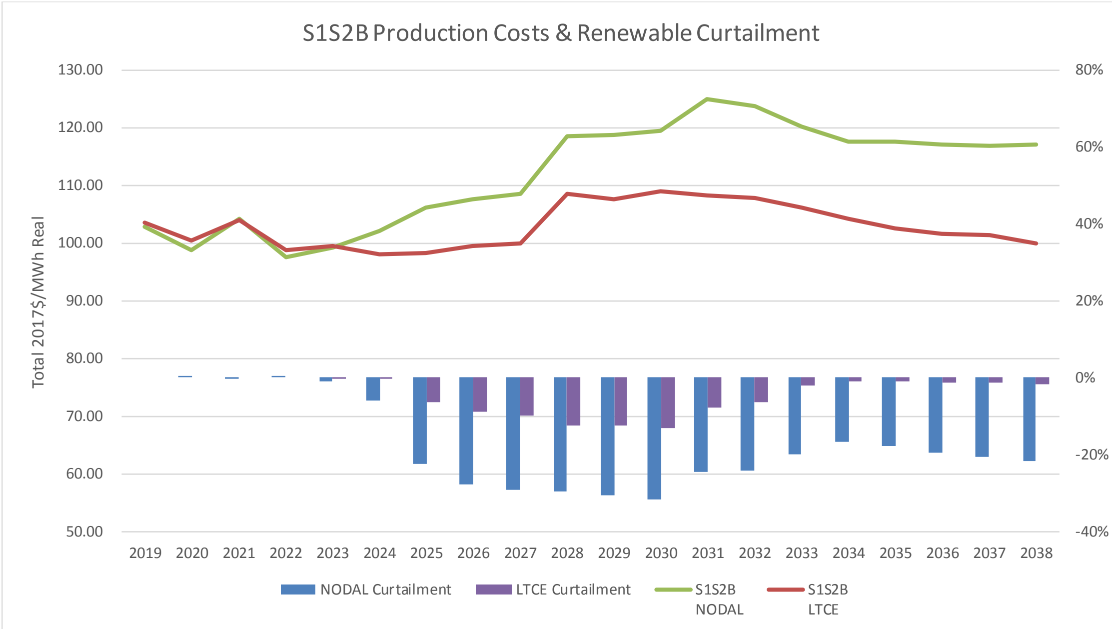
**Exhibit 8-54: Production Costs Nodal vs. Zonal and Renewable Curtailment**




## 8.5 Scenario 3 Base Case Results

### 8.5.1 Capacity Additions and Retirements

The generation portfolio identified as Scenario 3 Strategy 2 (S3S2) result in a plan that has lower production costs as compared to the Scenario 4 and the ESM. The portfolio has a good balance of resources for a distributed system on a minigrid level capable of supplying the critical and priority loads for the customer in an event of a major disruptive hurricane.

However, the implementation of 4,020 MW of solar in a 2,200 MW peak demand system would be a significant challenge and could be difficult to achieve for practical purposes. The operation of the system would be a challenge with such a high level of solar penetration and its natural intermittency, increasing the risk of curtailment (that would negate some of the perceived economies) and puts strain and reliance on the Storage.

The scenario assumes lower capital investment costs for solar and storage (NREL Low Case) coupled with high availability of renewables (early ramp up). It also assumes gas available at Yabucoa (east) and Mayagüez (west) through ship-based LNG, in addition to gas to the north supplied through land-based LNG at San Juan. The land-based LNG at San Juan is assumed to acquire the required permitting approval.

The economic simulation of the Scenario 3 case results in 4,020 MW of utility scale PV additions over the study period with 1,500 MW added as soon as 2022 (the maximum available, consistent with the PREB orders). Solar installations are 1,800 MW larger compared to Scenario 4. The amount of solar capacity additions varies depending on

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the load forecast with 4,560 MW under a high load case and 3,480 MW under a low load case. If the scenario is simulated under Strategy 3, there is a slight reduction in solar builds with 3,960 MW under a base load case due to lower capacity requirements at the MiniGrid level (see Exhibit: 8-55).

In this scenario, 2,380 MW of battery energy storage is built over the study period, mostly in 2019-2023 hitting the annual installation limits allowed for most years (2019 to 2022). A second batch of storage is installed after AES and San Juan 5 retirement.

Only two large CCGTs are installed with 302 MW each in Costa Sur and Palo Seco (Bayamon), under the base load case. Under the low load case, the Palo Seco CCGT is added by 2027. In the high load case, there is no change under Strategy 2 but the Palo Seco CCGT unit is delayed for Strategy 3 until 2027.

Due to the higher renewable penetration, there is a larger need for peaking capacity to balance the system with 517 MW, 135 MW more compared to scenario 4. San Juan units 5 & 6 converted to natural gas in 2019, with San Juan 5 retired economically in 2034 and San Juan 6 in 2032. EcoEléctrica is retired in 2024, in line with Scenario 4.

The Plan is MATS compliant after 2024 and achieves 87% RPS compliance by 2038 (much higher than the scenario 4 portfolio) as a result of lower costs of renewables and higher availability.

**Exhibit: 8-55: Scenario 3 Results.**

| | Large & Medium CCGTs | | | | | | | | Renewable and Storage | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Case ID** | F - Class Palo Seco 2025 | F - Class Costa Sur 2025 | F-Class Mayaguez 2028 | F-Class Yabucoa 2025 | Small CCGT (LPG/NG) North | F - Class San Juan 2029 | Medium CCGT Yabucoa 2024 | Peakers (small CC) 2019-2022 | New Solar 2019 - 2022 | BESS 2019 - 2022 | New Solar 2023 - 2028 | BESS 2023 - 2028 | New Solar Total | BESS Total |
| S3S2B | ✔ | ✔ | X | X | X | X | ✔ | 303 | **1500** | 980 | 2520 | 200 | 4020 | 2380 |
| S3S2H | ✔ | ✔ | X | X | X | X | X | 303 | **1500** | 1180 | 4560 | 200 | 4560 | 3260 |
| S3S2L | ✔ 2027 | ✔ | X | X | X | X | X | 303 | **1500** | 940 | 1980 | 240 | 3480 | 1980 |
| S3S3B | ✔ | ✔ | X | X | X | X | X | 303 | **1500** | 1020 | 2460 | 260 | 2760 | 3960 |
| S3S3H | ✔ 2027 | ✔ | X | X | ✔ (76MW) | X | ✔ | 303 | **1500** | 1100 | 2880 | 100 | 4560 | 2220 |
| S3S3L | ✔ 2027 | ✔ | X | X | X | X | X | 303 | **1500** | 960 | 1860 | 260 | 3420 | 2440 |
| S4S1B | ✔ | ✔ | ✔ | X | X | X | X | 324 | **1200** | 900 | 1140 | 0 | 2340 | 1460 |
| ESM Plan | ✔ | **Eco Instead** | X | ✔ | ✔ | X | X | 418 | **720** | 440 | 180 | 140 | 900 | 800 |

| **Case ID** | **NPV @ 9% 2019-2038 $000** | **Average 2019-2028 2018$/MWh** | **RPS 2038** |
|---|---|---|---|
| S3S2B | 14,167,571 | 93 | 87% |
| S3S2H | 15,414,838 | 94 | 99% |
| S3S2L | 12,910,613 | 92.3 | 76% |
| S3S3B | 14,074,355 | 93.3 | 87% |
| S3S3H | 15,394,694 | 93.4 | 96% |
| S3S3L | 12,876,825 | 91.8 | 96% |
| S4S1B | 14,677,616 | 97.3 | 51% |
| ESM Plan | 14,511,798 | 95.4 | 24% |

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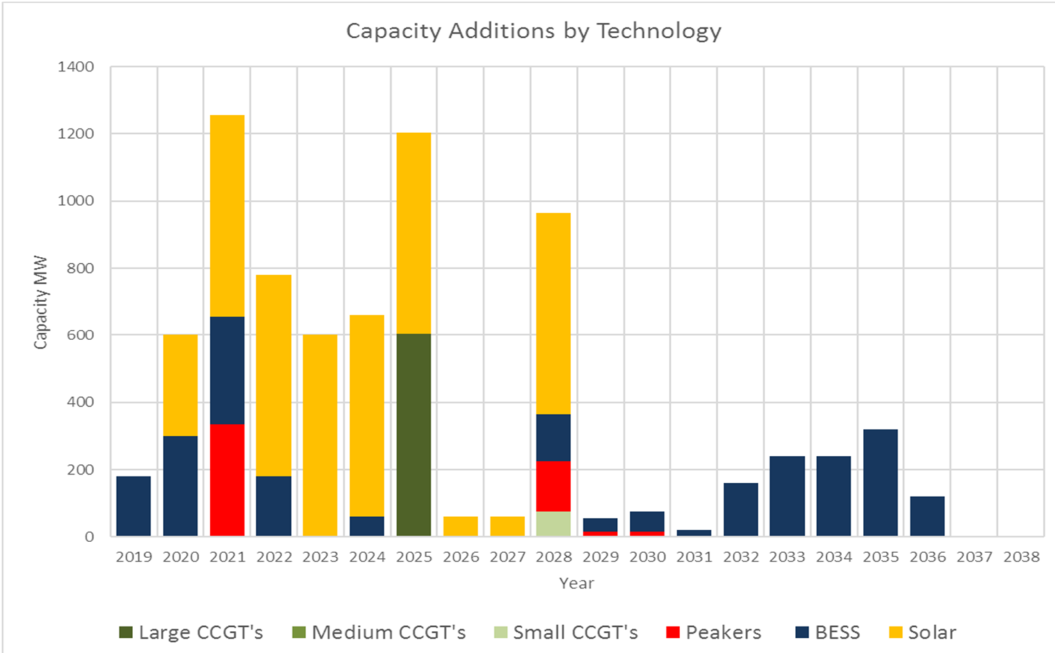
## Exhibit 8-56: Scenario 3 Base Load Forecast Capacity Additions




| Capacity by Technology MW | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Large CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 604 | 0 | 0 | 0 | 0 |
| Medium CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 76 | 0 |
| Peakers | 0 | 0 | 335 | 0 | 0 | 0 | 0 | 0 | 0 | 149 | 16 |
| BESS | 180 | 300 | 320 | 180 | 0 | 60 | 0 | 0 | 0 | 140 | 40 |
| **Total Distchable Additions** | **180** | **300** | **655** | **180** | **0** | **60** | **604** | **0** | **0** | **365** | **56** |
| Solar | 0 | 300 | 600 | 600 | 600 | 600 | 600 | 60 | 60 | 600 | 0 |
| **Total Additions** | **180** | **600** | **1,255** | **780** | **600** | **660** | **1,204** | **60** | **60** | **965** | **56** |

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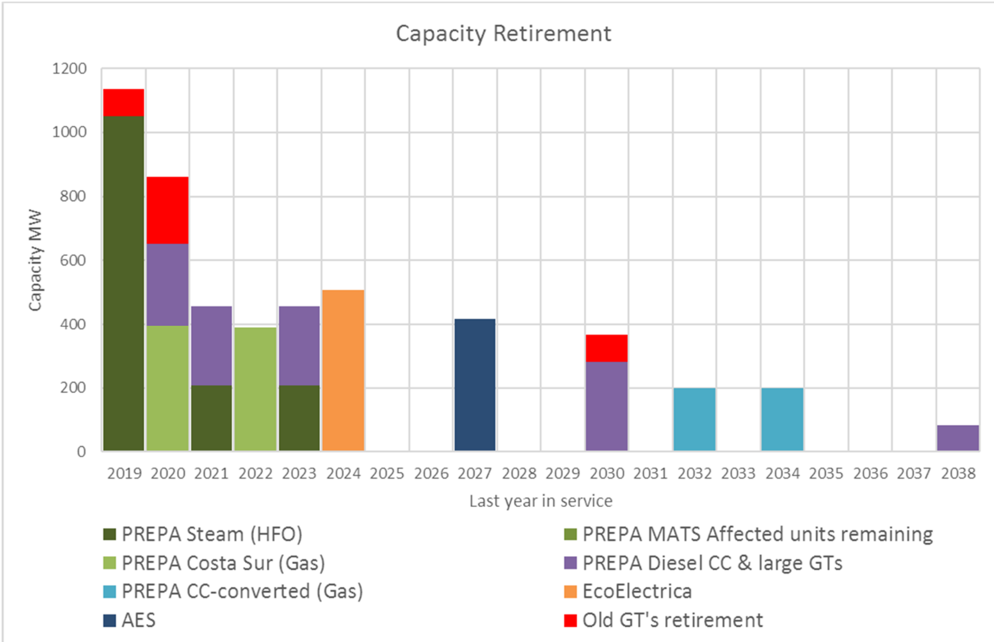
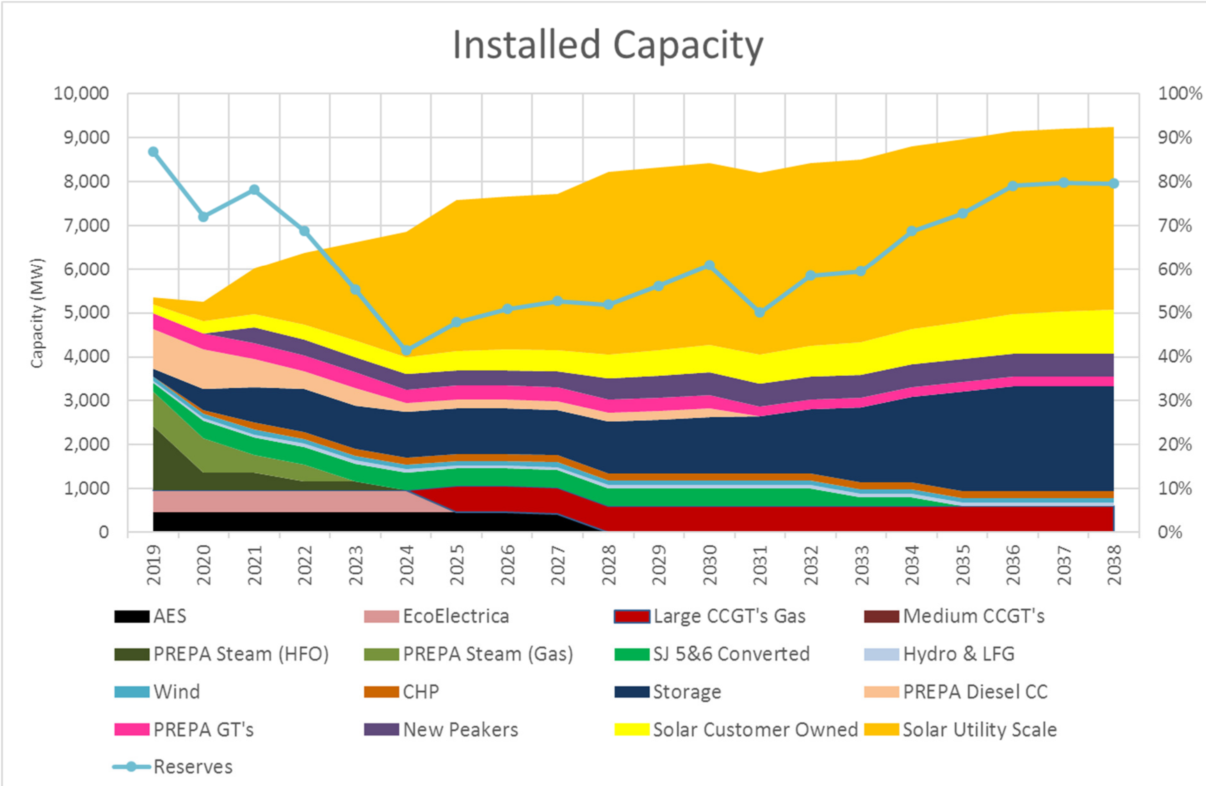
**Exhibit 8-57: Scenario 3 Base Load Forecast Capacity Retirements**




| Capacity by Technology MW | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PREPA Steam (HFO) | 1050 | 0 | 206 | 0 | 206 | 0 | 0 | 0 | 0 | 0 | 0 |
| PREPA MATS Affected units remaining | | | | | | 0 | 0 | 0 | 0 | 0 | 0 |
| PREPA Costa Sur (Gas) | 0 | 393 | 0 | 388 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PREPA Diesel CC & large GTs | 0 | 257 | 249 | 0 | 250 | 0 | 0 | 0 | 0 | 0 | 0 |
| PREPA CC-converted (Gas) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| EcoElectrica | 0 | 0 | 0 | 0 | 0 | 507 | 0 | 0 | 0 | 0 | 0 |
| AES | | | | | | | | | 416 | 0 | 0 |
| **Total Dependable Gen Retirement** | **1050** | **650** | **455** | **388** | **456** | **507** | **0** | **0** | **416** | **0** | **0** |

As PREPA's units and the thermal PPOA's are phased out the operating reserves decline from 87% in 2019 to a low of 41% by 2024, after EcoEléctrica's retirement. The Planning Reserve Margin of 30% appears not to have been binding constraint on the LTCE plan formulation in this scenario and observes a minimum of 38% in 2024.

**Exhibit 8-58: Scenario 3 Future Capacity Mix**




## 8.5.2 Fuel diversity

In line with the change in the energy supply matrix, the system moves away from heavy fuel oil and coal to natural gas along with a sharp drop in overall fuel consumption and associated costs with the implementation of the plan. By 2038, 82% of the generation is coming from renewables.

Fuel consumption declines with the retirements of old Steam gas and heavy fuel oil units and peakers along with EcoEléctrica's retirement by the end of 2024. Overall fuel consumption continues to fall through 2038 despite the new CCGTs in Palo Seco and Costa Sur in 2025. Total fuel consumption drops 85% by 2038 with most of the fuel used coming from natural gas.

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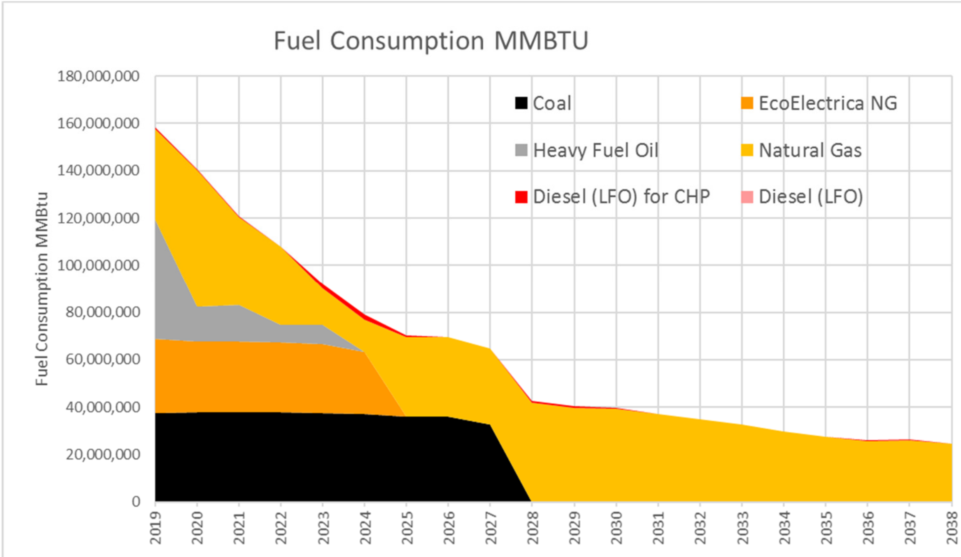
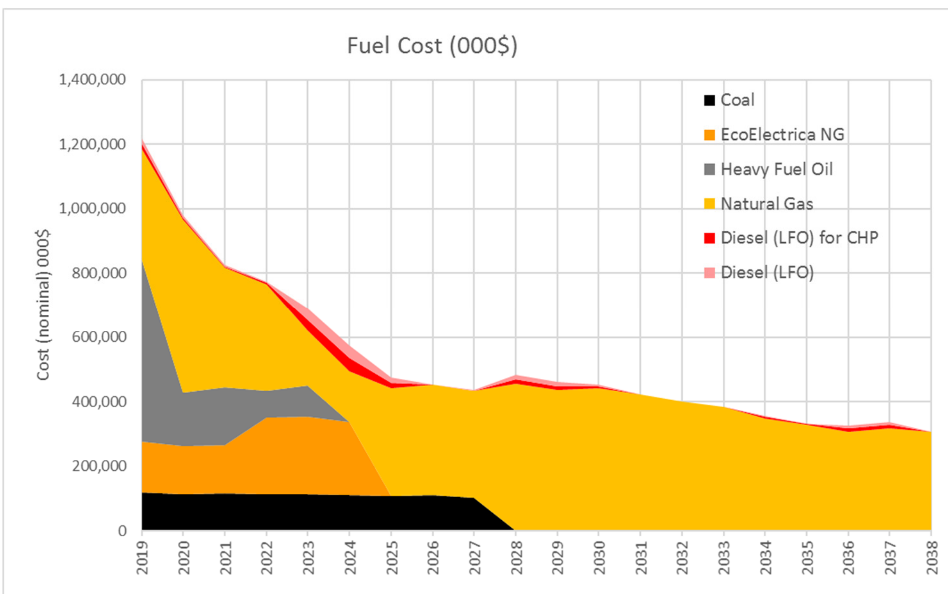
**Exhibit 8-59: Scenario 3 Fuel Consumption**




Fuel costs decline in line with the overall fall in fuel consumption falling to a low of $307 million by 2038 (74% below 2019 levels) with all the retirements, including AES.

**Exhibit 8-60: Scenario 3 Fuel Consumption**




### 8.5.3 **RPS Compliance**

The renewable portfolio standard targets of 12% by 2022, 15% by 2027 and 20% by 2035 are all met and exceeded in the Scenario 3 base case under all strategies. The plan achieved 87% renewable penetration by 2038, far exceeding the proposed regulatory goal of 50% renewable generation by 2040.

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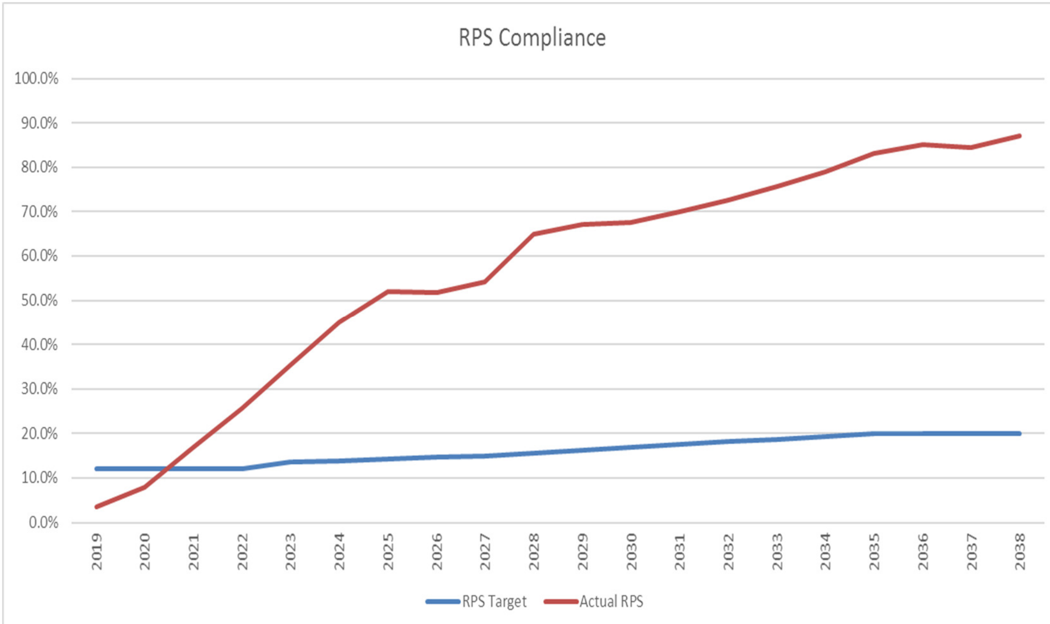
**Exhibit 8-61: RPS Compliance Scenario 3**




### 8.5.4 System Costs

The total cost of supply in real dollars including annualized capital costs, fuel costs, fixed and variable O&M is projected to decline with the implementation of the plan from $ 102.5/MWh in 2019 to $89.8/MWh by 2027 (real $2018), prior to AES Coal retirement. The costs increased in 2028 with the addition of 600 MW of new solar and 126 MW of peakers to fall again in the 2030s due to falling fuel costs to reach $87.7/MWh by 2038.

The net present value of all operating costs reaches $10.1 billion for 2019-2028 (nominal @ 9% rate). Over the study period, the NPV is $14.1 billion. This plan is 2.5% lower in costs over the study horizon.

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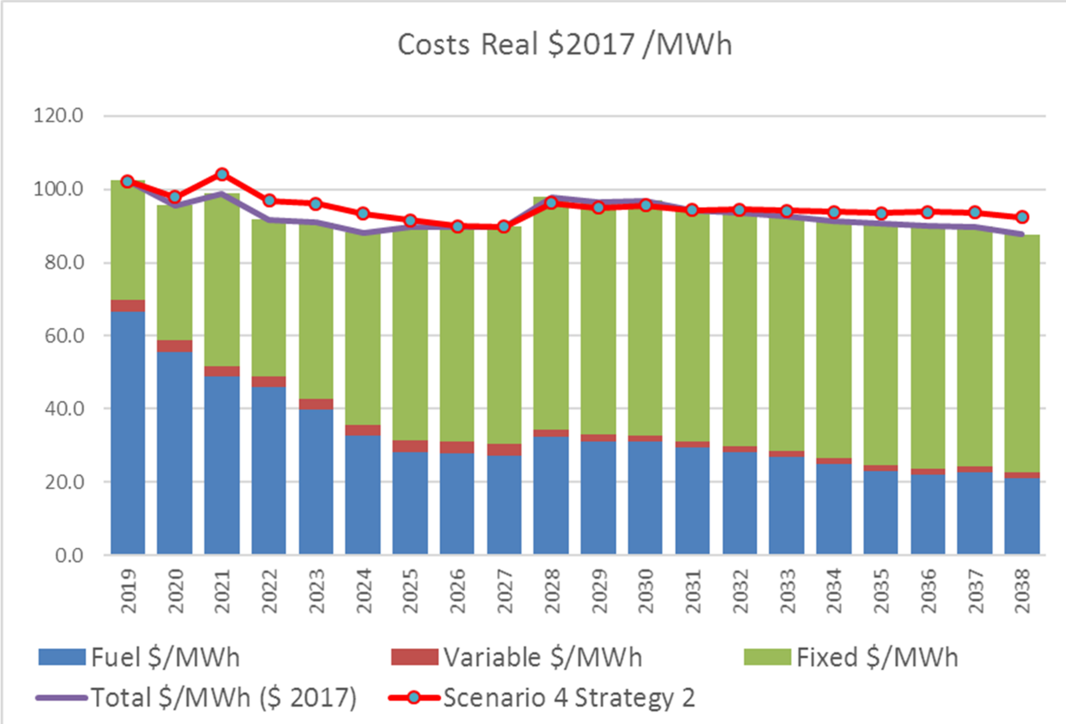
**Exhibit 8-62: Scenario 3 Production Costs**




### 8.5.5 Resiliency (Mini Grid Considerations)

In Scenario 3 plan, the critical loads are met by 2021. After 2022, both critical and priority loads are met for most MiniGrid regions.

Siemens estimated the potential costs from unserved energy in the case of a major hurricane impacting the transmission system[61]. It is assumed that a major hurricane occurs every five years impacting major interconnection transmission lines and placing the system into MiniGrids operation for 1 Month, starting in 2022. It is based on a $2000/MWh cost from unserved energy, which considers that the load shedding will be rotated to minimize impact. The $2000 is consistent with the cost of unserved energy for residential customers[62].

Exhibit 8-17 summarizes the economic costs by MiniGrid region for Scenario 3. The are potential costs for San Juan-Bayamon and Caguas and to a lesser extend in Mayaguez North. Overall, there is an incremental 80 million in potential costs from unserved energy in

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[61] This cost is NOT a forecast of future cost, but rather a high-level determination of how the different portfolios resulting from the combination of scenarios and strategies would perform if every 5 years starting in 2022 a major hurricane impact the island resulting in the operation of the MiniGrids for one month ("Deemed Energy Not Served")

[62] This value is much lower compared to the VOLL determined for PR, in the range of $30,000/MWh

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the case of a major hurricane impacting the island under this plan. This is much lower compared to $228 million for Scenario 4.

**Exhibit 8-63: Cost of Energy Not Served by MiniGrids**

| MiniGrid | NPV Cost ($000) | Strategy 2 |
|---|---|---|
| San Juan-Bayamon | $ 32,101 | $ 8,874 |
| Ponce | $ - | $ - |
| Carolina | $ - | $ 40,737 |
| Caguas | $ 46,423 | $ 127,850 |
| Arecibo | $ - | $ 25,110 |
| Mayaguez-North | $ 1,573 | $ 518 |
| Mayaguez-South | $ - | $ - |
| Cayey | $ - | $ 25,196 |
| Total | $ 80,098 | $ 228,285 |

## 8.6 Scenario 5 Base Case Results

Scenario 5 is a case requested by the Energy Bureau to evaluate how the capacity expansion would look with minimal restrictions. For this in addition to the LNG terminal considered in Scenario 4 the Aguirre Offshore Gas Port (AOGP) is assumed to achieve full permitting and regulatory approval and can move forward. In line with the minimal restriction approach, the scenario reflects a traditional and centralized energy program that emphasizes economic and reliability on a system integrated basis (Strategy 1) without minimum generation requirements to meet peak demand on a regional basis.

Other assumptions in the simulation of this scenario includes gas to Yabucoa (east) and Mayagüez (west) through ship-based LNG, as well as gas to the north through land-based LNG at San Juan. The scenario uses the base case assumption of solar and storage costs and availability. In addition, a larger combined cycle (H-class) could be built in this scenario.

The generation portfolio identified as Scenario 5 Strategy 1 result in a plan that has lower production costs as compared to Scenario 4, about $426 million below. However, the potential costs reductions could be fully offset if the transmission network is impacted by a major hurricane placing the system into MiniGrid operations (the system is segmented in areas). A high-level estimate of the impact shows $1.1 billion of potential costs from energy not served during a month while the transmission system is repaired.

### 8.6.1 Capacity Additions and Retirements

The economic simulation of the Scenario 5 results in 2,160 MW of utility scale PV additions over the study period, only 60 MW below Scenario 4 plan. There is 1,200 MW in 2019-2022, hitting allowed yearly limits, in line with Scenario 4.

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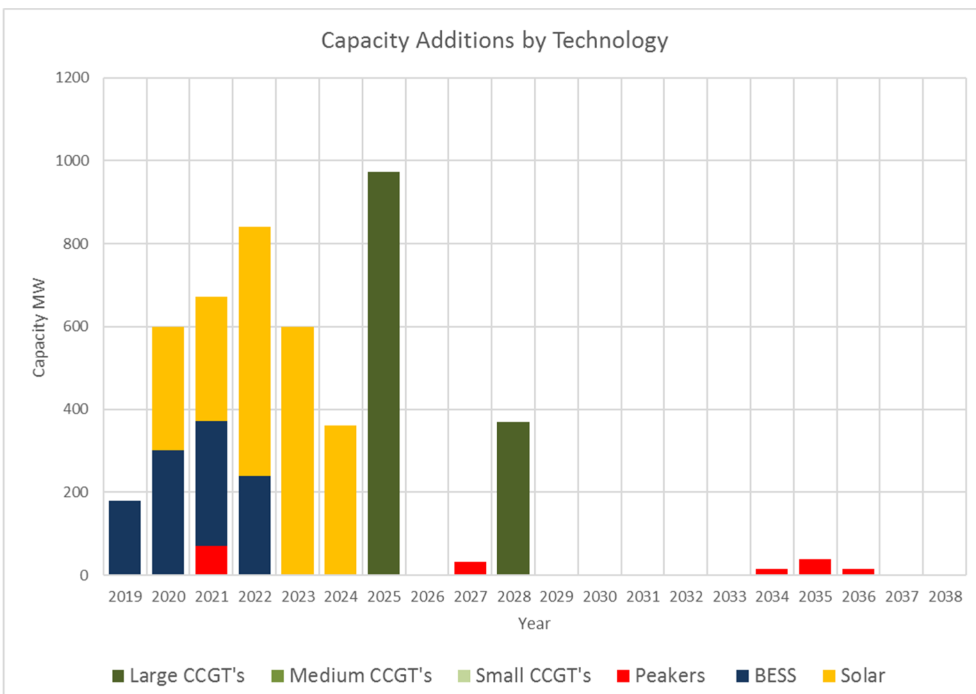
In this scenario, 1,020 MW of battery energy storage is built over the study period, mostly in 2019-2022, reaching the annual installation limits in that period, in line with the plan for Scenario 4.

Four large F class CCGTs are installed, two in Palo Seco (Bayamon) and two in Costa Sur (Ponce west). Due to the addition of large combined cycles, the peaking need in this case is lower than Scenario 4 portfolio with 174 MW.

San Juan 5 and 6 are retired both economically in 2025 after being converted to natural gas in 2019. EcoEléctrica is retired economically in 2024, in line with most scenarios (except for the ESM case that considered further reductions on the capacity payments) and AES retires by the end of 2027, by model input.

The Plan is MATS compliant after 2024 and achieve 49% RPS compliance by 2038 (lower than the scenario 4 portfolio), but in line to achieve 50% penetration by 2040.

**Exhibit 8-64: Scenario 5 Portfolio Capacity Additions**




| Capacity by Technology MW | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Large CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 973 | 0 | 0 | 369 | 0 |
| Medium CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Small CCGT's | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Peakers | 0 | 0 | 71 | 0 | 0 | 0 | 0 | 0 | 32 | 0 | 0 |
| BESS | 180 | 300 | 300 | 240 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Distchable Additions** | **180** | **300** | **371** | **240** | **0** | **0** | **973** | **0** | **32** | **369** | **0** |
| Solar | 0 | 300 | 300 | 600 | 600 | 360 | 0 | 0 | 0 | 0 | 0 |
| **Total Additions** | **180** | **600** | **671** | **840** | **600** | **360** | **973** | **0** | **32** | **369** | **0** |

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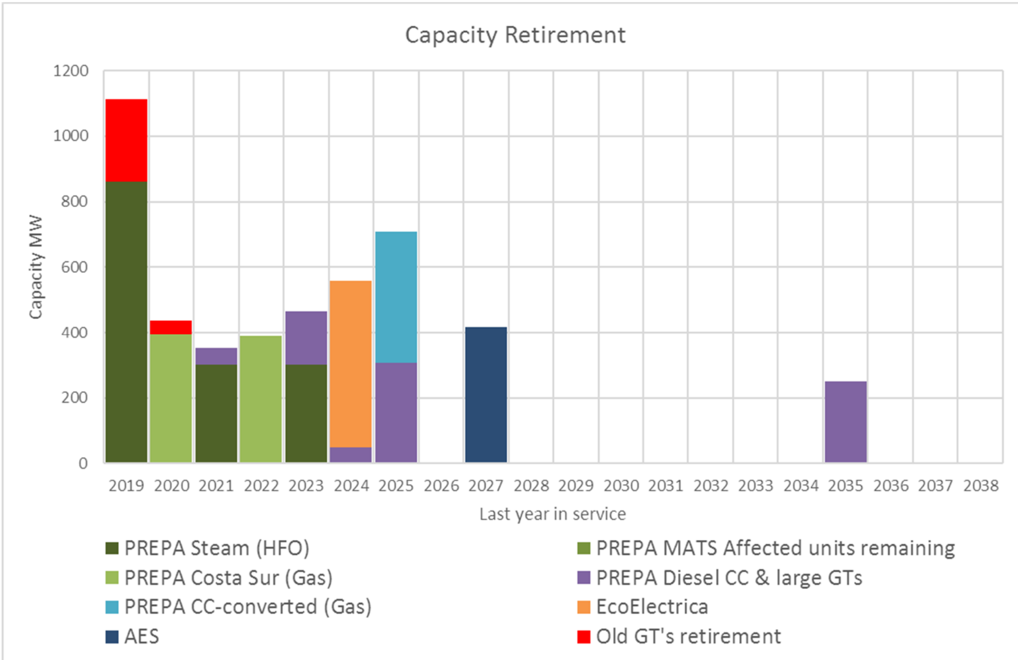
**Exhibit 8-65: Scenario 5 Portfolio Capacity Retirements**




| Capacity by Technology MW | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PREPA Steam (HFO) | 862 | 0 | 301 | 0 | 300 | 0 | 0 | 0 | 0 | 0 | 0 |
| PREPA MATS Affected units remaining | | | | | | 0 | 0 | 0 | 0 | 0 | 0 |
| PREPA Costa Sur (Gas) | 0 | 393 | 0 | 388 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PREPA Diesel CC & large GTs | 0 | 0 | 50 | 0 | 165 | 50 | 307 | 0 | 0 | 0 | 0 |
| PREPA CC-converted (Gas) | 0 | 0 | 0 | 0 | 0 | 0 | 400 | 0 | 0 | 0 | 0 |
| EcoElectrica | 0 | 0 | 0 | 0 | 0 | 507 | 0 | 0 | 0 | 0 | 0 |
| AES | | | | | | | | | 416 | 0 | 0 |
| **Total Dependable Gen Retirement** | **862** | **393** | **351** | **388** | **465** | **557** | **707** | **0** | **416** | **0** | **0** |

As PREPA's units and the thermal PPOA's are phased out the operating reserves decline from 64% in 2019 to a low of 31% by 2028 with the retirement of AES. The Planning Reserve Margin of 30% appears to have a binding constraint on the LTCE plan formulation in this scenario with reserve margins for the system falling near this threshold in 2027-2028 and 2035, however only in 2035 we observe new peaking generation being committed.

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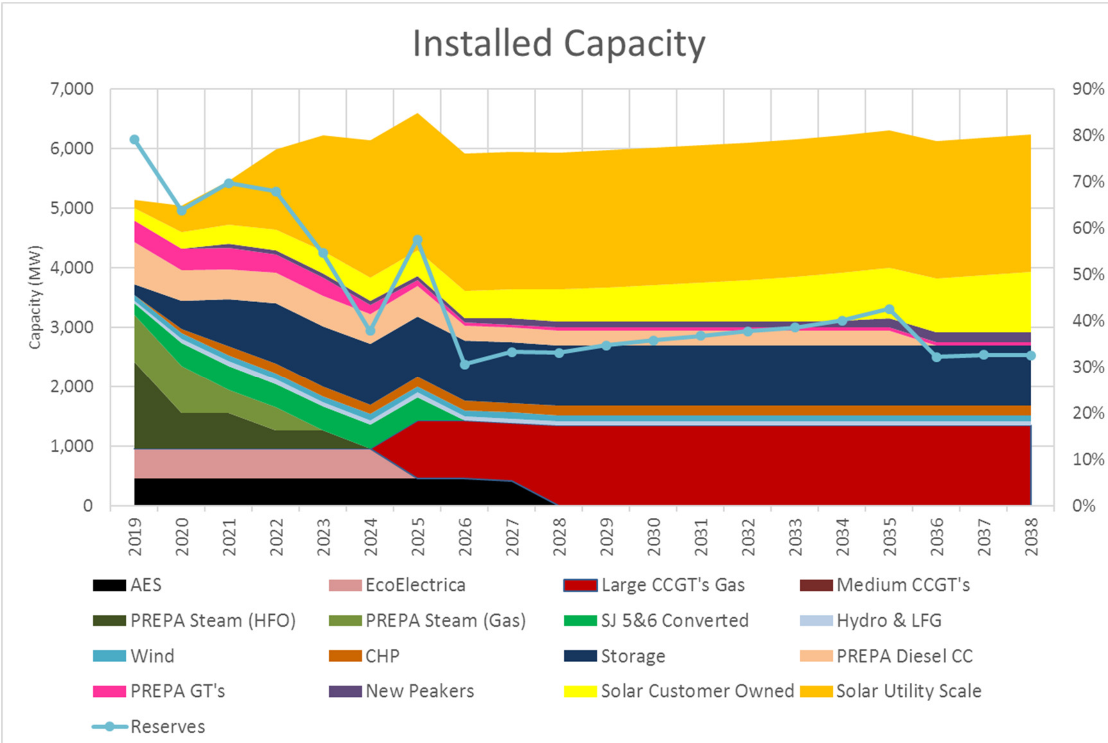
**Exhibit 8-66: Scenario 5 Capacity Mix**




## 8.6.2 Fuel Diversity

In line with the change in the energy supply matrix, the system moves away from heavy fuel oil and coal to natural gas along with a sharp drop in overall fuel consumption and associated costs with the implementation of the plan. Fuel consumption declines with the retirements of old steam gas and heavy fuel oil units and peakers along with EcoEléctrica's retirement by the end of 2024. Total fuel consumption drops 69% by 2038 with most of the fuel used coming from natural gas.

Fuel costs decline in line with the overall fall in fuel consumption falling to a low of $592 million by 2038 (51% below 2019 levels) with all the retirements, including AES.

**Exhibit 8-67: Scenario 5 Fuel Mix**

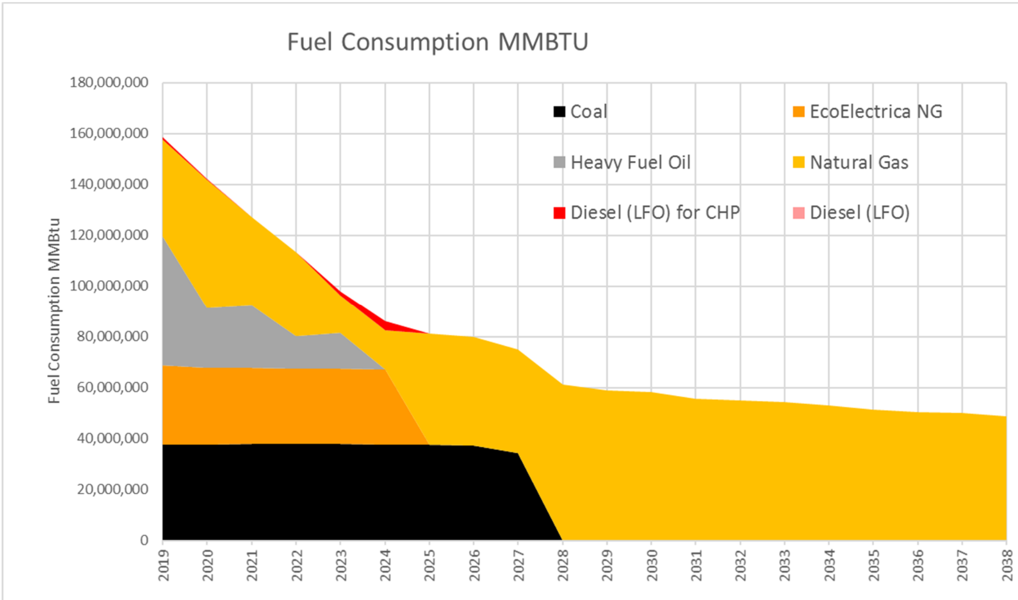
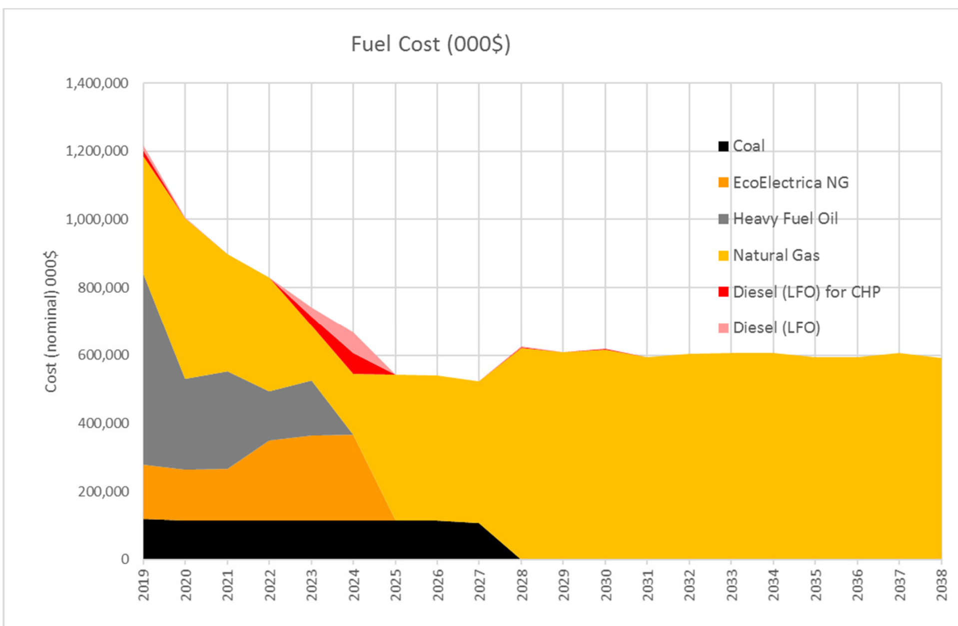


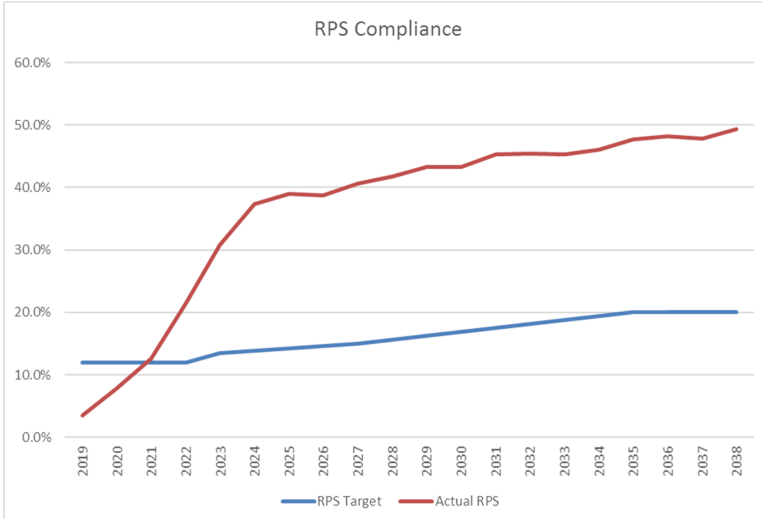

**Exhibit 8-68: Scenario 5 Fuel Costs**




## 8.6.3 RPS Compliance

The renewable portfolio standard targets of 12% by 2022, 15% by 2027 and 20% by 2035 are all met and exceeded in Scenario 5. The plan achieves 49% renewable penetration by 2038, in line to reach the proposed 50% renewable generation by 2040.

**Exhibit 8-69: Scenario 5 RPS Compliance**




### 8.6.4 **System Costs**

The total cost of supply in real dollars including annualized capital costs, fuel costs, fixed and variable O&M is projected to decline with the implementation of the plan from $102/MWh in 2019 to $86.2/MWh by 2026 (real $2018), prior to AES Coal retirement, with the addition of solar and storage and the retirement of older generation. The costs increased in 2028 with AES retirement and the addition of the new CCGT. System costs fall in the last 10 years primarily due to falling fuel costs to reach $88.6/MWh by 2038.

The net present value of all operating costs reaches $10.1 billion for 2019-2028 (nominal @ 9% rate). Over the study period, the NPV is $14.09 billion. This plan is 3% lower in costs over the study horizon compared to Scenario 4.

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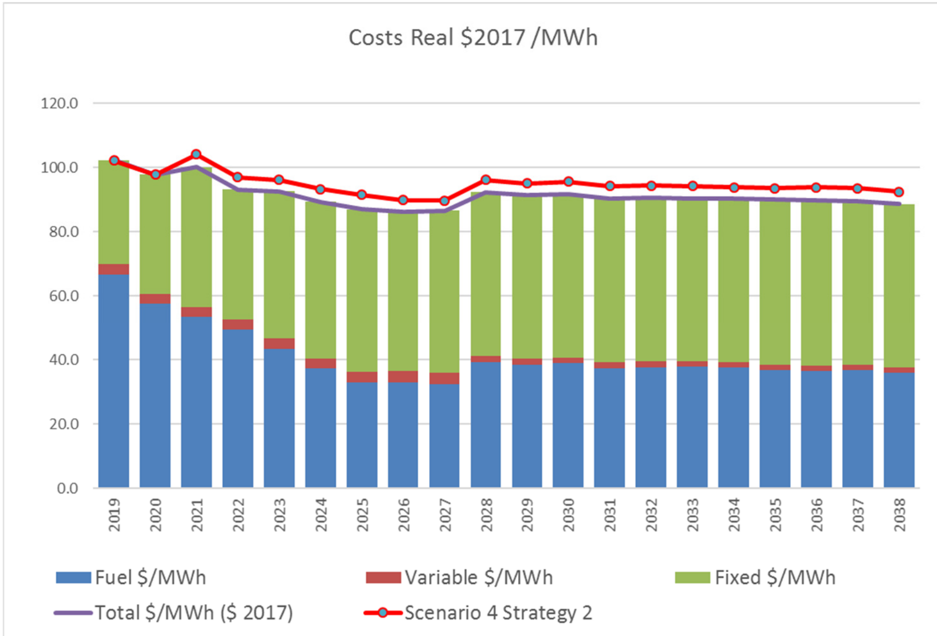
**Exhibit 8-70: Scenario 5 System Costs**




## 8.6.5 Resiliency (Mini Grid Considerations)

In Scenario 5 plan, the critical loads are not met with thermal resources on most MiniGrids, are not met with local generation while the plan is being developed in 2019 through 2022. After 2022, both loads are met for most MiniGrid regions.

Siemens estimated the potential costs from unserved energy in the case of a major hurricane impacting the transmission system[63]. It is assumed that a major hurricane occurs every five years impacting major interconnection transmission lines and placing the system into MiniGrids operation for 1 Month, starting in 2022. It is based on a $2000/MWh cost from unserved energy, which considers that the load shedding will be rotated to minimize impact. The $2000 is consistent with the cost of unserved energy for residential customers[64].

Exhibit 8-71 summarizes the economic costs by MiniGrid region for Scenario 5. There are potential costs for most regions, in particular Caguas, Arecibo and Mayaguez North showing the latest potential impact and costs. Total costs for the system are north of $1.1 billion, $914

[63] This cost is NOT a forecast of future cost, but rather a high-level determination of how the different portfolios resulting from the combination of scenarios and strategies would perform if every 5 years starting in 2022 a major hurricane impact the island resulting in the operation of the MiniGrids for one month ("Deemed Energy Not Served")

[64] This value is much lower compared to the VOLL determined for PR, in the range of $30,000/MWh

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million higher than Scenario 4, basically illustrating the risks to the system of going into a centralized system.

**Exhibit 8-71: Cost of Energy Not Served by MiniGrids (NPV Costs $000)**

| MiniGrid | Scenario 5 | | Scenario 4 | |
|---|---|---|---|---|
| San Juan-Bayamon | $ | 238,176 | $ | 8,874 |
| Ponce | $ | - | $ | - |
| Carolina | $ | 79,227 | $ | 40,737 |
| Caguas | $ | 365,690 | $ | 127,850 |
| Arecibo | $ | 210,830 | $ | 25,110 |
| Mayaguez-North | $ | 110,049 | $ | 518 |
| Mayaguez-South | $ | 71,954 | $ | - |
| Cayey | $ | 66,526 | $ | 25,196 |
| Total | $ | 1,142,452 | $ | 228,285 |

### 8.6.6 Considerations under high gas prices

The Siemens team simulated Scenario 5 under a high gas price case. This resulted in lower gas-fired capacity additions with only two CCGTs being developed, one in Palo Seco and the other one in Costa Sur, both in 2025. Under the high gas case, there is also more peakers added to the system with 374 MW in the planning period, 200 MW higher compared to case with reference gas prices.

There is 180 MW of incremental solar capacity additions supported by an additional 380 MW of battery storage. Solar additions do not change in 2019-2022 with 1,200 MW added.

The overall portfolio costs $648 million higher compared to the simulation with reference gas prices, making the overall portfolio more expensive than Scenario 4. The risk of having unserved load under MiniGrid operations is somewhat reduced with more peakers with an estimated $799 million in costs from unserved energy, $115 million below the simulation with reference gas prices.

## 8.7 Planning Reserve Margin Considerations

### 8.7.1 Introduction

The purpose of this subsection is to discuss Planning Reserve Margin (PRM) in more depth.

As was illustrated above the adopted PRM of 30% was found not to be binding under most conditions and in particular for the plans that are considered to contain the recommended decisions; Scenario 4 Strategy 2 and the ESM plan. However, in this section we review those conditions in which PRM was binding and resulted in new builds. In addition, we provide indication of values to which this PRM could be lowered in the future.

To identify scenarios where PRM was binding, the reserve margin for all scenarios and cases was investigated for all years. For cases where the reserves level was close to 30% (PRM) we evaluated if new peaker units were built in response to the low reserve levels. It should be

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noted here that for the preferred portfolios, S4S2B and ESM, PRM was never a binding constraint, i.e. it did not explicitly trigger new peaker units builds. The cases where PRM was a binding constraint are discussed below.

## 8.8 Binding Planning Reserve Margin Cases

Among all the available portfolios, the following cases were found to have binding PRM conditions, which resulted in new builds.

### 8.8.1 S3S3B

In this portfolio, the PRM level dropped to 31.6% in 2024, taking into consideration demand response with a value of 2.6% of peak demand. This drop can be explained due to the retirement of steam (HFO) and diesel CC units; a total of 606 MW. In 2025, EcoEléctrica (507 MW) is retired and two (2) new large CCGT gas units (604 MW) were added. In addition, two (2) reciprocating diesel units, 16 MW each, were added in 2025. Because of these additions, the PRM level increased to 39.6% in 2025 (including a demand response of 2.8% of peak demand). It is possible that the peakers were triggered by the reduction in reserves, however most of the additions are economic, as in 2025 new CCGT's can come online.

As indicated earlier scenario 3, I already a low cost scenario, as compared with scenario 4, but it contains levels of renewable generation that will be hard to integrate and assumes deeper reduction on renewable. Hence the entry or not of the peakers above did not change the opinion on this case.

### 8.8.2 S3S3H

In this portfolio, the PRM level was reported as 32.9% in 2026, including a demand response of 2.9% of peak demand. In 2027 and 2028 AES units (454 MW) were retired and one (1) new large CCGT gas unit (302 MW) was added. In addition, ten (10) peaker units with a total of 213 MW were added in the years 2027 and 2028, bringing the PRM to 43.7% in 2028 (including a demand response of 3.1% of peak demand). Again, the PRM could have been binding, but the addition of the CCGT is triggered by economics and retirement of AES.

As indicated earlier scenario 3, I already a low cost scenario, as compared with scenario 4, but it contains levels of renewable generation that will be hard to integrate and assumes deeper reduction on renewable. Hence the entry or not of the peakers above did not change the opinion on this case.

### 8.8.3 S4S3B

In the existing S4S3B portfolio, it can be observed that moving from year 2025 into year 2028, there was a total of 1160 MW of thermal generation retirements at San Juan 6 CC, AES 1&2, and diesel CC units, while one (1) new large CCGT gas unit (302 MW) was added. In addition, four (4) peaker units with a total of 115 MW were added in the years 2026 to 2028, bringing the PRM to 31.1% in 2028 (including a demand response of 3.1% of peak demand). In this case the PRM was biding and was investigated further as described below.

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### 8.8.4 S4S1B

In this portfolio, it can be observed that in year 2032, there was a total of 514 MW of thermal generation retirements at PREPA's existing diesel CCGT and GT units. The only thermal new units added in 2032 was a 16 MW diesel reciprocal unit, which brings the PRM to 33.2% in 2032, including a demand response of 3.5% of peak demand. The effect is marginal and towards the end of the period. Also, strategy 1 does not provides adequate levels of local reserves for resiliency.

### 8.8.5 S5S1B

In the existing S5S1B portfolio, in 2027 AES was retired and new generation was added. capacity of 38 MW at AES units, in addition to adding two (2) diesel reciprocating engines with a total capacity of 32 MW. As a result, PRM was reported as 33.6% in 2027, including a demand response of 3.0% of peak demand.

## 8.9 Planning Reserve Margin Sensitivity Analysis

From the previous discussion, it can be noticed that PRM was a binding constraint and triggered new peaker units builds in limited cases. For most of the years PRM was not binding despite of the relatively low reserve levels for reasons discussed in the previous subsection. To examine the impact of reductions in the PRM, the same portfolio discussed above, S4S3B was assessed for the year 2028 with reduced levels of reserves, as discussed below:

1. Control Case: this case represents the original conditions in portfolio S4S3B, i.e. no changes made. As mentioned previously, the PRM level is 31.1% (including 3.1% of demand response) and without any unserved load reported.

2. The new peaking units built in 2027 and 2028 were removed 115 MW. The units include:
   a. Two (2) Aero LM6000 units: each unit has a capacity of 39 MW and they were added in 2027 and 2028.
   b. One (1) Aero GE LM2500 unit: this peaker unit has a capacity of 21 MW and was built in 2027.
   c. One (1) RICE: this unit has a capacity of 16 MW and was built in 2028.

   Because of not building these four peaking units, the PRM level dropped to 26.9%. However, no unserved load was reported. Hence in principle a 27% PRM could have been selected and he units above possibly would not have been built.

3. In addition to not including the generation above, the Cambalache CT2 and CT3 were retired earlier (165 MW) in 2028. As a result, the PRM level dropped to 23.2%, and an unserved load of 102 MWh over 8 hours was reported. The total reported savings for this case is estimated to be $31.3 million, while the unserved energy cost is $3.1 million. However, PREPA's planning limit of 4 loss of load hours (LOLH) is exceeded. It should be noted that for this case, all the unserved load is reported in Carolina Area. Based on the above a PRM of 23% would be aggressive.

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4. In this final test two (2) peaker GTs (100 MW) at Mayaguez were also removed. The reserve dropped under 20% and there was 3621 MWh of unserved load over 123 hours. Not only the unserved duration widely exceeds the 8 hours limit, but also the unserved load cost ($109 million) exceeds the potential savings ($35.3 million). It should be noted that for this case, nthe entire unserved load is reported in Carolina and Bayamon Areas (mostly in Carolina).

Based on the above, it is considered that the PRM of 30% was adequate for this study, but it could be reduced to 27%. Lower value is likely to create loss of load hours.

Part

9

# Caveats and Limitations

*This part is under development and will be included in the next filing.*

Part

10

# Action Plan

*This part is under development and will be included in the next filing.*

Attachment

A

# Gas Pipeline Competition Model

## Gas Pipeline Competition Model (GPCM®)

Siemens utilizes the Gas Pipeline Competition Model (GPCM®) to provide rigorous natural gas market evaluations. GPCM® is an industry-leading modeling tool that Siemens license and adapt to include the most up-to-date assumptions on supply, demand, and infrastructure. These assumptions are updated every quarter, with a full review of inputs in the spring and fall (coordinated with Siemens power market modeling work) and a short-term calibration every summer and winter. With GPCM® Siemens cover the entire interconnected North American natural gas market, including the evolving Mexican natural gas (and related power) market.

For inputs, Siemens utilize leading data sources such as DrillingInfo's ProdCast® tool for natural gas production forecasting. ProdCast® allows Siemens to input its oil and gas price assumptions into the model, providing an iterative calibration opportunity to better refine the supply outlook. On the demand side, Siemens develop its outlook from primary sources, including its own electricity market modeling for power sector natural gas demand. Finally, Siemens regularly monitor updates in pipeline infrastructure in-service dates, capacities, and regulatory requirements to ensure Siemens have the latest outlook for pipeline buildout in its modeling.

As an output from GPCM®, Siemens provide short-term and long-term price and basis forecasting for all major natural gas market and supply area liquid trading points in North America as well as economic pipeline flow analysis. Minor, illiquid, or retired natural gas trading points can also be modeled, upon request. Siemens National model outlook can be customized in the model in many different ways to test variables such as a pipeline cancellation, an unexpected growth or decline trend in production from a particular play, the impact of a new major LNG export facility, or any other number of scenarios.

## GPCM® Model Structure and Capabilities

Mathematically, GPCM® is a network model that can be diagrammed as a set of "nodes" and "arcs". Nodes represent production regions, pipeline zones, interconnects, storage facilities, delivery points, and customers or customer groups. The connections between these nodes are called arcs, which represent transactions and flows. Some of these are supplier deliveries to pipelines, transportation across zones and from one zone to another, transfers of gas by one pipeline to another, delivery of gas into storage, storage of gas from one period to another, withdrawal of gas from storage, and pipeline deliveries of gas to customers.

GPCM® dynamically solves for economic rents, allowing cheaper supplies to be used before more expensive supplies and enabling customers willing to pay more to be served before those willing to pay less. By including the entire system of North American gas production, transmission, storage, consumption, and imports/exports, GPCM® optimizes gas flows in an economically sensible order to produce an economically efficient, market-clearing solution. GPCM® contains more than 200 existing and proposed pipelines, 400 storage areas, 85 production areas, 15 liquefied natural gas (LNG) import/export terminals, and nearly 500 demand centers.

The output from GPCM® consists of the following types of items, which can be exported to an Excel spreadsheet for further analysis and reporting:

- Production and spot market prices by region
- Pipeline receipts from producers by zone
- Pipeline flows from zone to zone
- Transportation prices and discounting by pipeline and zone
- Transfers between pipelines at interconnects
- Injections into and withdrawals from storage
- Deliveries by pipelines to customers
- Gas supply available to each customer in each region
- Market clearing prices in each region

## GPCM® Geography and Granularity

GPCM® covers the North American natural gas market, including the continental United States, Canada, and Mexico. GPCM® also contains a graphical display system to visually analyze interconnections, flows, and other output from the model. Demand forecasts can be manipulated by sector and by state. Supply sources can be manipulated by basin or play. Output data is provided on a monthly basis but can be aggregated up to annual averages. The forecasting horizon extends out to December 2040.

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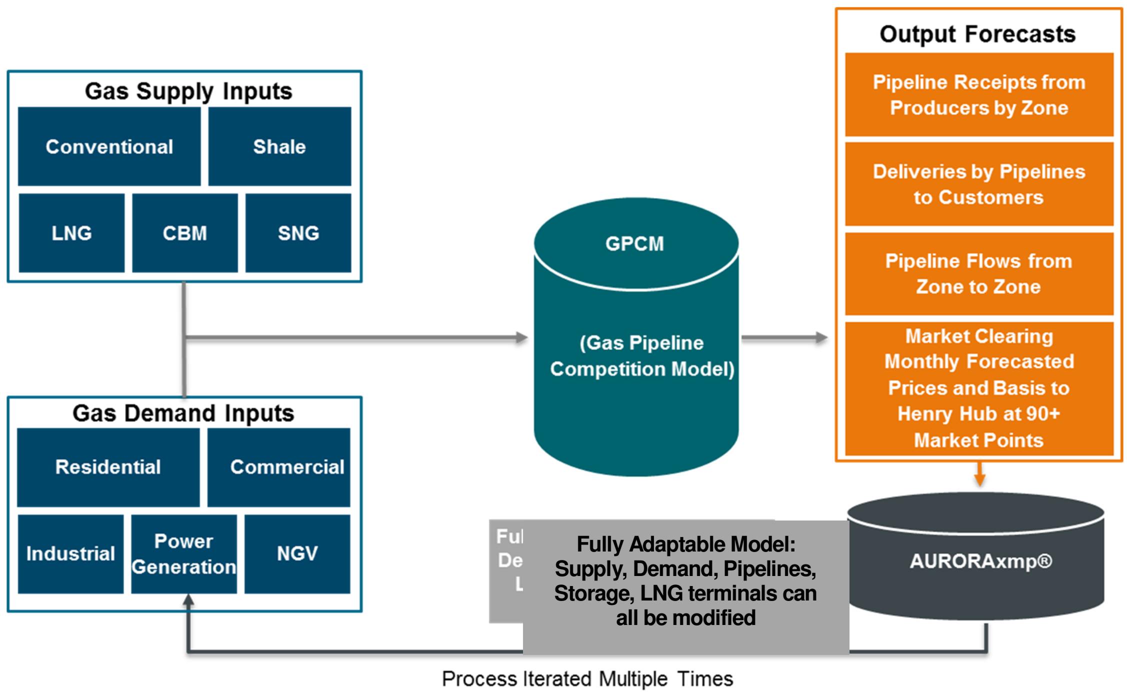
**Figure 10-1. GPCM® and Integration with Power Market Model (AURORAxmp®) [insert caption]**




Source: Siemens

## *GPCM® Power-Gas Model Integration*

The integration of the AURORAxmp® and GPCM® modeling frameworks is one of the cornerstones of Siemens's modeling. At a high level, the GPCM® modeling framework receives inputs from AURORAxmp® on current and expected power sector gas demand based on expected generation capacity additions, coal-gas switching, coal plant retirements, impacts of carbon regime etc. The AURORAxmp® model in turn receives gas pricing inputs based on the supply economics, pipeline expansion plans, and all natural gas consuming sectors of the economy, including power. The final "equilibrated level" is such that gas price levels and the implied power sector gas demand levels are consistent across both models.

It is important to note that initially Siemens develops each of its fundamental market forecasts for natural gas (GPCM®) and power (AURORAxmp®) independently. Once complete, these independent forecasts are then harmonized through the iterative feedback process. Monthly natural gas prices at the benchmark Henry Hub and 60+ major liquid natural gas trading hubs throughout North America developed in GPCM® are used as inputs to the AURORAxmp® model. The output from the power model is then segmented into monthly state level data on natural gas consumption in the power sector. This forecast is then used as an input to the natural gas model, by setting demand targets for power sector gas consumption and by setting the price elasticity of power sector gas demand to zero. When a new set of gas prices and basis forecasts have been computed, a full iteration has been completed. For the second and third iterations, a weighted average of previous iterations is used to dampen oscillations between cycles (for example, a low gas price would encourage high gas burn, which would raise prices, which would lower gas burn, and so forth). Typically, after 3-4 iterations, the models are sufficiently calibrated such that further iterations are not needed.

It should be noted that prior to the harmonization efforts between GPCM® and AURORAxmp®, the gas model undergoes its own balancing with the supply assumptions. DrillingInfo's ProdCast® tool for natural gas production forecasting allows Siemens to input its own crude oil and natural gas price assumptions into the model, providing an iterative calibration opportunity to better refine the natural gas supply outlook. Also, at the macro-economic level, both GPCM® and AURORAxmp® follow internally consistent assumptions around GDP growth rate and the electrical sector demand tied to the GDP growth rate. The GPCM® model also has separate growth rates for the other sectors of the economy.

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## Appendix 1 - PPOAs Under Commercial Operation or in Pre-Operation

### PPOAs Under Commercial Operation as of December 2018

| Name / Contract No. | Contract No. | Capacity (MW) | Technology | Location | Contractual Energy Cost (c/kWh) First Year/Current[1] | Energy Cost Annual Escalator | Contractual REC Cost (c/kWh) | REC Annual Escalator | Annual Capacity Factor[2] | Average Annual Generation (MWh)[3] | Commercial Operation Date |
|---|---|---|---|---|---|---|---|---|---|---|---|
| AES Ilumina, LLC | 2010-P00050 | 20 | Solar PV | Guayama | 15.000 / 16.8924 | 2%; 20 year term | 3.5 | N/A | 0.221 | 38,727.47 | 28-Nov-12 |
| Pattern Santa Isabel, LLC | 2010-P00047 | 95[4] | Wind | Santa Isabel | 12.500 / 13.668 | 1.50%; 20 (+10) year term | 2.5 / 2.734 current | 1.50% | 0.191 | 151,049.61 | 5-Dec-12 |
| Punta Lima Wind Farm, LLC | 2010-AI0001 | 26 | Wind | Naguabo | 12.50 / 13.668 | 1.5%; 20 year term | 2.5 | N/A | 0.230 | 52,301.10 | 17-Dec-12 |
| Windmar Renewable Energy, Inc. (Cantera Martino/La Rita) | 2010-P00052 | 2.1 | Solar PV | Ponce | 15.00 / 17.20 | 2%; 20 year term | 3.5 | N/A | 0.258 | 4,748.34 | 7-Sep-11 |
| San Fermín Solar Farm, LLC | 2011-P00050 | 20 | Solar PV | Loiza | 15.00/15.9 | 2%; 20 year term | 3.5 | N/A | 0.204 | 29,960.81 | 16-Dec-15 |
| Horizon Energy, LLC | 2011-P00034 | 10 | Solar PV | Salinas | 14.3/15.18 | 2%; years 21-25 energy cost fixed @ $208.3 | 3.5 | N/A | 0.259 | 22,654.99 | 18-Aug-15 |
| Landfill Gas Technologies of Fajardo, LLC (Fajardo Landfill) | 2013-P00046 | 2.4 | LandFill Gas | Fajardo | 10 | 0%; 20 year term | 0; granted to PREPA | N/A | 0.378 | 7,222.71 | 1-Oct-16 |
| Oriana Energy, LLC (Yarotek) | 2011-P00048 | 45 | Solar PV | Isabela | 15/15.60 | 2%, 20 year term | 3 | N/A | 0.239 | 84,742.00 | 20-Dec-16 |
| | **Total Capacity** | **220.5** | | | | | | | | | |

### PPOAs Under Pre-Operation as of December 2018

| Name / Contract No. | Contract No. | Capacity (MW) | Technology | Location | Contractual Energy Cost (c/kWh) First Year/Current[1] | Energy Cost Annual Escalator | Contractual REC Cost (c/kWh) | REC Annual Escalator | Expected Annual Capacity Factor[2] | Expected Annual Generation (MWh)[3] | Initial Interconnection Date |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Coto Laurel Solar Farm, Inc. (Windmar Vista Alegre) | 2012-P00052 | 10 | Solar PV | Ponce | 15 | 2%; 20 year term | 3.5 | N/A | 0.220 | 19,272.00 | 17-Nov-16 |
| Humacao Solar Project, LLC (Fonroche Energy America) | 2012-P00031 | 40[5] | Solar PV | Humacao | 15 | 1%; 25 year term | 2.5 | N/A | 0.220 | 77,088.00 | 16-Dec-16 |
| Landfill Gas Technologies of Fajardo, LLC (Toa Baja Landfill)[6] | 2013-P00073 | 2.4 | LandFill Gas | Toa Baja | 10 | 0%; 20 year term | 0; granted to PREPA | N/A | 0.378 | 7,947.07 | 15-Feb-17 |
| | **Total Capacity** | **52.4** | | | | | | | | | |

**Notes:**

1 PPOAs establish an initial energy price and annual escalator, usually a fixed value. The column shows first year price and,in cases where the project is in service and the price has escalated, the energy price as of June 2018.

2 The average annual capacity factor was calcultated using the average of the monthly capacity factors since the facility commenced commercial operation, excluding periods in which the facility was in testing or shut down/curtailed. For those projects still undergoing testing, the expected capacity factor given is the average capacity factor for similar facilities.

3 The average annual generation was calculated using historical data, excep for the Oriana project, which was estimated based on the data since the project entered commercial operation in December 2016. The expected annual generation was calculated using the expected capacity factor.

4 Pattern Santa Isabel - Capacity limited to 75 MW; Capacity can increase to 95 MW during certain months (february to september) but PREPA has not allowed increased until Pattern shows it can meet its Technical Requirements.

5 Humacao Solar Project, LLC - The facility was developed in two phases: phase 1 (20 MW) is under testing and phase 2 (20 MW) is under construction as of June 2018.

6 Landfill Gas Technologies of Fajardo, LLC (Toa Baja Landfill) - The facility completed testing in July of 2017 and was in the process of achieving Commercial Operation when hurricanes Irma and María struck on September 2017. It is expected that the facility will be declared in Commercial Operation in 2018.

## Appendix 2 - PPOAs Not Operational as of December 2018 - 14 PPOAs Under Renegotiation

| | Company | Contract No. | Location | Capacity (MW) | Technology | Expected Capacity Factor[(1)] | Expected Annual Generation (MWh)[(1)] | First Year Energy Purchase Price (c/kWh) | Annual Escalator | REC Purchase Price (c/kWh) | Commercial Operation Date Under Contract | Commercial Operation Date Estimated[(2)] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Desarrollos del Norte, Inc. (Atenas Solar Farm) | 2013-P00070 | Manatí | 20 | Photovoltaic | 0.22 | 38,544 | 14.5 | 2% ; years 21 - 25 energy cost fixed @ yr 20 price | 1.5 | 28-Dec-15 | 1-Jul-19 |
| 2 | Blue Beetle III, LLC | 2012-P00037 | Barceloneta | 20 | Photovoltaic | 0.22 | 38,544 | 14.25 | 2%; years 21-25 energy cost fixed @ 16.0 | 2 | 5-Dec-16 | 1-Jul-19 |
| 3 | CIRO One Salinas, LLC | 2011-P00043 | Salinas | 57 | Photovoltaic | 0.22 | 109,850 | 13.65 | 2%; years 21-25 energy cost fixed @ $15.0 | 3.5 years 1-20; 2.0 years 21-25 | 5-Dec-16 | 1-Jul-19 |
| 4 | Guayama Solar Energy, LLC (GCL) | 2011-P00042 | Guayama | 17.8 | Photovoltaic | 0.22 | 34,304 | 14.1 | 2%; years 21-25 energy cost fixed @ $15.0 | 3.0 years 2-20; 2.0 years 21-25 | 30-Sep-15 | 1-Jul-19 |
| 5 | Xzerta-Tec Solar I, LLC (Grupotec USA) | 2013-P00042 | Hatillo | 20 | Photovoltaic | 0.22 | 38,544 | 15 | 1%; years 21-25 energy cost fixed @ $18.12 | 1.5 | 5-Dec-16 | 1-Jul-19 |
| 6 | Morovis Solar, LLC (Irradia Energy) | 2012-P00053 | Morovis | 33.5 | Photovoltaic | 0.22 | 64,561 | 14.4 | 2%; years 21-25 energy cost fixed @ $20.978 | 2.25 | 5-Dec-16 | 1-Jul-19 |
| 7 | Moca Solar Farm, LLC | 2013-P00003 | Moca | 20 | Photovoltaic | 0.22 | 38,544 | 14 | 2%; years 21-25 energy cost fixed @ $15.00 | 1.75 | 5-Dec-16 | 1-Jul-19 |
| 8 | North Coast Solar, LLC | 2013-P00041 | Quebradillas | 20 | Photovoltaic | 0.22 | 38,544 | 14 | 2%; years 21-25 energy cost fixed @ $15.00 | 1.75 | 5-Dec-16 | 1-Jul-19 |
| 9 | Renewable Energy Authority, LLC (Vega Serena) | 2012-P00045 | Vega Baja | 20 | Photovoltaic | 0.22 | 38,544 | 14.5 | 2%; years 21-25 energy cost fixed @ $14.50 | 2.25 | 21-Dec-15 | 1-Jul-19 |
| 10 | ReSun (Barceloneta), LLC | 2012-P00061 | Barceloneta | 20 | Photovoltaic | 0.22 | 38,544 | 14.5 | 1.75%; years 21-25 energy cost fixed @ $20.16 | 2.5 | 5-Dec-16 | 1-Jul-19 |
| 11 | Solaner Puerto Rico One, LLC | 2012-P00146 | San German | 25 | Photovoltaic | 0.22 | 48,180 | 14.75 | 1.5%, 25 year term | 1.5 | 5-Dec-16 | 1-Jul-19 |
| 12 | SolarBlue Bemoga, LLC | 2013-P00052 | Dorado | 20 | Photovoltaic | 0.22 | 38,544 | 13.75 | 2%; years 21-25 energy cost fixed @ $17.00 | 2 | 5-Dec-16 | 1-Jul-19 |
| 13 | Windmar Renewable Energy, Inc. (Santa Rosa) | 2012-P00080 | Yauco-Guayanilla | 20 | Photovoltaic | 0.22 | 38,544 | 13 | 2%; years 13-25 energy cost fixed @ $16.160 | 3.5 years 1-20; 0 years 21-25 | 5-Dec-16 | 1-Jul-19 |
| 14 | YFN Yabucoa Solar, LLC | 2013-P00049 | Yabucoa | 20 | Photovoltaic | 0.22 | 38,544 | 13 | 2%; years 21-25 energy cost fixed @ $18.940 | 2 | 17-Oct-15 | 1-Jul-19 |
| | | Total = | | 333.3 | | | | | | | | |

**Notes:**

1 The expected capacity factor is estimated to be approximately the same as the average capacity factor of similar facilities in operation. The expected annual genreation was calculated using the expected capacity factor.

2 The estimated Commercial Operation Date is assumed to be the date included in the current draft amendments prepared by PREPA except for the Energy Answers Arecibo PPOA, in which case the date given is as established in the first amendment to the contract.

## Appendix 3 - PPOAs Not Operational as of December 2018 - 33 PPOAs not Renegotiated

| | Company | Contract No. | Location | Capacity (MW) | Technology | Exprected Capacity Factor[1] | Expected Annual Generation (MWh)[1] | First Year Energy Purchase Price (c/kWh) | Annual Escalator | REC Purchase Price (c/kWh) | Commercial Operation Date Under Contract | Estimated |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Aspenall Energies Santa Isabel, LLC | 2012-P00089 | Santa Isabel | 10 | Wind | 0.22 | 19,272 | 12.5 | 1.50% | 2.5 | 13-Dec-14 | TBD |
| 2 | Lajas Solar Project, LLC (Fonroche Energy America, Inc.) | 2013-P00046 | Lajas | 10 | Photovoltaic | 0.22 | 19,272 | 15 (2013)<br>15 (2014)<br>14 (2015) | 2.00% | N/A | 10-Oct-15 | TBD |
| 3 | Solar Project Ponce, LLC (Fonroche Energy America, Inc.) | 2013-P00045 | Naguabo | 30 | Photovoltaic | 0.22 | 57,816 | 15 (2013)<br>15 (2014)<br>14 (2015) | 2.00% | N/A | 10-Oct-15 | TBD |
| 4 | Solar Project San Juan, LLC (Fonroche Energy America, Inc.) | 2013-P00048 | San Lorenzo | 15 | Photovoltaic | 0.22 | 28,908 | 15 (2013)<br>15 (2014)<br>14 (2015) | 2.00% | N/A | 10-Oct-15 | TBD |
| 5 | South Solar Two, LLC (Fonroche Energy America, Inc.) | 2013-P00047 | Cabo Rojo | 30 | Photovoltaic | 0.22 | 57,816 | 15 (2013)<br>15 (2014)<br>14 (2015) | 2.00% | N/A | 10-Oct-15 | TBD |
| 6 | Vega Baja Solar Project, LLC (Fonroche Energy America, Inc.) | 2013-P00050 | Naguabo | 15 | Photovoltaic | 0.22 | 28,908 | 15 (2013)<br>15 (2014)<br>14 (2015) | 2.00% | N/A | 10-Oct-15 | TBD |
| 7 | GG Alternative Energy Corporation | 2013-P00077 | Fajardo | 20 | Photovoltaic | 0.22 | 38,544 | 15 | 2.00% | 1.5 | 26-Dec-15 | TBD |
| 8 | GG Alternative Energy Corporation | 2013-P00071 | Fajardo | 10 | Wind | 0.22 | 19,272 | 12.5 | 1.50% | N/A | 28-Mar-17 | TBD |
| 9 | Hatillo Solar, LLC | 2013-P00074 | Hatillo | 30 | Photovoltaic | 0.22 | 57,816 | 15 | 2.00% | N/A | 13-Dec-15 | TBD |
| 10 | HSEA PR Isla Solar I, LLC | 2013-P00057 | Carolina | 40 | Photovoltaic | 0.22 | 77,088 | 15 | 2.00% | 1.5 | 13-Dec-15 | TBD |
| 11 | Jonas Solar Energy, LLC | 2012-P000140 | Guayanilla | 40 | Photovoltaic | 0.22 | 77,088 | 15 | 2.00% | 3.5 | 9-May-15 | TBD |
| 12 | Juncos Solar Energy, LLC | 2012-P00138 | Juncos | 20 | Photovoltaic | 0.22 | 38,544 | 15 | 2.00% | 2 | 15-May-15 | TBD |
| 13 | Luquillo Solar Plant, LLC (Renewable Energy Authority/REA Energy, LLC) | 2013-P00051 | Río Grande | 20 | Photovoltaic | 0.22 | 38,544 | 15 (2013)<br>15 (2014)<br>14 (2015) | 2.00% | 2 | 10-Oct-15 | TBD |
| 14 | M Solar Generating, LLC | 2012-P00142 | Manatí | 50 | Photovoltaic | 0.22 | 96,360 | 15 | 2.00% | N/A | 9-May-15 (suspended by mutual accord - see note 2) | TBD |
| 15 | REA Energy Ceiba Solar Plant, LLC (Renewable Energy Authority/REA Energy, LLC) | 2013-P00076 | Ceiba | 20 | Photovoltaic | 0.22 | 38,544 | 15 (2013)<br>15 (2014)<br>14 (2015) | 2.00% | 2 | 28-Dec-15 | TBD |
| 16 | REA Energy Hatillo Solar Plant, LLC (Renewable Energy Authority/REA Energy, LLC) | 2013-P00075 | Hatillo | 20 | Photovoltaic | 0.22 | 38,544 | (2013)15 (2014)14 (2015) | 2.00% | 2 | 28-Dec-15 | TBD |
| 17 | Renewable Power Group, Inc. | 2012-P00010 | Canóvanas | 2 | Bio-digestor | 0.8 | 14,016 | 9.2 | Based on US CPI | N/A | 1-Nov-15 | TBD |
| 18 | Renewable Power Group, Inc. | 2012-P0009 | Moca | 1.5 | Landfill Gas | 0.8 | 10,512 | 9.2 | Based on US CPI | N/A | 1-Nov-15 | TBD |
| 19 | Cabo Solar Farm, LLC (Roma Solar, LLC) | 2013-P00069 | Cabo Rojo | 20 | Photovoltaic | 0.22 | 38,544 | 15 (2013)<br>15 (2014)<br>14 (2015) | 2.00% | 2 | 17-Dec-15 | TBD |
| 20 | Caracol Solar, LLC (Roma Solar, LLC) | 2013-P00004 | Añasco | 20 | Photovoltaic | 0.22 | 38,544 | (2013)15 (2014)14 (2015) | 2.00% | 2 | 20-Jul-15 | TBD |

## Appendix 3 - PPOAs Not Operational as of December 2018 - 33 PPOAs not Renegotiated

| | Company | Contract No. | Location | Capacity (MW) | Technology | Exprected Capacity Factor[(1)] | Expected Annual Generation (MWh)[(1)] | First Year Energy Purchase Price (c/kWh) | Annual Escalator | REC Purchase Price (c/kWh) | Commercial Operation Date Under Contract | Commercial Operation Date Estimated |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 21 | Sierra Solar Farm, LLC (Roma Solar, LLC) | 2013-P00072 | Arecibo | 20 | Photovoltaic | 0.22 | 38,544 | 15 (2013)<br>15 (2014)<br>14 (2015) | 2.00% | 2 | 18-Dec-15 | TBD |
| 22 | Sunbeam Caribbean Energy Corp. | 2010-AI0031 | Barceloneta | 10 | Waste to Energy | 0.8 | 70,080 | 10 | Based on US CPI | N/A | 23-Feb-15 | TBD |
| 23 | Tradewinds Energy, LLC (Tradewinds Energy Barceloneta, LLC) | 2012-P00030 | Barceloneta | 75 | Wind | 0.22 | 144,540 | 12.5 | 1.50% | 2.5 | 20-Jan-16 | TBD |
| 24 | Tradewinds Energy, LLC (Tradewinds Energy Vega Baja, LLC) | 2012-P00028 | lanatí/Vega Ba | 50 | Wind | 0.22 | 96,360 | 12.5 | 1.50% | 2.5 | 19-Jan-16 | TBD |
| 25 | Carolina Solar Farm, LLC | 2013-P00067 | Carolina | 20 | Photovoltaic | 0.22 | 38,544 | 15 (2013)<br>15 (2014)<br>14 (2015) | 2.00% | 2 | 21-Dec-15 | TBD |
| 26 | Vega Baja Solar Energy, LLC (One Planet Caribbean, LLC) | 2012-P00139 | Vega Baja | 30 | Photovoltaic | 0.22 | 57,816 | 15 | 2.00% | 2 | 15-May-15 | TBD |
| 27 | Yabucoa Solar, LLC (Western Wind Puerto Rico, Corp./Brookfield) | 2011-P00090 | Yabucoa | 30 | Photovoltaic | 0.22 | 57,816 | 15 | 2.00% | 3.5 | 30-Jun-14 | TBD |
| 28 | Wind to Energy Systems, LLC | 2011-P00101 | Vieques | 20 | Wind | 0.22 | 38,544 | 12.5 | 1.50% | N/A | 30-Mar-14 | TBD |
| 29 | Windmar Renewable Energy, Inc. | 2012-P00095 | Dorado-Toa Baja | 44 | Wind | 0.22 | 84,797 | 12.5 | 1.50% | 2.5 | 23-Feb-15 | TBD |
| 30 | Windmar Renewable Energy, Inc. | 2012-P00079 | )orado-Toa Baj | 20 | Photovoltaic | 0.22 | 38,544 | 15 | 2.00% | 3.5 | 23-Feb-15 | TBD |
| 31 | Windmar Renewable Energy, Inc. | 2012-P00049 | Guayanilla | 18.4 | Wind | 0.22 | 35,460 | 12.5 | 1.50% | 2.5 | 23-Feb-16 | TBD |
| 32 | Windmar Renewable Energy, Inc. | 2008-AI0066C | Guayanilla | 34.5 | Wind | 0.22 | 66,488 | 12.5 | 1.50% | 2.5 | 23-Feb-16 | TBD |
| 33 | Energy Answers Arecibo, LLC | 2010-AI0018 | Arecibo | 79 | Waste to Energy | 0.8 | 553,632 | 11.27[(3)] | based on US CPI[(2)] | See Note 4 | 3-Jun-21 | 3-Jun-21 |
| | | | **Total:** | **874.4** | | | | | | | | |

**Notes:**

1 The expected capacity factor is estimated to be approximately the same as the average capacity factor of similar facilities in operation. The expected annual genreation was calculated using the expected capacity factor.

2 Commercial Operation Date was put on hold by mutual agreement of the parties until DNER site determination is final

3 Energy Answers Contractual Energy Cost, Escalator and REC Cost - Energy Answers' PPOA establishes that the Energy Cost escalates anually, from the Effective Date of the PPOA, (December 4, 2009) based on a formula that considers the US Consumer Price Index (US CPI) and the energy index reflected in the US CPI (Energy CPI), with a 4% annual cap to the escalator. The price listed is that calculated for 2016.

4 Energy Answers RECs - RECs are property of Energy Answers, and if it sells the RECs, it must pay PREPA 1/3 of the net revenues derived from the sale of the RECs, provided that PREPA can use the RECs to meet a local RPS, in which case PREPA must pay Energy Answers for 2/3 of the lesser of (a) the price for equivalent RECs paid by PREPA, or (b) the charges payable by PREPA, corresponding to the RECs produced by Energy Answers) in case it fails to meet the RPS.

**CEPR-AP-2015-0002**

# Update on the Status of Renewable Energy Contracts

## December 2018 Update

As required under Section VII.B.i of the Final Resolution on the Integrated Resource Plan of the Puerto Rico Electric Power Authority, further clarified in the Resolution of April 5, 2017.

## I. Overview

Between 2008 and 2012 the Puerto Rico Electric Power Authority (PREPA) signed 68 renewable power purchase and operating agreements (PPOAs). By January of 2013, 62 contracts remained in effect, with four (4) facilities under commercial operation: AES Ilumina (20 MW in Guayama), Pattern Santa Isabel (95 MW in Santa Isabel), Punta Lima Wind Farm (26 MW in Naguabo) and Windmar Renewable Energy Cantera Martinó/La Rita (2.1 MW in Ponce). As of December 2018, 58 PPOAs remain in effect, totaling 1480.6 MW.

In 2013 PREPA commissioned a Renewable Energy Generation Integration Study, with the goal of establishing how much intermittent renewable energy capacity could be integrated to Puerto Rico's electric system. The study[1], carried out by Siemens, determined that up to 580 MW of utility scale projects could be safely and reliably interconnected to the grid, considering 100% compliance with PREPA's technical requirements, a system peak demand of 3,300 MW, curtailment levels of 2.26% and 64 MW of net metering projects.

Considering the results of the Siemens study, between 2013 and 2014 PREPA renegotiated and successfully carried out amendments to the terms of 18 PPOAs. The PPOAs that were renegotiated were those in an advanced stage of the permitting process as informed by the Puerto Rico Planning Board and the Puerto Rico Management Permits Office (OGPe). These PPOAs, together with those already under operation or in construction, would meet the capacity identified by the Siemens study. Table 1 lists the PPOAs renegotiated in 2013-14.

[1] Copy of the study can be downloaded at https://www2.aeepr.com/Docs/Siemens%20PTI%20Final%20Report%20-%20PREPA%20Renewable%20-%20final-11.pdf

**Table 1. PPOAs Renegotiated in 2013-14**

| Name | Contract No. | Capacity (MW) |
|---|---|---|
| Desarrollos del Norte, Inc. (d/b/a Atenas Solar Farm) | 2013-P00070 | 20 |
| Blue Beetle III, LLC | 2012-P00037 | 20 |
| CIRO One Salinas, LLC | 2011-P00043 | 57 |
| Humacao Solar Project, LLC (Fonroche Energy) | 2012-P00031 | 40 |
| Guayama Solar Energy, LLC (GCL) | 2011-P00042 | 17.8 |
| Horizon Energy, LLC | 2011-P00034 | 10 |
| Xzerta-Tec Solar I, LLC (Grupotec) | 2013-P00042 | 20 |
| Irradia Morovis, LLC | 2012-P00053 | 33.5 |
| Moca Solar Farm, LLC | 2013-P00003 | 20 |
| North Coast Solar, LLC | 2013-P00041 | 20 |
| Oriana Energy, LLC (Yarotek) | 2011-P00048 | 50 |
| Renewable Energy Authority (Vega Serena), LLC | 2012-P00045 | 20 |
| ReSun Barceloneta, LLC | 2012-P00061 | 20 |
| Solaner Puerto Rico One, LLC | 2012-P00146 | 25 |
| SolarBlue Bemoga, LLC | 2013-P00052 | 20 |
| Coto Laurel Solar Farm, Inc. (Windmar Vista Alegre) | 2012-P00052 | 10 |
| Windmar Renewable Energy, Inc. (Santa Rosa) | 2012-P00080 | 20 |
| YFN Yabucoa Solar, LLC | 2013-P00049 | 20 |

As of today, 58 PPOAs remain in effect. These can be categorized as in Commercial Operation (8) or Pre-Operation (3 undergoing tests), and those that have not commenced construction (47). The PPOAs that have not commenced construction can be further categorized as follows:

a. Under renegotiation – 14 of the 18 PPOAs renegotiated in 2013-14.

b. 32 PPOAs not renegotiated – projects that were not renegotiated in 2013-14.

Further detail is given in the following sections

## II. Renewable PPOAs in Operation

As of December of 2018, 11 PPOAs are in either commercial operation or in pre-operation (energized, under testing, and selling energy and renewable energy credits to PREPA). These projects represent 272.9 MW of capacity, distributed as follows:

a. Photovoltaic - 147.1 MW
b. Wind – 121 MW
c. Landfill Gas – 4.8 MW

Table 2 lists the PPOAs in Commercial Operation and Table 3 lists the PPOAs in Pre-Operation

**Table 2. PPOAs in Commercial Operation as of December 2018**

| Name | Contract No. | Location | Technology | Capacity (MW) |
|---|---|---|---|---|
| AES Ilumina, LLC | 2010-P00050 | Guayama | Photovoltaic | 20 |
| Horizon Energy, Inc. (Salinas Solar Farm) | 2011-P00034 | Salinas | Photovoltaic | 10 |
| Landfill Gas Technologies of Fajardo, LLC | 2013-P00044 | Fajardo | Landfill Gas | 2.4 |
| Oriana Energy, LLC (Yarotek, LLC) | 2011-P00048 | Aguadilla | Photovoltaic | 45 |
| Pattern Santa Isabel, LLC | 2010-P00047 | Santa Isabel | Wind | 95 |
| Punta Lima Wind Farm, LLC (Go Green PR) | 2010-AI0001 | Naguabo | Wind | 26 |
| San Fermín Solar Farm, LLC (Coquí Power, LLC) | 2011-P00050 | Loíza | Photovoltaic | 20 |
| Windmar Renewable Energy , Inc. (Cantera Martinó/La Rita) | 2012-P00015 | Ponce | Photovoltaic | 2.1 |
| | | | Total Capacity | 220.5 MW |

**Table 3. PPOAs in Pre-Operation as of December 2018**

| Name | Contract No. | Location | Technology | Capacity |
|---|---|---|---|---|
| Humacao Solar Project, LLC (Fonroche Energy America) | 2012-P00031 | Humacao | Photovoltaic | 40 |
| Coto Laurel Solar Farm, LLC (Windmar Renewable Energy , Inc./Vista Alegre) | 2012-P00052 | Ponce | Photovoltaic | 10 |
| Landfill Gas Technologies of Fajardo, LLC (Toa Baja) | 2013-P00073 | Toa Baja | Landfill Gas | 2.4 |
| | | | Total Capacity | 52.4 MW |

Note that of the 18 PPOAs renegotiated in 2013-14, 2 have achieved commercial operation (Horizon Energy and Oriana Energy) and 2 are undergoing testing (Coto Laurel Solar Farm and Humacao Solar Project).

Appendix 1 includes more detailed information on the PPOAs that are in Commercial Operation or in Pre-Operation.

On September of 2017 Puerto Rico was hit by hurricanes Irma and María, and some of the renewable energy facilities were affected. The Punta Lima Wind Farm in Naguabo was extensively damaged and will require reconstruction. The Humacao Solar Farm facility suffered extensive damage to its second phase (20 MW) which was in construction when the hurricanes hit, and is currently being rebuilt. Other facilities were affected to a lesser degree, and are slowly coming back online. Presently, the following facilities are operating with partial or full capacity:

1. AES Ilumina – Full Capacity
2. Landfill Gas Technologies of Fajardo (Toa Baja Site) – Full Capacity
3. Landfill Gas Technologies of Fajardo (Fajardo Site) – Full Capacity
4. Pattern Santa Isabel – Full Capacity
5. Windmar Renewable Energy - Cantera Martinó – Full Capacity
6. Coto Laurel Solar Farm – Partial Capacity
7. Horizon Energy – Partial Capacity
8. Humacao Solar Project – Partial Capacity
9. Oriana Energy – Partial Capacity
10. San Fermin Solar Farm – Partial Capacity

Punta Lima Wind Farm expects to bring the facility back to operational status by 2019.

## III. Renewable PPOAs not in Operation

Of the 58 renewable PPOAs that are still in effect, 47 have not begun construction. These PPOAs can be divided in two groups: 14 PPOAs under renegotiation (renegotiated in 2014 and not yet built) and 33 PPOAs not renegotiated.

### A. PPOAs Under Renegotiation

Of the 18 PPOAs successfully renegotiated and amended in 2013-14, 14 have not begun construction. Between 2015 and 2016, most of these companies requested additional extensions to the commencement of construction and commercial operation dates established in their PPOAs. Most of the requests were related to the difficulties alleged by the companies in securing financing for their projects due to the financial situation of the Government of Puerto Rico and PREPA. Some companies also requested extensions to finalize with PREPA certain pending technical elements of their projects or to complete the permitting process. After considering the claims made by the companies, on June of 2016 PREPA's Governing Board approved an extension of the contract milestones[2] conditioned to the renegotiation of certain terms of the contracts, as applicable:

a. Modify the dispute resolution clause to replace the arbitration process with the requirement that any dispute that cannot be resolved by the parties would be taken to a court with jurisdiction in Puerto Rico.

[2] The commercial operation date was to be extended by 18 months beginning on the date on which PREPA would issue the titulization bonds.

b. Modify the clause that requires PREPA to reimburse the company for any post effective date tax or environmental cost payable by the company (taxes or fees imposed on the companies after the effective date of their contract).

c. Modify the force majeure definition and related articles.

d. Modify the terms to complete the Agreed Operating Procedures and eliminate the requirement to enter into an interconnection agreement (some contracts require this, but in practice it has proved to be burdensome and may delay the completion of the project).

e. The parties were to renounce any allegation of breach of contract previous to the amendment.

f. Establish that this would be the final extension granted to the contracts.

These extensions and related amendments were approved for 12 of the 14 remaining renegotiated PPOAs: Blue Beetle III, LLC; CIRO One Salinas, LLC; Guayama Solar Energy, LLC; Irradia Morovis, LLC; Moca Solar Farm, LLC; North Coast Solar, LLC; Renewable Energy Authority, LLC; ReSun (Barceloneta), LLC; Solaner Puerto Rico One, LLC; SolarBlue Bemoga, LLC; YFN Yabucoa Solar, LLC; and Xzerta-Tec Solar I, LLC. . Two PPOAs – Windmar Renewable Energy, Inc.(Santa Rosa Solar Farm) and Desarrollos del Norte, Inc. (d/b/a Atenas Solar Farm) had not shown significant development in the past year, and the Governing Board instructed PREPA to further evaluate these cases.

During the second half of 2016 PREPA engaged these companies in an effort to renegotiate their contracts in compliance with the terms approved by its Governing Board. Comments were received and evaluated, and modifications to certain terms are under evaluation by PREPA, significantly:

a. Standardize the clause that requires PREPA to reimburse the company for any post effective date tax or environmental cost payable by the company, by establishing that PREPA would cover the same during the first 18 years of commercial operation, and afterwards it would retain 50 percent of the monthly payment for net electrical output to recover the payments, plus interest, made to the companies related to post-effective date taxes and environmental costs.

b. Modify the dispute resolution clause to require that any dispute that cannot be resolved by the parties be taken to the Puerto Rico Energy Commission, as required under Act 57-2014, as amended.

c. Modify the milestones so that the projects achieve Commercial Operation, tentatively no later than July 1, 2019[3].

[3] PREPA estimates, based on its experience with those projects already in operation, that this timeframe is adequate for the projects to finalize any technical or permitting issues, achieve financial closing, construct and commission the facilities.

The draft amendments with these new terms were completed. However, filing of protection under Title III of PROMESA temporarily halted the renegotiations with the companies.

Appendix 2 gives information on the terms and status of these projects.

### B. PPOAs Not Renegotiated

PREPA is evaluating the course of action to follow with the PPOAs which were not renegotiated, which will depend, among other things, on the renegotiated PPOAs that will finally enter operation.

Appendix 3 gives information on the terms and status of these projects.

** DRAFT ** **Siemens PTI Report Number: RPT-001-19**

# *Puerto Rico Integrated Resource Plan 2018-2019*
# *Appendix 4: Demand Side Resources*

Draft for the Review of the Puerto Rico Energy Bureau

Prepared for

**Puerto Rico Electric Power Authority**

Submitted by:
Siemens Industry

Rev. [0]
1/22/2018

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v16

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**Revision History**

| Date | Rev. | Description |
|---|---|---|
| 1/22/2018 | 0 | Initial draft |

** DRAFT **

# Contents

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Section

1

# Introduction

This Appendix 4 is focused on the assessment of distributed energy resources that include the following:

1. **Energy Efficiency and Demand Response (EE and DR respectively):** This can be one of the most cost-effective resources to provide the services and comfort that customers with more efficient use of electric resources. This section also covers the participation of the load in providing reserves.

2. **Distributed Generation (DG):** this covers the forecast of the expected penetration of distributed generation and the likely costs that the customers will incur over time. These distributed generation costs are used as a reference to assess customers alternatives with the cost of supply that they may receive from the utility.  A "Grid Defection Option" is also presented here that estimates the costs that customers would incur if were to install solar PV and Storage in amounts enough to become independent and able to have near zero exchanges with the utility.

3. **Combined Heat and Power (CHP)**: CHP although a distributed generation resource, CHP is presented separately as it was considered in two ways; as a forecast based on current known projects and was given as an option to the Long Term Capacity Expansion plan.

Section
2

# Energy Efficiency and Demand Response

Energy efficiency (EE) and demand response (DR) measures can serve as cost-effective and clean demand-side resources. To date, PREPA's demand-side program offerings have largely been energy efficiency conservation campaigns. The Puerto Rico Energy Public Policy Office (EPPO) has also offered efficiency programs focused on low income customers but the tracking and reporting of associated savings was limited. The Puerto Rico Energy Commission Regulation 9021: Regulation on Integrated Resource Plan for the Puerto Rico Electric Power Authority, specifically requires that the IRP consider demand side resources, including EE and DR, as a means to satisfy electric demand over the study period.

To reasonably project EE and DR for the IRP, first a list of potential measures was developed based on effective programs implemented in similar climates and island settings that would yield measurable savings. PREPA reviewed this list and filtered down the measures to a subset which were deemed most appropriate for PREPA customers. These measures were then evaluated and characterized using models which forecast estimates of the program impacts based on participation rates, energy savings, and program costs. The following sections describe the details of the estimated benefits and associated costs from new demand side measures.

## 2.1 Energy Efficiency

The initial list of potential energy efficiency measures considered included residential and commercial lighting, residential and commercial air conditioning, efficient refrigerator rebates, low income weatherization measures, residential ceiling insulation, residential solar water heaters, and advanced residential new construction building codes. This broad list was presented to PREPA and discussed to further assess the feasibility and potential magnitude of energy savings. The Puerto Rico EPPO manages two EE programs; the Weatherization Assistance Program (WAP) and Low Income Home Assistance Program – LIHEAP (similar to the WAP), through the Department of Family Affairs. EPPO provided PREPA some insight regarding both programs. The refined list of energy efficiency projects determined to be the most practical and likely to result in the greatest energy savings is presented in Exhibit 2-1. Detailed projections for these measures were then developed for inclusion in the IRP.

**Exhibit 2-1. Summary Energy Efficiency Measures**

| EE Program | Program Description | Rationale | Key Assumptions | Est. Cost Effectiveness Range (TRC[1]) |
|---|---|---|---|---|
| Residential A/C | Incentivizes higher efficiency A/C units in existing homes | Residential consumption represented ~36% of PREPA's total energy load in 2017, and space cooling is a major component of this consumption. This measure provides rebates for the installation of higher efficiency 12 EER A/C units. | Participation rates, energy savings, and program costs are based on comparable programs with adjustments made for Puerto Rico to account for the prevalence of window and split A/C units in homes. | 3 - 5 |
| Residential Lighting | Provides free LEDs to residential customers | This measure provides LED bulbs to residential customers with 5 per customer and 60W equivalent bulbs. This measure offers an option for the nearly 1/3 of customers who rent their residence. Similar lighting projects have also been used in Barbados and Jamaica (Pilot). | Participation rates increase up to 2.5% annually where participants are using incandescent lamps as a baseline | 4 - 6 |
| Commercial A/C | Incentivizes higher efficiency A/C systems in existing commercial buildings | This measure provides an incentive for the installation of more efficient (17 SEER) 5-ton A/C systems in commercial buildings. A prescriptive 5-ton unit size was used to model this measure to simplify the initial program design. Comparable programs are offered by mainland U.S. utilities in Florida and in many other states. | This program model had to assume typical commercial building A/C sizes. Industry calculators were used to estimate the resulting savings from the higher efficiency A/C unit. | 1 - 2 |
| Commercial Lighting | Incentivizes installation of high efficiency lighting in commercial buildings | This measure provides commercial customers with a rebate for efficient lighting retrofits which is based on a $ / kW reduction in lighting demand resulting from the retrofit and considers different lighting technologies. Comparable programs are offered by mainland U.S. utilities in Florida and in many other states. | A significant assumption is the annual kWh savings per participant, which was based on a review of comparable lighting programs. This estimate could be better informed by more granular data on commercial building loads in Puerto Rico should this data become available. | 3 - 4 |
| Public Street Lighting | Funded full conversion of public street lighting to LED lamps | Street lighting historically accounted for around 2 percent of PREPA's total load. New and more efficient technologies exist and are cost competitive. A full conversion of Puerto Rico's public street lighting, from conventional incandescent lamps to LED, phased in over 5 years. | A key assumption to this measure is that public funding for this project is available. | n/a |
| Residential Rebuilding Efficiency | Rebuilding Hurricane destroyed and damaged homes with higher efficiency cooling, appliances and lighting | Additional efficiency is assumed as the remaining homes are rebuilt and restored. | Efficiency savings based on aligned with FOMB Financial Plan | n/a |

[1] Total Resource Cost (TRC) test. The TRC is calculated as the present value of the avoided energy cost (energy savings x average rate) to the present value of the program costs. The present value was determined using a discount rate of 8.5% and for the average rate we are currently using 25 cents/kWh. However, this rate is expected to reduce and will reassessed once the IRP is complete.

Source: Newport Partners, LLC, PREPA

The ranges TRCs are based on key assumed inputs for PREPA and a review of comparable programs in the U.S. including utilities in Florida, Hawaii, Massachusetts, and Illinois. Most existing programs are well established, have large numbers of participants, and are part of a larger portfolio of energy efficiency and demand response programs. In initial piloting of these measures, PREPA metrics may be more variable and actual TRC values may be lower relative to the estimated range.

### 2.1.1 Residential Air Conditioning

This program offers residential customers an incentive to install a higher efficiency air-conditioning equipment in their home, which will reduce cooling energy consumption. Window units are assumed to be eligible.

Key assumptions underlying the projected costs and energy savings for residential air conditioning incentives as an energy efficiency measure include:

- Participation ranges from one to four percent of eligible residential customers in for the initial years of the program offering;
- Participants receive a $50 incentive towards the purchase of more efficient window units;
- Additional administrative costs are assumed to implement the program;
- Average annual energy savings are assumed to be 500 kWh for window units based on Energy Star program data;
- The window air conditioning unit program assumes a 10 year unit life and the program running from 2019 to 2023 and then sun setting through 2028 after which the program resumes as the original units reach their end of life.

The TRC of this program was calculated to be 4.4 and with a program plus incentives cost of 6.0 cents/kWh[2], this last value calculated by dividing the Present Value of the program and incentives costs with a Weighted Average Cost of Capital (WACC) of 8.5% over the present value of the program energy savings using the same discount rate. Without discounting the cost is 4.5 cents/kWh. A summary of the residential air conditioning program energy savings and program costs is presented in Exhibit 2-2.

[2] To account for continued life of assets beyond the end the program we continued the savings for 10 years after the last programmed expenditure.

**Exhibit 2-2. Residential Air Conditioning Projections**

| | Participant Costs | Utility Program Costs (nominal$) | Utility Incentive Costs (nominal$) | Total Costs (excluding incentives) (nominal$) | Annual MWh Savings - TOTAL |
|---|---|---|---|---|---|
| 2019 | $602,407 | $3,012,035 | $1,004,012 | $3,614,441 | 10,040 |
| 2020 | $928,134 | $4,640,672 | $1,516,559 | $5,568,806 | 25,206 |
| 2021 | $1,271,099 | $6,355,493 | $2,036,234 | $7,626,591 | 45,568 |
| 2022 | $326,399 | $1,631,995 | $512,622 | $1,958,394 | 50,694 |
| 2023 | $335,258 | $1,676,288 | $516,210 | $2,011,545 | 55,856 |
| 2024 | $0 | $0 | $0 | $0 | 55,856 |
| 2025 | $0 | $0 | $0 | $0 | 55,856 |
| 2026 | $0 | $0 | $0 | $0 | 55,856 |
| 2027 | $0 | $0 | $0 | $0 | 55,856 |
| 2028 | $0 | $0 | $0 | $0 | 55,856 |
| 2029 | $1,181,075 | $5,905,377 | $1,614,822 | $7,086,452 | 61,964 |
| 2030 | $1,213,130 | $6,065,649 | $1,626,126 | $7,278,779 | 63,060 |
| 2031 | $1,246,054 | $6,230,271 | $1,637,509 | $7,476,325 | 59,073 |
| 2032 | $1,279,872 | $6,399,360 | $1,648,971 | $7,679,232 | 70,436 |
| 2033 | $1,314,608 | $6,573,039 | $1,660,514 | $7,887,647 | 81,879 |
| 2034 | $0 | $0 | $0 | $0 | 81,879 |
| 2035 | $0 | $0 | $0 | $0 | 81,879 |
| 2036 | $0 | $0 | $0 | $0 | 81,879 |
| 2037 | $0 | $0 | $0 | $0 | 81,879 |
| 2038 | $0 | $0 | $0 | $0 | 81,879 |
| **Total** | **$9,698,035** | **$48,490,177** | **$13,773,578** | **$58,188,212** | **1,212,457** |

Source: Newport Partners, LLC

### 2.1.2 Residential Lighting

This program offers residential customers a voucher for five free LED bulbs (60 W equivalent). This is assumed to be a standalone program here but could be combined with a home energy audit program which could qualify customers for other energy efficiency programs. This measure would also be applicable to the nearly one third of PREPA's residential customers who are renters. The measure also helps reduce evening peak loads.

Key assumptions underlying the projected costs and energy savings for residential lighting incentives as an energy efficiency measure include:

- Participation increases to 2.5 percent of eligible customers participating in the program in the early years of the offering;
- There is no additional cost to participants;
- Additional administrative costs are assumed to implement the program; and

- Annual household energy savings assumed to be 172 kWh based on the assumed five replacement bulbs operating for 2 hours per day and replacing incandescent bulbs.

The TRC of this program was calculated to be 5.9 and with a program plus incentives cost of 4.2 cents/kWh[3], this last value calculated by dividing the Present Value of the program plus incentives costs with a WACC of 8.5% over the present value of the energy savings using the same discount rate. Without discounting the cost is 2.3 cents/kWh. A summary of the residential lighting program energy savings and program costs is presented in Exhibit 2-3.

**Exhibit 2-3. Residential Lighting Projections**

| | Participant Costs | Utility Program Costs (nominal$) | Utility Incentive Costs (nominal$) | Total Costs (excluding incentives) (nominal$) | Annual MWh Savings - TOTAL |
|---|---|---|---|---|---|
| 2019 | $0 | $870,143 | $0 | $870,143 | 2,297 |
| 2020 | $0 | $1,787,518 | $0 | $1,787,518 | 6,922 |
| 2021 | $0 | $2,295,039 | $0 | $2,295,039 | 12,744 |
| 2022 | $0 | $2,357,326 | $0 | $2,357,326 | 18,606 |
| 2023 | $0 | $2,421,304 | $0 | $2,421,304 | 24,510 |
| 2024 | $0 | $2,487,018 | $0 | $2,487,018 | 30,455 |
| 2025 | $0 | $2,554,516 | $0 | $2,554,516 | 36,442 |
| 2026 | $0 | $2,623,845 | $0 | $2,623,845 | 42,470 |
| 2027 | $0 | $2,695,056 | $0 | $2,695,056 | 48,541 |
| 2028 | $0 | $2,768,200 | $0 | $2,768,200 | 54,654 |
| 2029 | $0 | $2,843,329 | $0 | $2,843,329 | 60,810 |
| 2030 | $0 | $2,920,497 | $0 | $2,920,497 | 67,010 |
| 2031 | $0 | $2,999,759 | $0 | $2,999,759 | 73,252 |
| 2032 | $0 | $3,081,173 | $0 | $3,081,173 | 79,538 |
| 2033 | $0 | $3,164,796 | $0 | $3,164,796 | 85,869 |
| 2034 | $0 | $3,250,688 | $0 | $3,250,688 | 92,243 |
| 2035 | $0 | $3,338,912 | $0 | $3,338,912 | 98,662 |
| 2036 | $0 | $3,429,530 | $0 | $3,429,530 | 105,126 |
| 2037 | $0 | $3,522,608 | $0 | $3,522,608 | 111,636 |
| 2038 | $0 | $3,618,211 | $0 | $3,618,211 | 118,191 |
| **Total** | **$0** | **$55,029,468** | **$0** | **$55,029,468** | **1,169,978** |

Source: Newport Partners, LLC

### 2.1.3 Commercial Air Conditioning

This program offers commercial customers an incentive to install a more efficient air-conditioning system in their commercial buildings, which will reduce cooling energy consumption. A prescriptive 5-ton, 17 SEER unit size was used to model this measure to

[3] To account for continued life of assets beyond the end the program we continued the savings for 10 years after the last programmed expenditure.

simplify the initial program design. Comparable programs are offered by mainland U.S. utilities in Florida and in many other states.

Key assumptions underlying the projected costs and energy savings for commercial air conditioning incentives as an energy efficiency measure include:

- On average between one half and one percent of eligible commercial customers participate;
- All participants use central air conditioning and receive a $700 incentive towards a more efficient unit;
- Additional administrative costs are assumed to implement the program;
- Average annual energy savings are assumed to be 1,750 kWh for commercial systems based on a range of SEER calculators and reported savings from Florida utility reported program savings programs; and
- The commercial air conditioning unit program assumes a 15 year unit life.
- The commercial air conditioning unit program assumes that program sunsets after 8 years due to maximized participation and optimized costs/savings. The program resumes in Year 16 to reflect 15-year unit life and need for replacement.

The TRC of this program was calculated to be 2.0 and with a program plus incentives cost of 8.0 cents/kWh[4], this last value calculated by dividing the Present Value of the program plus incentives costs with a WACC of 8.5% over the present value of the energy savings using the same discount rate. Without discounting the cost is 4.7 cents per kWh. A summary of the commercial air conditioning program energy savings and program costs is presented in Exhibit 2-4.

[4] To account for continued life of assets beyond the end the program we continued the savings for 10 years after the last programmed expenditure.

**Exhibit 2-4. Commercial Air Conditioning Projections**

| | Participant Costs | Utility Program Costs (nominal$) | Utility Incentive Costs (nominal$) | Total Costs (excluding incentives) (nominal$) | Annual MWh Savings - TOTAL |
|---|---|---|---|---|---|
| 2019 | $924,753 | $308,251 | $431,551 | $1,233,003 | 1,079 |
| 2020 | $943,248 | $314,416 | $431,551 | $1,257,663 | 2,158 |
| 2021 | $1,443,169 | $481,056 | $647,327 | $1,924,225 | 3,776 |
| 2022 | $1,472,032 | $490,677 | $647,327 | $1,962,710 | 5,394 |
| 2023 | $1,501,473 | $500,491 | $647,327 | $2,001,964 | 7,013 |
| 2024 | $1,531,502 | $510,501 | $647,327 | $2,042,003 | 8,631 |
| 2025 | $1,562,132 | $520,711 | $647,327 | $2,082,843 | 10,249 |
| 2026 | $1,593,375 | $531,125 | $647,327 | $2,124,500 | 11,868 |
| 2027 | $0 | $0 | $0 | $0 | 11,868 |
| 2028 | $0 | $0 | $0 | $0 | 11,868 |
| 2029 | $0 | $0 | $0 | $0 | 11,868 |
| 2030 | $0 | $0 | $0 | $0 | 11,868 |
| 2031 | $0 | $0 | $0 | $0 | 11,868 |
| 2032 | $0 | $0 | $0 | $0 | 11,868 |
| 2033 | $0 | $0 | $0 | $0 | 11,868 |
| 2034 | $1,866,893 | $622,298 | $647,327 | $2,489,190 | 13,486 |
| 2035 | $1,904,231 | $634,744 | $647,327 | $2,538,974 | 15,104 |
| 2036 | $1,942,315 | $647,438 | $647,327 | $2,589,754 | 16,723 |
| 2037 | $1,981,161 | $660,387 | $647,327 | $2,641,549 | 18,341 |
| 2038 | $2,020,785 | $673,595 | $647,327 | $2,694,380 | 19,959 |
| **Total** | **$20,687,068** | **$6,895,689** | **$7,983,697** | **$27,582,757** | **216,854** |

Source: Newport Partners, LLC

### 2.1.4 Commercial Lighting

This program offers commercial customers a rebate for replacing existing interior lighting fixtures or lamps with high efficiency lamps. The $/kW incentive should make this type of program attractive to commercial customers since there is such variation in lighting types across commercial buildings. However, a significant assumption is the annual kWh savings per participant, which was based on a review of comparable lighting programs. This estimate could be better informed by more granular data on commercial building loads and the breakdown of end use loads for Puerto Rico should this data become available.

Key assumptions underlying the projected costs and energy savings for commercial lighting incentives as an energy efficiency measure include:

- On average two percent of eligible customers participate in the program;
- The program sunsets after ten years;
- The cost of retrofit is $7,800, of which the utility offers a 50% rebate to customer;
- Additional administrative costs are assumed to implement the program; and
- Annual participant energy savings assumed to be 15,000 kWh based on comparable programs in the U.S.

The TRC of this program was calculated to be 3.15 and with a program plus incentives cost of 4.5 cents/kWh[5], this last value calculated by dividing the Present Value of the program plus incentives costs with a WACC of 8.5% over the present value of the energy savings using the same discount rate. Without discounting the cost is 2.6 cents/kWh. A summary of the commercial lighting program energy savings and program costs is presented in Exhibit 2-5.

**Exhibit 2-5. Commercial Lighting Projections**

| | Participant Costs | Utility Program Costs (nominal$) | Utility Incentive Costs (nominal$) | Total Costs (excluding incentives) (nominal$) | Annual MWh Savings - TOTAL |
|---|---|---|---|---|---|
| 2019 | $9,617,426 | $2,466,007 | $4,808,713 | $12,083,433 | 18,495 |
| 2020 | $19,619,549 | $5,030,654 | $9,617,426 | $24,650,203 | 55,485 |
| 2021 | $20,011,940 | $5,131,267 | $9,617,426 | $25,143,207 | 92,475 |
| 2022 | $20,412,179 | $5,233,892 | $9,617,426 | $25,646,071 | 129,465 |
| 2023 | $20,820,422 | $5,338,570 | $9,617,426 | $26,158,992 | 166,455 |
| 2024 | $21,236,831 | $5,445,341 | $9,617,426 | $26,682,172 | 203,446 |
| 2025 | $21,661,567 | $5,554,248 | $9,617,426 | $27,215,816 | 240,436 |
| 2026 | $22,094,799 | $5,665,333 | $9,617,426 | $27,760,132 | 277,426 |
| 2027 | $22,536,695 | $5,778,640 | $9,617,426 | $28,315,334 | 314,416 |
| 2028 | $22,987,429 | $5,894,212 | $9,617,426 | $28,881,641 | 351,406 |
| 2029 | $0 | $0 | $0 | $0 | 351,406 |
| 2030 | $0 | $0 | $0 | $0 | 351,406 |
| 2031 | $0 | $0 | $0 | $0 | 351,406 |
| 2032 | $0 | $0 | $0 | $0 | 351,406 |
| 2033 | $0 | $0 | $0 | $0 | 351,406 |
| 2034 | $0 | $0 | $0 | $0 | 351,406 |
| 2035 | $0 | $0 | $0 | $0 | 351,406 |
| 2036 | $0 | $0 | $0 | $0 | 351,406 |
| 2037 | $0 | $0 | $0 | $0 | 351,406 |
| 2038 | $0 | $0 | $0 | $0 | 351,406 |
| **Total** | **$200,998,837** | **$51,538,163** | **$91,365,547** | **$252,537,000** | **5,363,565** |

Source: Newport Partners, LLC

### 2.1.5 Street Lighting

Public street lighting accounts for approximately two percent of PREPA's load historically. Most of the existing lighting uses high pressure sodium lamps. Conversion to more efficient, LED technology would offer substantial savings estimated to range from 30 to 50 percent savings. The EE savings estimates are assumed to be 40 percent in these projections.

[5] To account for continued life of assets beyond the end the program we continued the savings for 10 years after the last programmed expenditure.

For this measure, a full conversion of the public street lighting to LED light bulbs is assumed to be phased in over five years. Public funding to support this measure is assumed as a key input. Energy savings from this measure are presented in Exhibit 2-6.

**Exhibit 2-6. Public Street Lighting Projections**

| | Annual MWh Savings - TOTAL |
|---|---|
| 2019 | 25,233 |
| 2020 | 50,634 |
| 2021 | 76,231 |
| 2022 | 102,056 |
| 2023 | 127,998 |
| 2024 | 128,268 |
| 2025 | 128,357 |
| 2026 | 128,186 |
| 2027 | 127,739 |
| 2028 | 126,857 |
| 2029 | 125,768 |
| 2030 | 124,863 |
| 2031 | 124,049 |
| 2032 | 123,302 |
| 2033 | 122,633 |
| 2034 | 122,048 |
| 2035 | 121,547 |
| 2036 | 121,124 |
| 2037 | 120,766 |
| 2038 | 120,603 |
| **Total** | **2,248,262** |

Source: Newport Partners, LLC

### 2.1.6 Residential Rebuilding Efficiency

Increased efficiency from rebuilding and restoration efforts following the 2017 hurricanes is expected to continue and is estimated for the IRP. As of the Puerto Rico Recovery Plan released in August 2018, an estimated 166,000 residential structures damaged or destroyed still needed to be repaired or rebuilt.[6] A detailed assessment of expected energy savings was performed by McKinsey in 2018. This assessment concluded that savings from reconstruction efforts would reduce load from air conditioning, refrigerators, lighting, water heating and other miscellaneous appliances around 30% relative to the original residences' usage prior to reconstruction. This savings level was applied to PREPA's reported average annual residential account consumption of 3,559 kWh/yr. to estimate total expected savings for the balance of reconstruction efforts. The August 2018 Puerto Rico Recovery Plan indicates that the reconstruction of the remaining damaged and destroyed residences is a

[6] http://www.p3.pr.gov/assets/pr-transformation-innovation-plan-congressional-submission-080818.pdf

priority to complete over the next two years. Based on this, much of the rebuilding is assumed to occur by the end of 2019 with the balance to occur in 2020. The projected annual savings from residential rebuilding efforts is presented in Exhibit 2-7.

**Exhibit 2-7. Residential Rebuilding Efficiency Projections**

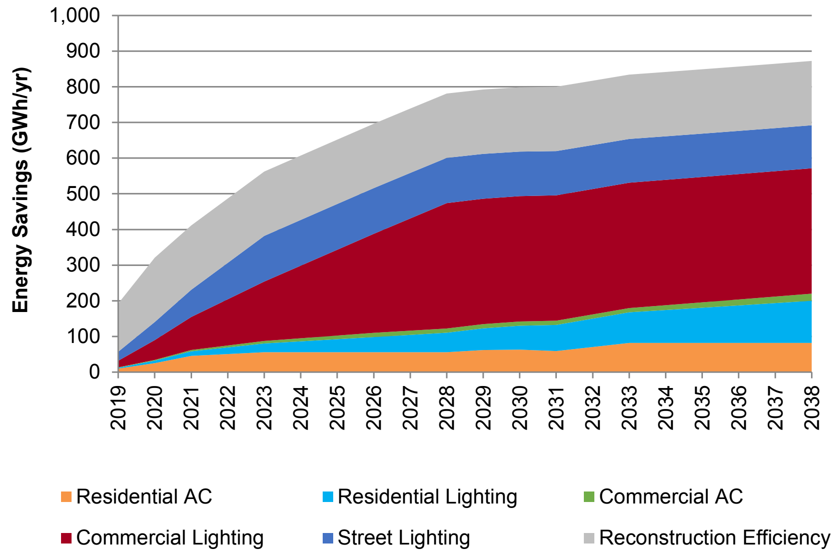
| | Annual MWh Savings - TOTAL |
|---|---|
| 2019 | 135,310 |
| 2020 | 180,413 |
| 2021 | 180,413 |
| 2022 | 180,413 |
| 2023 | 180,413 |
| 2024 | 180,413 |
| 2025 | 180,413 |
| 2026 | 180,413 |
| 2027 | 180,413 |
| 2028 | 180,413 |
| 2029 | 180,413 |
| 2030 | 180,413 |
| 2031 | 180,413 |
| 2032 | 180,413 |
| 2033 | 180,413 |
| 2034 | 180,413 |
| 2035 | 180,413 |
| 2036 | 180,413 |
| 2037 | 180,413 |
| 2038 | 180,413 |
| **Total** | **3,563,159** |

Source: PREPA, McKinsey, Government of Puerto Rico

### 2.1.7 Total Savings – Energy Efficiency

Aggregate annual energy savings from energy efficiency measures is presented in Exhibit 2-8. These projections reflect participation rates on par with that of other successful programs implemented in other areas in the U.S. and island utility settings as well as measures specific to Puerto Rico associated with hurricane restoration. Total savings projected from these measures are estimated to reach close to 900 GWh annually by the end of the study period.

**Exhibit 2-8. Annual EE Savings by Measure**




Source: Newport Partners, LLC, PREPA, Siemens

## 2.2 Demand Response

A variety of demand response measures were considered for the IRP including programmatic demand response for residential and commercial customers. A summary of demand response programs ultimately deemed appropriate to include in the IRP is presented in Exhibit 2-9.

**Exhibit 2-9 Summary of Demand Response Measures**

| DR Program | Program Description | Rationale | Key Assumptions | Approximate Cost Effectiveness Range (TRC) |
|---|---|---|---|---|
| Residential Demand Response | Load control of residential A/C systems | This measure provides for residential load management by enabling load control for residential window and mini split A/C units of participating customers via an installed communicating thermostat. Comparable programs are offered by mainland U.S. utilities in Florida, Massachusetts, Hawaii and other states. | It is assumed that roughly 85 percent of PREPA residential customers have window or split A/C and would form the base of potential participants. | 3 - 4 |
| Commercial Demand Response | Load control during anticipated peak conditions, minimum load to participate | This measure provides for commercial load management by enabling load control for commercial AC and lighting systems. Some programs have also included water heating. This measure can be implemented either automatically where the pre-designated loads are reduced under low-frequency conditions or manually by either utility or on-site operators when peak conditions are anticipated. Utility-controlled load curtailment is the most reliable implementation method. In all cases, the participant is notified in advance that loads will be shed. Most utility programs also require that participants identify a minimum of 50 kW for load curtailment. Usually, events are guaranteed to last no more than 1 hour. | While most commercial demand response programs include some very large commercial and industrial customers, for PREPA, it is assumed that participants would most likely be small and medium-sized commercial establishments – especially in initial program years. Pharmaceuticals are not assumed to participate due to the need for tightly controlled environments all hours of the day. Typical participants well-suited to such a program include hotels/motels, office buildings, non-food retail establishments, and educational facilities. | 1 - 2 |

Source: Newport Partners, LLC

Additional demand response programs considered in the development of this IRP but not ultimately included as a specific projection at this time are listed and summarized below.

- Water pumping – PREPA data indicates approximately 33 MW of water pumping load exists at 48 locations across the island. However, given that the water company is also a government owned enterprise whose role is providing water and sewage services, this program would require intergovernmental agreements, which will take time and are uncertain at this moment. As a conservative assumption, a water pumping DR measure is not included as part of this IRP.
- Standby diesel – The use of customer sited diesel generators as a means of DR for PREPA's system was also considered. The customers where these generators are sited could turn this generation on instead of shedding part of their load, resulting in an effective load reduction at the customer meter. However, for this to be implemented, short of splitting the customer system in two (one connected to PREPA and one connected with the local generation), the customer generators would require appropriate protection and controls to operate the generators synchronized with the grid. Additionally, the customers would need to enter into an interconnection agreement for them to operate in parallel with the grid. Hence, given this uncertainty, the standby diesel DR measure was not considered for the IRP at this time.

### 2.2.1 Residential Demand Response

This program sheds residential loads during peak demand periods by curtailing air conditioning operation. Comparable programs are offered by mainland U.S. utilities in Florida, Massachusetts, Hawaii and other states.

Key assumptions underlying the projected costs and peak energy savings for residential demand response include:

- On average one percent of eligible customers participate in the program;
- There is no additional cost to participants to participate;
- Utility incurs a one-time cost of $200 per customer based on reported costs for similar programs in Florida and Hawaii to install Wi-Fi monitored thermostat and set up the customer account;
- Additional administrative costs are assumed to implement and manage the program on an ongoing basis;
- On average, customers receive $100 per year in payments for peak demand reductions;
- Net peak energy load reductions per participating customer assumed to be 1.2 kW based on average power consumption for 1 ton window units and 1 ton split units.

A summary of the residential demand response program peak load savings and costs is presented in Exhibit 2-10.

**Exhibit 2-10. Residential Demand Response Projections**

| | Participant Costs | Non-Reoccurring Utility Cost | Reoccurring Utility Cost | Utility Incentive Costs | Total Costs (excluding incentives) | Annual kW Reduction: |
|---|---|---|---|---|---|---|
| 2019 | $0 | $2,275,759 | $1,820,608 | $1,137,880 | $4,096,367 | 13,655 |
| 2020 | $0 | $2,337,524 | $3,355,635 | $2,056,149 | $5,693,158 | 24,674 |
| 2021 | $0 | $2,400,964 | $4,658,969 | $2,798,785 | $7,059,933 | 33,585 |
| 2022 | $0 | $2,466,126 | $5,774,619 | $3,400,971 | $8,240,746 | 40,812 |
| 2023 | $0 | $2,533,057 | $6,738,535 | $3,890,853 | $9,271,592 | 46,690 |
| 2024 | $0 | $2,601,804 | $7,580,088 | $4,290,949 | $10,181,891 | 51,491 |
| 2025 | $0 | $2,672,417 | $8,323,285 | $4,619,274 | $10,995,702 | 55,431 |
| 2026 | $0 | $2,744,946 | $8,987,757 | $4,890,240 | $11,732,704 | 58,683 |
| 2027 | $0 | $2,819,444 | $9,589,565 | $5,115,376 | $12,409,009 | 61,385 |
| 2028 | $0 | $2,895,964 | $10,141,856 | $5,303,907 | $13,037,820 | 63,647 |
| 2029 | $0 | $2,974,560 | $10,655,403 | $5,463,214 | $13,629,963 | 65,559 |
| 2030 | $0 | $3,055,290 | $11,139,041 | $5,599,199 | $14,194,330 | 67,190 |
| 2031 | $0 | $3,138,210 | $11,600,025 | $5,716,588 | $14,738,236 | 68,599 |
| 2032 | $0 | $3,223,381 | $12,044,326 | $5,819,160 | $15,267,707 | 69,830 |
| 2033 | $0 | $3,310,864 | $12,476,861 | $5,909,938 | $15,787,725 | 70,919 |
| 2034 | $0 | $3,400,721 | $12,901,695 | $5,991,344 | $16,302,416 | 71,896 |
| 2035 | $0 | $3,493,016 | $13,322,196 | $6,065,311 | $16,815,213 | 72,784 |
| 2036 | $0 | $3,587,817 | $13,741,166 | $6,133,391 | $17,328,983 | 73,601 |
| 2037 | $0 | $3,685,190 | $14,160,943 | $6,196,823 | $17,846,134 | 74,362 |
| 2038 | $0 | $3,785,206 | $14,583,495 | $6,256,600 | $18,368,701 | 75,079 |
| **Total** | **$0** | **$59,402,261** | **$193,596,069** | **$96,655,952** | **$252,998,330** | **1,159,871** |

Source: Newport Partners, LLC

### 2.2.2 Commercial Demand Response

This program sheds commercial loads during peak demand periods by curtailing air conditioning and lighting operation. While most commercial demand response programs include some very large commercial and industrial customers, for PREPA, it is assumed that participants would most likely be small and medium-sized commercial establishments, especially in initial program years.

Key assumptions underlying the projected costs and peak energy savings for commercial demand response include:

- On average annual participation growth of 0.4 percent of eligible customers participate in the early years of the program, slowing to 0.2 percent annual increase after the first five years of the program due to saturation of interest. (Annual participation growth rate in commercial DR programs is particularly dependent upon the types and sizes of commercial establishments in the service territory as well as upon the characteristics of generating capacity and distribution.)
- No additional cost to customers to participate;

- Utility incurs a one-time cost of $400 per customer based on reported costs for similar programs in Florida and Hawaii to install Wi-Fi monitored thermostats, lighting controls, communication software and set up customer account;
- Additional administrative costs are assumed to implement and manage the program on an ongoing basis;
- On average, customers receive $3,000 per year in payments for peak demand reductions; and
- Net peak energy load reductions per participating customer are assumed to be 6 kW.

A summary of the commercial demand response program energy savings and costs is presented in Exhibit 2-11.

**Exhibit 2-11. Commercial Demand Response Projections**

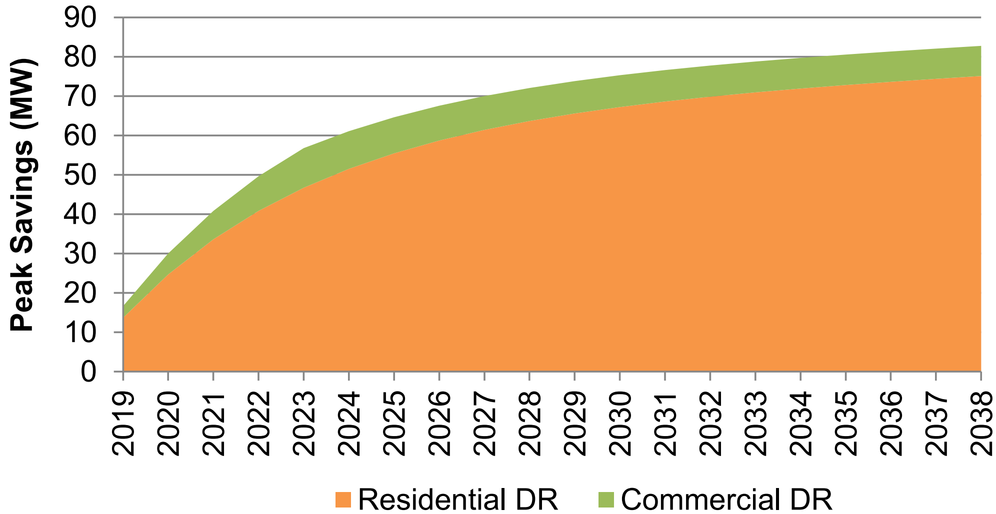
| | Participant Costs | Non-Reoccurring Utility Cost | Reoccurring Utility Cost | Utility Incentive Costs | Total Costs (excluding incentives) | Annual kW Reduction: |
|---|---|---|---|---|---|---|
| 2019 | $0 | $197,281 | $986,403 | $1,479,604 | $1,183,683 | 2,959 |
| 2020 | $0 | $201,226 | $1,811,035 | $2,663,287 | $2,012,261 | 5,327 |
| 2021 | $0 | $205,251 | $2,504,058 | $3,610,234 | $2,709,309 | 7,220 |
| 2022 | $0 | $214,165 | $3,114,138 | $4,401,783 | $3,328,304 | 8,804 |
| 2023 | $0 | $218,449 | $3,633,380 | $5,035,022 | $3,851,829 | 10,070 |
| 2024 | $0 | $111,409 | $3,521,882 | $4,784,816 | $3,633,291 | 9,570 |
| 2025 | $0 | $113,637 | $3,442,041 | $4,584,651 | $3,555,678 | 9,169 |
| 2026 | $0 | $115,910 | $3,388,254 | $4,424,519 | $3,504,164 | 8,849 |
| 2027 | $0 | $118,228 | $3,355,955 | $4,296,413 | $3,474,183 | 8,593 |
| 2028 | $0 | $120,592 | $3,341,422 | $4,193,928 | $3,462,014 | 8,388 |
| 2029 | $0 | $123,004 | $3,341,622 | $4,111,941 | $3,464,626 | 8,224 |
| 2030 | $0 | $125,464 | $3,354,086 | $4,046,351 | $3,479,550 | 8,093 |
| 2031 | $0 | $127,974 | $3,376,802 | $3,993,878 | $3,504,776 | 7,988 |
| 2032 | $0 | $130,533 | $3,408,137 | $3,951,901 | $3,538,670 | 7,904 |
| 2033 | $0 | $133,144 | $3,446,759 | $3,918,319 | $3,579,903 | 7,837 |
| 2034 | $0 | $135,807 | $3,491,589 | $3,891,453 | $3,627,396 | 7,783 |
| 2035 | $0 | $138,523 | $3,541,751 | $3,869,960 | $3,680,274 | 7,740 |
| 2036 | $0 | $141,293 | $3,596,535 | $3,852,766 | $3,737,829 | 7,706 |
| 2037 | $0 | $144,119 | $3,655,369 | $3,839,011 | $3,799,488 | 7,678 |
| 2038 | $0 | $147,002 | $3,717,789 | $3,828,007 | $3,864,790 | 7,656 |
| **Total** | **$0** | **$2,963,011** | **$64,029,006** | **$78,777,843** | **$66,992,016** | **157,556** |

Source: Newport Partners, LLC

## 2.2.3 Total Savings – Demand Response

Aggregate peak energy savings from demand response measures is presented in Exhibit 2-12. These projections reflect participation rates on par with that of other successful programs implemented in other areas in the U.S. and island utility settings.

**Exhibit 2-12. Annual Peak Energy Savings from DR Programs**




Source: Newport Partners, LLC

### 2.2.4 Overall Energy Savings from Demand-Side Resources

Regulation 9021 defines a target for the IRP to achieve two percent incremental energy savings per year for at least ten years.[7] Energy savings from new energy efficiency measures are projected to range from between 0.3 percent and 1.25 percent incremental annual savings over the first ten years of the study period, from 2019 to 2028. Demand response programs contribute additional savings to peak demand. Additional demand side savings from government end use and existing programs is expected to also contribute towards the prescribed two percent incremental energy savings goal.

On August 17th, 2018, the Puerto Rico Energy Bureau (PREB) issued an order requiring PREPA to develop additional scenarios for its IRP. Several of these considerations relate to demand side measures, considering incremental EE and DR. Specifically, the order requires the following:

- Determine of a Reference EE scenario that ramps up to 2 percent annual incremental energy savings per year;
- Determine a Low EE scenario that ramps up to 1 percent annual incremental energy savings per year; and
- Include DR where savings ramp up to 3 percent of peak load by 2025.

To meet these scenarios, Siemens developed EE and DR scenarios to meet these requirements. The original DR estimates presented above do meet the requirement set forth by the PREB and therefore no changes were made to these inputs. The reasonably

[7] Regulation 9021, Section F 3 e

achievable EE estimates detailed above in aggregate fall short of the scenario requirements for EE set forth by the PREB. To meet this requirement, additional EE scenarios were developed to meet the Baseline and the Reference EE, and the Low EE scenarios as defined by the PREB.

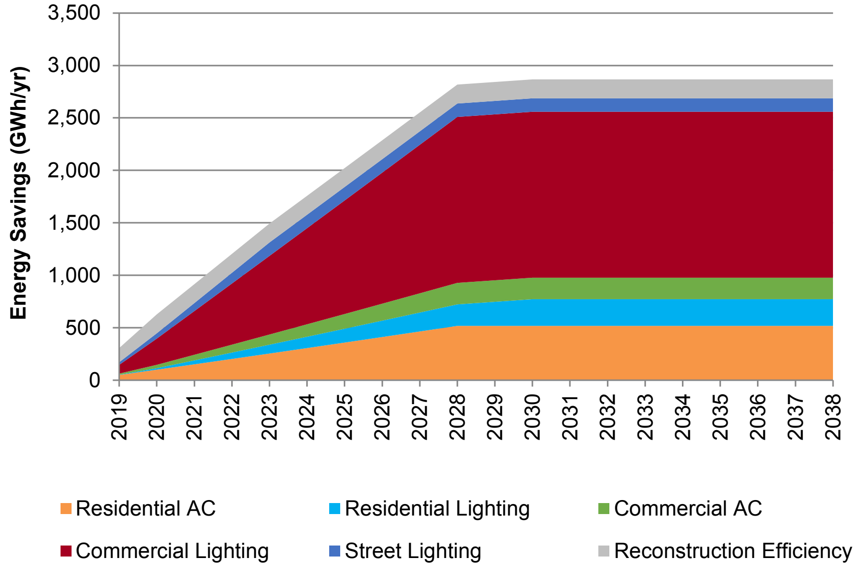
These scenarios considered the same EE measures and costs. The incremental EE was achieved by assuming greater penetration rates for the residential and commercial EE programs. It should be noted that the street lighting and reconstruction efficiency measures were assumed to reach maximum expected levels and therefore these measures remain constant. The Baseline scenario is summarized in Exhibit 2-13. and Exhibit 2-14

**Exhibit 2-13. Baseline EE Utility Cost Projections by Measure (Program Cost + Incentives)**

| | Residential AC | Residential Lighting | Commercial AC | Commercial Lighting | Total Costs |
|---|---|---|---|---|---|
| 2019 | $20,080,230 | $870,143 | $7,398,020 | $32,736,239 | $61,084,632 |
| 2020 | $20,524,103 | $4,468,794 | $14,919,340 | $65,916,358 | $105,828,596 |
| 2021 | $20,979,316 | $9,180,154 | $15,045,107 | $66,369,117 | $111,573,694 |
| 2022 | $21,446,170 | $9,429,304 | $15,173,388 | $66,830,931 | $112,879,793 |
| 2023 | $21,924,977 | $9,685,215 | $15,304,236 | $67,301,981 | $114,216,409 |
| 2024 | $22,416,056 | $9,948,072 | $15,437,700 | $67,782,453 | $115,584,281 |
| 2025 | $22,919,736 | $10,218,062 | $15,573,833 | $68,272,533 | $116,984,165 |
| 2026 | $23,436,352 | $10,495,381 | $15,712,690 | $68,772,416 | $118,416,838 |
| 2027 | $23,966,251 | $10,780,225 | $15,854,323 | $69,282,296 | $119,883,095 |
| 2028 | $24,509,789 | $11,072,801 | $15,998,789 | $69,802,373 | $121,383,752 |
| 2029 | $25,067,330 | $11,373,316 | $0 | $0 | $36,440,646 |
| 2030 | $25,639,249 | $11,681,988 | $0 | $0 | $37,321,237 |
| 2031 | $26,225,931 | $0 | $0 | $0 | $26,225,931 |
| 2032 | $26,827,771 | $0 | $0 | $0 | $26,827,771 |
| 2033 | $27,445,176 | $0 | $0 | $0 | $27,445,176 |
| 2034 | $5,573,792 | $0 | $0 | $0 | $5,573,792 |
| 2035 | $5,612,808 | $0 | $0 | $0 | $5,612,808 |
| 2036 | $5,652,098 | $0 | $0 | $0 | $5,652,098 |
| 2037 | $5,691,663 | $0 | $0 | $0 | $5,691,663 |
| 2038 | $5,731,504 | $0 | $0 | $0 | $5,731,504 |
| **Total** | **$381,670,303** | **$109,203,456** | **$146,417,426** | **$643,066,696** | **$1,280,357,881** |

Source: Siemens

**Exhibit 2-14. Baseline Annual EE Savings by Measure**



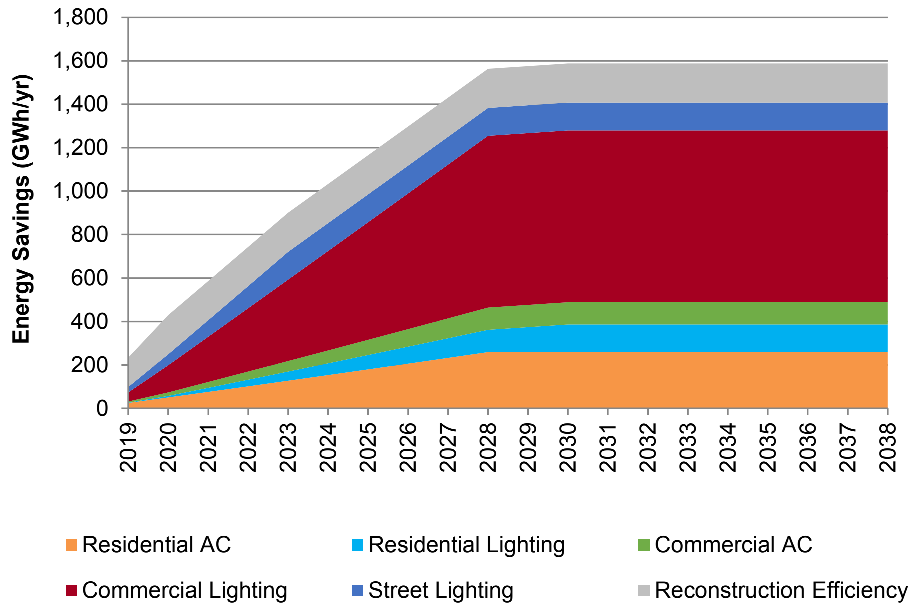

Source: Siemens

The Low EE scenario is summarized in Exhibit 2-15 and Exhibit 2-16.

**Exhibit 2-15. Low EE Utility Cost Projections by Measure (Program Cost + Incentives)**

| | Residential AC | Residential Lighting | Commercial AC | Commercial Lighting | Total Costs |
|---|---|---|---|---|---|
| 2019 | $10,040,115 | $435,072 | $3,699,010 | $16,368,119 | $30,542,316 |
| 2020 | $10,262,052 | $2,234,397 | $7,459,670 | $32,958,179 | $52,914,298 |
| 2021 | $10,489,658 | $4,590,077 | $7,522,553 | $33,184,559 | $55,786,847 |
| 2022 | $10,723,085 | $4,714,652 | $7,586,694 | $33,415,466 | $56,439,897 |
| 2023 | $10,962,489 | $4,842,608 | $7,652,118 | $33,650,991 | $57,108,205 |
| 2024 | $11,208,028 | $4,974,036 | $7,718,850 | $33,891,226 | $57,792,140 |
| 2025 | $11,459,868 | $5,109,031 | $7,786,917 | $34,136,267 | $58,492,082 |
| 2026 | $11,718,176 | $5,247,690 | $7,856,345 | $34,386,208 | $59,208,419 |
| 2027 | $11,983,126 | $5,390,113 | $7,927,161 | $34,641,148 | $59,941,548 |
| 2028 | $12,254,894 | $5,536,400 | $7,999,394 | $34,901,187 | $60,691,876 |
| 2029 | $12,533,665 | $5,686,658 | $0 | $0 | $18,220,323 |
| 2030 | $12,819,624 | $5,840,994 | $0 | $0 | $18,660,618 |
| 2031 | $13,112,965 | $0 | $0 | $0 | $13,112,965 |
| 2032 | $13,413,886 | $0 | $0 | $0 | $13,413,886 |
| 2033 | $13,722,588 | $0 | $0 | $0 | $13,722,588 |
| 2034 | $2,786,896 | $0 | $0 | $0 | $2,786,896 |
| 2035 | $2,806,404 | $0 | $0 | $0 | $2,806,404 |
| 2036 | $2,826,049 | $0 | $0 | $0 | $2,826,049 |
| 2037 | $2,845,831 | $0 | $0 | $0 | $2,845,831 |
| 2038 | $2,865,752 | $0 | $0 | $0 | $2,865,752 |
| **Total** | **$190,835,151** | **$54,601,728** | **$73,208,713** | **$321,533,348** | **$640,178,940** |

**Exhibit 2-16. Low EE Annual Savings by Measure**




### 2.2.5 Other benefits of Energy Efficiency and Demand Response

Energy Efficiency and Demand Response have additional benefits in terms of the required generation to meet the load as they have an impact on the transmission and distribution losses.

We accounted for EE by reducing the energy demand to be served, and as the load factor of the different customer types is not expected to change, the energy reduction translates directly to a peak demand reduction. Also, the effect in the distribution and transmission losses are automatically considered as these losses are added starting from the energy consumption after energy savings to get to the generation needs in the models.

For DR the net effect desired is a reduction in the generation capacity requirement and for every kW of DR there is an even greater reduction in required generation capacity due to the effect of the Transmission and Distribution losses, that combined have an impact of 10.6%, based on PREPA's information. Therefore, in the model DR values are adjusted using the following equation:

$$DR\_adjusted = DR / (1\text{-}10.6\%).$$

Section
3

# Distributed Generation (DG)

## 3.1 Current DG Penetration and Location

DG is customer installed generation that is behind the meter and owned by customers. It reduces the load served by PREPA's owned or contracted generation resources.

The DG in Puerto Rico includes DG connected to the PREPA distribution system and DG connected to the transmission system. Both categories are primarily comprised of rooftop solar. Distribution level DG is currently reported in two categories; Net-Metering and Non-Net-Metering. However, the second category largely corresponds to a temporary status as all Non-Net-Metering customers are expected to transition to net-metering given the economic advantages. Based on this understanding, these two categories are consolidated into the distribution level DG. Transmission level DG owned by commercial customers with signed interconnection agreements are assumed to be in service.

DG by its nature is embedded in the distribution system and its impact is seen as an aggregate load impact at the transmission level substations. DG is modeled as "lumped" generation within each of eight PREPA zones, reflecting distribution DG and transmission DG separately for each zone. Exhibit 3-1 summarizes the DG generation in service.

**Exhibit 3-1. Zone Level Distributed Generation in Service**

| Region | Distribution DG | Transmission DG | Total DG |
|---|---|---|---|
| | *MW* | *MW* | *MW* |
| ARECIBO | 11.91 | 4 | 15.83 |
| BAYAMON | 23.24 | 7 | 30.56 |
| CAGUAS | 22.16 | 9 | 30.74 |
| CAROLINA | 12.27 | 4 | 16.09 |
| MAYAGUEZ | 20.15 | 2 | 21.90 |
| PONCE ES | 7.51 | 4 | 11.38 |
| PONCE OE | 12.71 | 4 | 16.71 |
| S.JUAN | 20.05 | 9 | 29.54 |
| **Total** | **130.00** | **42.75** | **172.75** |

Source: PREPA, Siemens

Most of the DG is located in the north of the island, largely in parallel with the location of the load, as shown in Exhibit 3-2

**Exhibit 3-2. DG Capacity by Area**

| | Share | MW | Region |
|---|---|---|---|
| North | 71% | 122.76 | S. Juan, Bayamón, Carolina, Caguas & Arecibo |
| South | 16% | 28.09 | Ponce |
| West | 13% | 21.90 | Mayagüez |
| Total | 100% | 172.75 | |

Source: PREPA, Siemens

## 3.2 Increasing DG Penetration in Puerto Rico

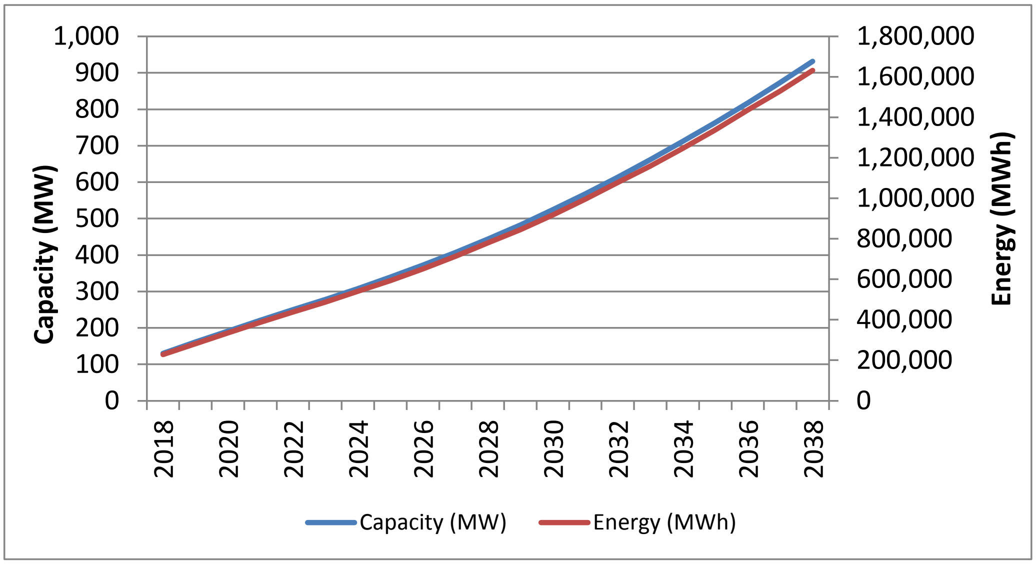
Given the economies of roof top and other forms of DG versus the cost of supply in the island, customer owned generation has experienced an explosive growth from negligible values seen as recently as 2012-2013. This trend, combined with the perception of customers of the need to gain control on their supply, are expected to result in a continued increase of DG, complemented by energy storage.

In fact as was shown in the main body of this IRP even with the reduction in cost of generation and stability that the IRP will bring, the incentives to install DG and participate in net-metering are expected to continue at values similar to those in history due to the parallel reduction in cost of roof mounted DG. Hence projections based on history are considered valid.

Exhibit 3-3 shows PREPA' projection of Distribution Level DG (consolidated Net-Metering and Not-Net-Metering). These projections were developed based on the Energy Information Administration (EIA) Annual Energy Outlook (AEO) for Residential Sector Equipment Stock and Efficiency, and Distributed Generation-Solar Photovoltaic Capacity. To develop the forecast, the Annual Energy Outlook data was first separated in monthly values, using factors determined with the Short-Term Energy Outlook from EIA for 2018 and 2019. PREPA's historical DG values were then used to create a model correlating PREPA's distribution level DG with the monthly AEO for small scale renewable generation developed as described earlier as the exogenous variable. The model showed reasonable correlation with historical data and was used to create a forecast for distribution level DG generation after June 2018 using the EIA forecast for the exogenous variable growth.

For the associated energy Siemens used a uniform capacity factor of 20% for the projection period, which may be conservative as the efficiency of panels and equipment increases.

**Exhibit 3-3. Distribution DG Capacity Projection**




Source: PREPA, Siemens

Transmission level DG projects in different stages of the interconnection process as well as larger Combined Heat and Power (CHP) projects are shown in Exhibit 3-4 and Exhibit 3-5 separately.

**Exhibit 3-4. Transmission Level DG by Stages (as of May 2018)**

| Region | Interconnected | Electric Plans Certified | Evaluated | Incomplete information |
|---|---|---|---|---|
| | *MW* | *MW* | *MW* | *MW* |
| ARECIBO | 3.93 | 0.00 | 3.02 | 0.23 |
| BAYAMON | 7.32 | 0.00 | 4.38 | 0.00 |
| CAGUAS | 8.58 | 0.00 | 3.61 | 1.76 |
| CAROLINA | 3.83 | 3.72 | 1.80 | 0.00 |
| MAYAGUEZ | 1.75 | 0.00 | 0.00 | 0.00 |
| PONCE ES | 3.87 | 0.00 | 5.99 | 0.00 |
| PONCE OE | 4.00 | 0.00 | 1.48 | 0.36 |
| S.JUAN | 9.49 | 0.10 | 14.62 | 5.56 |
| **Total** | **42.75** | **3.82** | **34.91** | **7.92** |

Source: PREPA, Siemens

**Exhibit 3-5. CHP Projects by Stages (as of May 2018)**

| Region | Electric Plans Certified | Evaluated | Incomplete information |
|---|---|---|---|
| | *MW* | *MW* | *MW* |
| ARECIBO | 0.00 | 0.00 | 18.00 |
| BAYAMON | 0.00 | 0.00 | 0.00 |
| CAGUAS | 7.87 | 9.60 | 2.50 |
| CAROLINA | 3.12 | 0.00 | 9.00 |
| MAYAGUEZ | 0.67 | 5.92 | 0.00 |
| PONCE ES | 0.00 | 0.00 | 0.00 |
| PONCE OE | 0.00 | 14.21 | 0.00 |
| S.JUAN | 0.00 | 0.00 | 0.00 |
| **Total** | **11.66** | **29.72** | **29.50** |

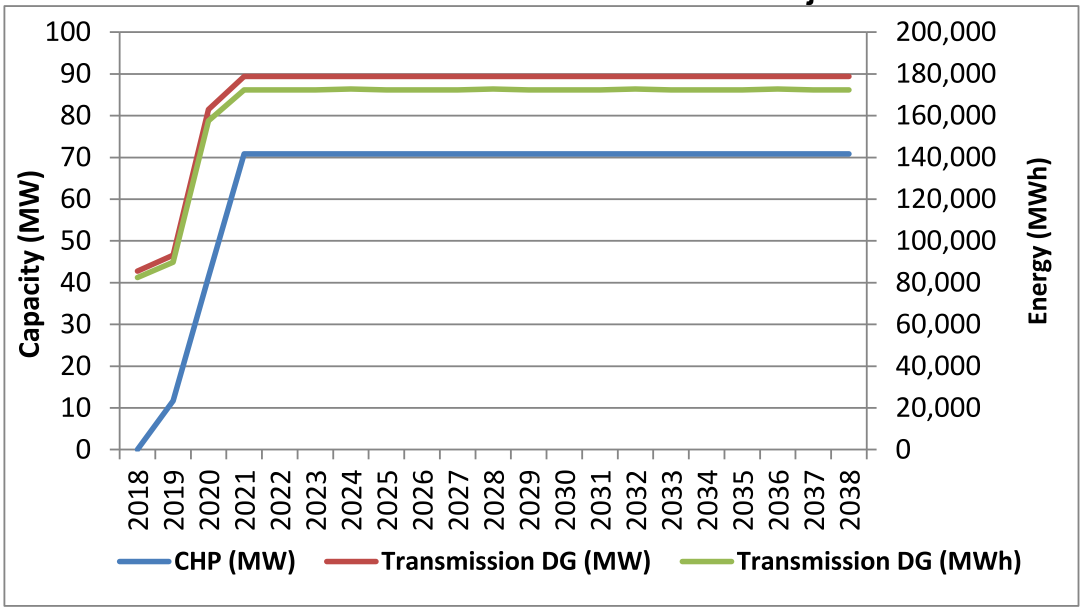
Source: PREPA, Siemens

Siemens has developed projections for transmission Level DG and Combined Heat and Power (CHP) based on the project status information provided by PREPA, assuming a one-year lag time if the project status is “electric plans Certified”, a two-year lag time to operation if the plant is under “evaluation” stage, or a three-year lag time if the project status is “incomplete information”. Exhibit 3-6 shows the projections for transmission DG and CHP, which peak by 2021. In reality, it is expected that the transmission level DG will continue. These larger scale projects are not embedded with the distribution load connected at 38 kV and above and play a role very similar to utility owned or contracted generation. Therefore, their increased penetration, beyond the one shown below are modeled as taking part in supplying the local generation needs identified by the IRP.

For transmission level DG, Siemens used a capacity factor of 22% in line with the smaller utility scale generation. For CHP their dispatch is a function of their economics, including the provision of cooling/heat or steam to satisfy the customer’s needs and hence no energy is provided at this time; however, a high capacity factor is expected.

## Distributed Generation (DG)

**Exhibit 3-6. Transmission DG and CHP Projections**




Source: PREPA, Siemens

Exhibit 3-7 shows the total DG penetration in capacity, including distribution, transmission and cogen and Exhibit 3-8 shows expected energy production from DG at the distribution and transmission level as well as the assumed capacity factors.

**Exhibit 3-7. Distribution, Transmission DG and CHP Capacity**

| Fiscal Year | Distribution DG | Transmission DG | CHP | Total DG |
|---|---|---|---|---|
| | *MW* | *MW* | *MW* | *MW* |
| 2018 | 130 | 43 | 0 | 173 |
| 2019 | 161 | 47 | 12 | 219 |
| 2020 | 191 | 81 | 41 | 314 |
| 2021 | 221 | 89 | 71 | 381 |
| 2022 | 250 | 89 | 71 | 410 |
| 2023 | 278 | 89 | 71 | 439 |
| 2024 | 308 | 89 | 71 | 468 |
| 2025 | 339 | 89 | 71 | 499 |
| 2026 | 372 | 89 | 71 | 532 |
| 2027 | 407 | 89 | 71 | 567 |
| 2028 | 444 | 89 | 71 | 604 |
| 2029 | 483 | 89 | 71 | 643 |
| 2030 | 524 | 89 | 71 | 685 |
| 2031 | 568 | 89 | 71 | 728 |
| 2032 | 614 | 89 | 71 | 774 |
| 2033 | 662 | 89 | 71 | 822 |
| 2034 | 712 | 89 | 71 | 872 |
| 2035 | 763 | 89 | 71 | 924 |
| 2036 | 817 | 89 | 71 | 978 |
| 2037 | 873 | 89 | 71 | 1,034 |
| 2038 | 932 | 89 | 71 | 1,092 |

Source: PREPA, Siemens

**Exhibit 3-8. Distribution, Transmission DG Energy**

| | Distribution DG | | Transmission DG | |
|---|---|---|---|---|
| Fiscal Year | Capacity Factor | Energy | Capacity Factor | Energy |
| | % | MWh | % | MWh |
| 2018 | 20% | 227,761 | 22% | 82,390 |
| 2019 | 20% | 282,227 | 22% | 89,752 |
| 2020 | 20% | 336,066 | 22% | 157,463 |
| 2021 | 20% | 387,352 | 22% | 172,290 |
| 2022 | 20% | 437,950 | 22% | 172,290 |
| 2023 | 20% | 487,638 | 22% | 172,290 |
| 2024 | 20% | 540,943 | 22% | 172,762 |
| 2025 | 20% | 593,870 | 22% | 172,290 |
| 2026 | 20% | 651,581 | 22% | 172,290 |
| 2027 | 20% | 712,859 | 22% | 172,290 |
| 2028 | 20% | 779,618 | 22% | 172,762 |
| 2029 | 20% | 845,834 | 22% | 172,290 |
| 2030 | 20% | 918,490 | 22% | 172,290 |
| 2031 | 20% | 995,346 | 22% | 172,290 |
| 2032 | 20% | 1,078,669 | 22% | 172,762 |
| 2033 | 20% | 1,159,406 | 22% | 172,290 |
| 2034 | 20% | 1,246,562 | 22% | 172,290 |
| 2035 | 20% | 1,337,391 | 22% | 172,290 |
| 2036 | 20% | 1,435,857 | 22% | 172,762 |
| 2037 | 20% | 1,529,923 | 22% | 172,290 |
| 2038 | 20% | 1,632,098 | 22% | 172,290 |

Source: PREPA, Siemens

## 3.3 Other Considerations on DG

By regulation, the maximum installed DG capacity allowed in the transmission and sub-transmission system is 5 MW. For the net metering program, the maximum DG capacity allowed in the distribution system is 1 MW. In addition to the limits noted above, the Puerto Rico Energy Commission (PREC) proposed regulations for future microgrid installations on the island[8]. Under the Final Microgrid Regulation, a renewable energy microgrid refers to a system of which 75 percent of its total energy output during a 12-month period is derived from renewable resources. The remaining 25 percent of energy output may be derived from fossil-fuel generation. These microgrids can result in another avenue for customer owned generation to be installed in the system.

There are a considerable number of projects proposed in transmission and distribution systems in the study and endorsement stages; so, a high penetration of renewable distributed generators projects is projected.  There are a high number of interconnection requests for DG greater than 1 MW for the sub-transmission system that do not fulfill PREPA's MTRs. Projects that do not meet the MTRs have an adverse impact on the PREPAs system. As a part of the MTRs, PREPA requires DG greater than 1 MW to include power ramp rate control (+/- 10 percent power output) or the requirement of frequency response.

Another important aspect to consider is that DG has some hidden but real costs to PREPA, as much of this generation is solar photovoltaic and does not help PREPA's needs to serve load during night time. Thus, with the net-metering arrangements customers are effectively banking the energy in PREPA's system, during the daytime, using the distribution, transmission and generation infrastructure, and taking delivery during the nighttime for free. DG changes the voltage profile of the distribution system resulting in the need for advanced voltage compensation. Finally, under current arrangements, DG does not contribute to PREPA's RPS compliance.

## 3.4 Estimated Cost of Residential Solar Photo-Voltaic (PV)

While the cost of PV is not factored directly in the formulation of the IRP's long term capacity expansion decision, but rather these resources are incorporated via the projections discussed above, it is important to gain a sense of the likely costs that the customers in Puerto Rico may experience for comparison with the cost of supply that they may receive from the utility.

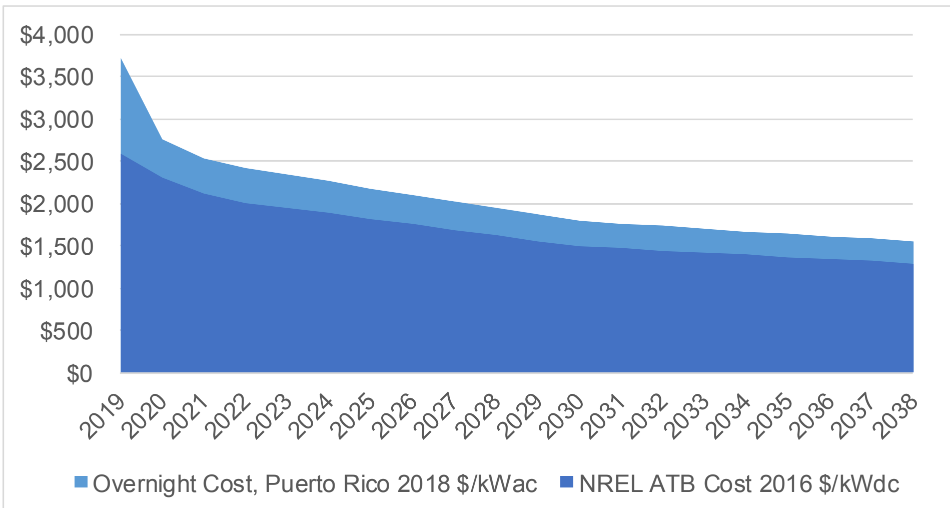
The capital costs for Residential PV are estimated using National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) forecast for residential solar. Further calculations (described below) consistent with the NREL methodology were performed to

[8] CASE NO.: CEPR-MI-2018-0001 Subject: Adoption of Proposed Regulation on Microgrid Development

obtain the total Levelized Cost of Energy (LCOE) for this option. This calculated LCOE for Residential PV was then compared to the final S4S2 rates.

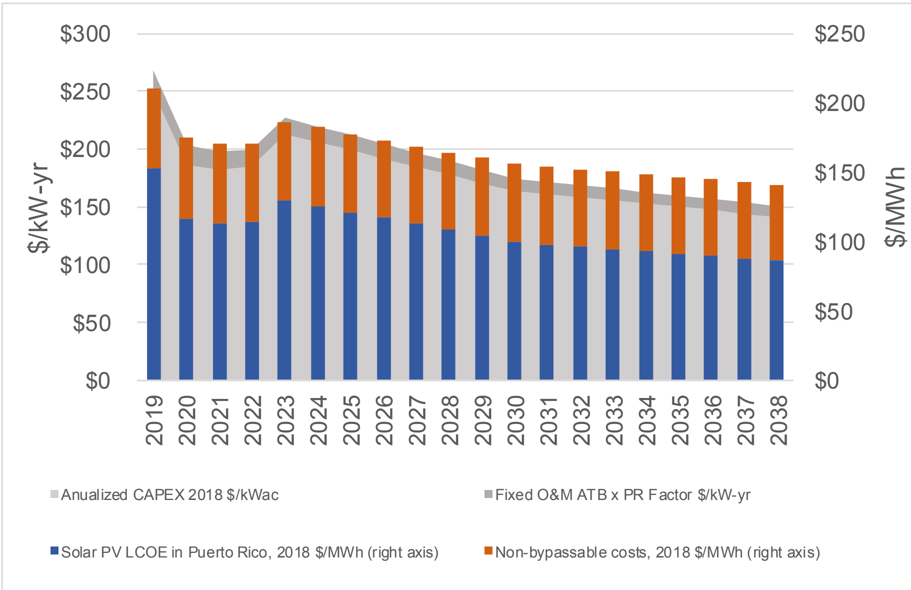
A 16% cost adder to reflect Puerto Rico specific costs was applied to NREL's capital cost ($/kWdc) estimates. Another 20% cost adder was applied to convert the capital costs to $/kWac. Since the NREL estimates were in 2016 real dollars, a conversion factor was used to escalate the cost to 2018 real dollars. Exhibit 3-9 shows the expected projection.

**Exhibit 3-9: Overnight Residential Solar PV Capital Costs**




The resulting total capital costs were annualized considering the effects of and treatment for known changes to the solar Investment Tax Credit (ITC), estimated income taxes, annual capital recovery factors, project financing factors, and construction financing factors. Annual fixed O&M estimates from NREL were adjusted for Puerto Rico and were added to the annualized capital costs. Considering a 20% capacity factor, an LCOE estimate was developed in $/MWh based on the estimated annual solar energy production. The annualized cost components ($/kW-yr.) and the resulting LCOE, with the non-bypassable rate component added, in ($/MWh) are illustrated on the left and the right axis respectively in Exhibit 3-10: Solar PV LCOE Cost Build up . Then non-bypassable rate component is the estimated PREPA debt recovery rate that will be add to all PREPA connected customers. Since most customers are likely going to remain connected to the PREPA grid, the non-bypassable debt recovery rate component was added to the PV LCOE. The detailed projections to 2038 are presented in Exhibit 3-11.

**Exhibit 3-10: Solar PV LCOE Cost Build up**



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## Exhibit 3-11: Residential Solar PV with net metering LCOE Calculations

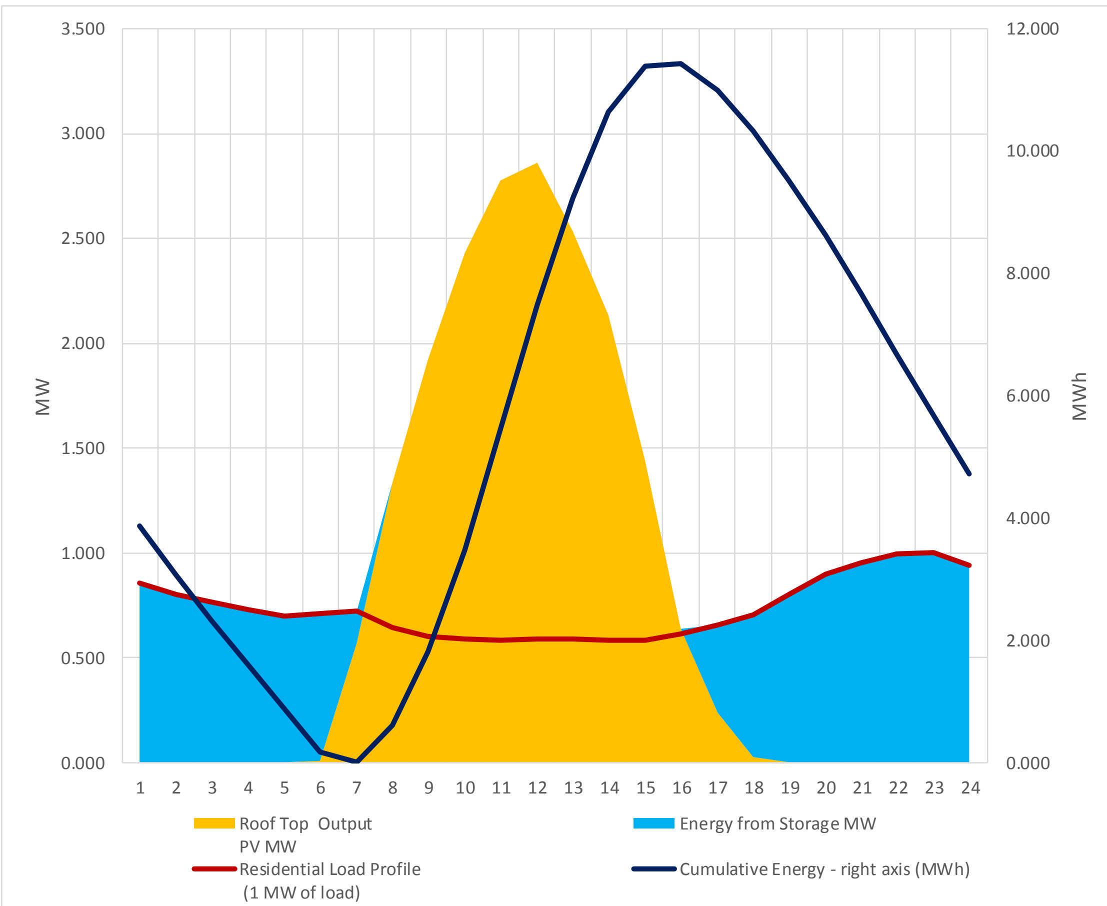
| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NREL ATB Cost 2016 $/kWdc | $2,587 | $2,306 | $2,116 | $2,011 | $1,946 | $1,882 | $1,817 | $1,752 | $1,687 | $1,623 | $1,558 | $1,493 | $1,468 | $1,443 | $1,417 | $1,392 | $1,367 | $1,341 | $1,316 | $1,291 |
| PR Factor | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% |
| AC /DC factor | 120% | 120% | 120% | 120% | 120% | 120% | 120% | 120% | 120% | 120% | 120% | 120% | 120% | 120% | 120% | 120% | 120% | 120% | 120% | 120% |
| 2016 to 2018 conversion | 104% | 104% | 104% | 104% | 104% | 104% | 104% | 104% | 104% | 104% | 104% | 104% | 104% | 104% | 104% | 104% | 104% | 104% | 104% | 104% |
| **Overnight Cost, Puerto Rico 2018 $/kWac** | **$3,727** | **$2,768** | **$2,540** | **$2,414** | **$2,337** | **$2,259** | **$2,181** | **$2,104** | **$2,026** | **$1,948** | **$1,871** | **$1,793** | **$1,763** | **$1,732** | **$1,702** | **$1,671** | **$1,641** | **$1,610** | **$1,580** | **$1,550** |
| IDC Cost Adder | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **CAPEX, Puerto Rico, 2018 $/kWac** | **$3,727** | **$2,768** | **$2,540** | **$2,414** | **$2,337** | **$2,259** | **$2,181** | **$2,104** | **$2,026** | **$1,948** | **$1,871** | **$1,793** | **$1,763** | **$1,732** | **$1,702** | **$1,671** | **$1,641** | **$1,610** | **$1,580** | **$1,550** |
| ITC | 30% | 30% | 26% | 22% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| Income Tax | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% |
| Capital Recovery Factor | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% |
| Project Financing Factor | 71% | 71% | 76% | 81% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% |
| Construction Financing Factor (assumes developer has financ | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 |
| **Anualized CAPEX 2018 $/kWac** | **$250** | **$185** | **$182** | **$185** | **$213** | **$206** | **$199** | **$192** | **$185** | **$178** | **$171** | **$163** | **$161** | **$158** | **$155** | **$152** | **$150** | **$147** | **$144** | **$141** |
| Fixed O&M ATB x PR Factor $/kW-yr | $19 | $18 | $16 | $15 | $14 | $14 | $13 | $13 | $12 | $12 | $12 | $11 | $11 | $10 | $10 | $10 | $10 | $10 | $10 | $9 |
| **All-In Cost, Puerto Rico, 2018 $/kWac-yr** | **$268** | **$203** | **$198** | **$200** | **$227** | **$220** | **$212** | **$205** | **$197** | **$190** | **$182** | **$175** | **$171** | **$168** | **$165** | **$163** | **$160** | **$157** | **$154** | **$151** |
| Capacity Factor | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 20% | 20% |
| Energy per MWac (MWh) | 1752 | 1752 | 1752 | 1752 | 1752 | 1752 | 1752 | 1752 | 1752 | 1752 | 1752 | 1752 | 1752 | 1752 | 1752 | 1752 | 1752 | 1752 | 1752 | 1752 |
| **Solar PV LCOE in Puerto Rico** | **$153** | **$116** | **$113** | **$114** | **$130** | **$125** | **$121** | **$117** | **$113** | **$108** | **$104** | **$100** | **$98** | **$96** | **$94** | **$93** | **$91** | **$89** | **$88** | **$86** |
| **Solar PV LCOE in Puerto Rico + Non-bypassable costs** | **$210** | **$174** | **$171** | **$170** | **$186** | **$182** | **$177** | **$173** | **$168** | **$164** | **$160** | **$156** | **$154** | **$152** | **$150** | **$148** | **$147** | **$145** | **$142** | **$140** |

## 3.5 Grid Defection unit.

Siemens reviewed the case where the customer decides to self-supply their entire electrical consumption and is in a positioned to go completely off the grid, if desired.

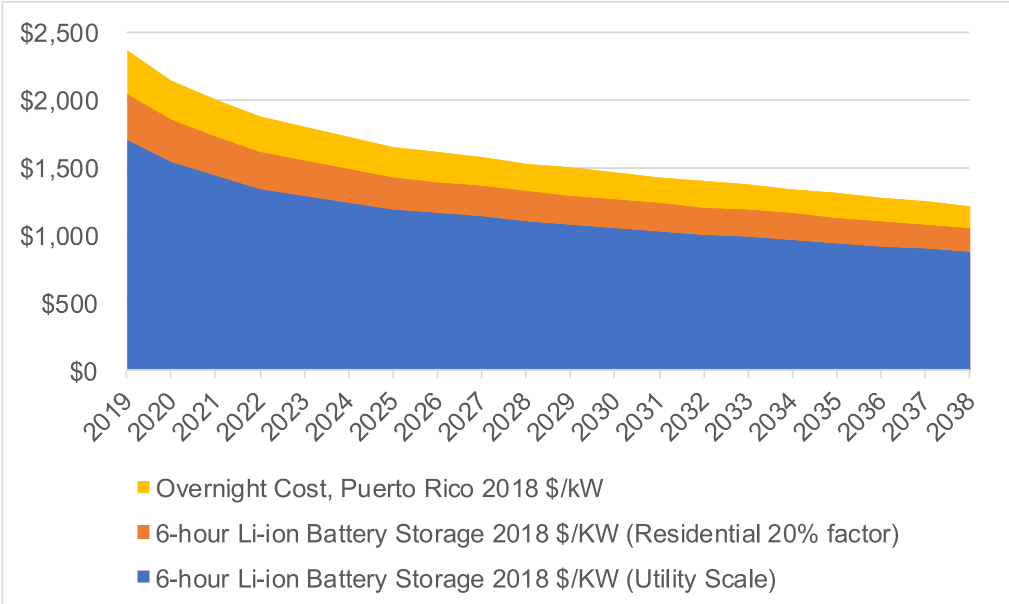
For this option we used a typical Puerto Rico residential consumption profile and determined the amount of PV and Storage capacity that would be required to self-supply. Based on the typical residential consumption profile, we determined that at least a 6 hour battery would be needed to completely self-supply. The demand and supply profile are illustrated in Exhibit 3-12.

**Exhibit 3-12: Typical Puerto Rico Residential Self Supply Example**



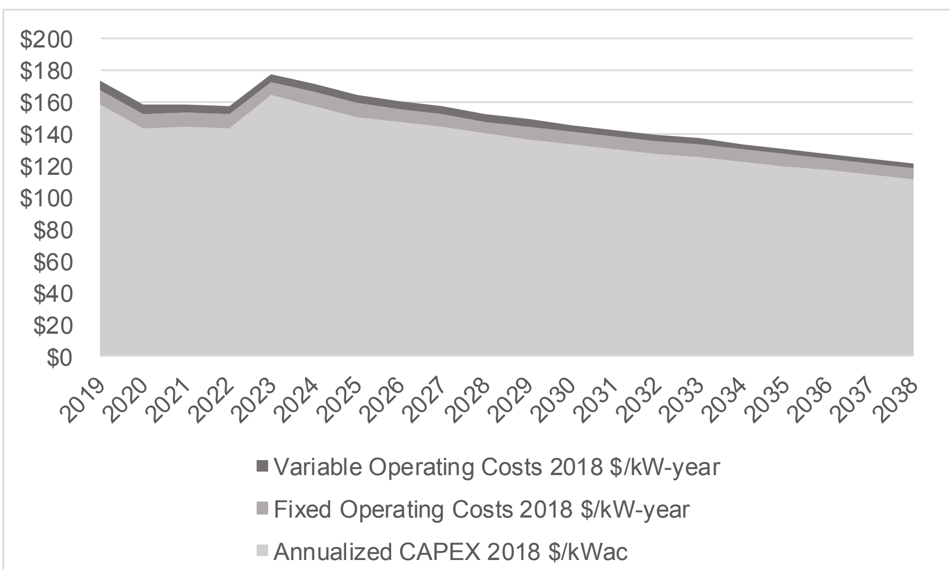

To fully develop the total costs for the grid defection alternative, we used the Solar PV LCOE already developed in the prior section. and performed a similar cost buildup based using NREL's ATB estimates for a 6-hour residential Li-ion storage system. We first developed the total overnight capital cost for the storage system in Puerto Rico as illustrated in Exhibit 3-13.

**Exhibit 3-13: Overnight Storage System Capital Costs**




We then took the total overnight capital cost for the storage system in Puerto Rico and annualized the costs using a methodology similar to that which was used for Residential PV costs. The LCOE cost build up projection presented in Exhibit 3-14 and the entire detailed cost are presented in Exhibit 3-15.

**Exhibit 3-14: Storage System LCOE Cost Build up**



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## Exhibit 3-15: Storage System LCOE Calculations

| | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6-hour Li-ion Battery Storage 2018 $/KW (Utility Scale) | $1,703 | $1,546 | $1,447 | $1,349 | $1,296 | $1,243 | $1,188 | $1,163 | $1,138 | $1,104 | $1,079 | $1,054 | $1,031 | $1,007 | $992 | $969 | $945 | $922 | $898 | $875 |
| 6-hour Li-ion Battery Storage 2018 $/KW (Residential 20% factor) | $2,043 | $1,855 | $1,736 | $1,619 | $1,555 | $1,492 | $1,426 | $1,396 | $1,366 | $1,325 | $1,295 | $1,265 | $1,237 | $1,208 | $1,191 | $1,162 | $1,134 | $1,106 | $1,078 | $1,050 |
| PR Factor | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% | 16% |
| **Overnight Cost, Puerto Rico 2018 $/kW** | **$2,370** | **$2,152** | **$2,014** | **$1,878** | **$1,804** | **$1,731** | **$1,654** | **$1,619** | **$1,585** | **$1,537** | **$1,502** | **$1,468** | **$1,435** | **$1,401** | **$1,381** | **$1,348** | **$1,315** | **$1,283** | **$1,250** | **$1,218** |
| ITC | 30% | 30% | 26% | 22% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% | 10% |
| Income Tax | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% | 32% |
| Capital Recovery Factor | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% | 9.3% |
| Project Financing Factor | 71% | 71% | 76% | 81% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% | 97% |
| Construction Financing Factor (assumes developer has financing for mult | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 | 1.02 |
| **Annualized CAPEX 2018 $/kWac** | **$159** | **$144** | **$145** | **$144** | **$164** | **$158** | **$151** | **$148** | **$144** | **$140** | **$137** | **$134** | **$131** | **$128** | **$126** | **$123** | **$120** | **$117** | **$114** | **$111** |
| Fixed Operating Costs 2018 $/kW-year | $8.96 | $8.95 | $8.81 | $8.67 | $8.54 | $8.41 | $8.40 | $8.26 | $8.12 | $7.99 | $7.86 | $7.85 | $7.71 | $7.57 | $7.44 | $7.31 | $7.30 | $7.19 | $7.08 | $6.97 |
| Variable Operating Costs 2018 $/kW-year | $5.69 | $5.66 | $5.49 | $5.33 | $5.17 | $5.02 | $4.99 | $4.82 | $4.66 | $4.51 | $4.36 | $4.32 | $4.16 | $3.99 | $3.84 | $3.69 | $3.65 | $3.60 | $3.54 | $3.49 |
| **Residential Storage annual costs $2018/kW** | **$173** | **$159** | **$159** | **$158** | **$178** | **$171** | **$164** | **$161** | **$157** | **$153** | **$149** | **$146** | **$143** | **$139** | **$137** | **$134** | **$131** | **$128** | **$125** | **$122** |

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## Exhibit 3-16: Grid Defection Total Costs

| Cost Calculations | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Yearly Load MWh (Load Factor from forecast) | 6482 | 6482 | 6482 | 6482 | 6482 | 6482 | 6482 | 6482 | 6482 | 6482 | 6482 | 6482 | 6482 | 6482 | 6482 | 6482 | 6482 | 6482 | 6482 | 6482 |
| PV MWh | 6859 | 6859 | 6859 | 6859 | 6859 | 6859 | 6859 | 6859 | 6859 | 6859 | 6859 | 6859 | 6859 | 6859 | 6859 | 6859 | 6859 | 6859 | 6859 | 6859 |
| **PV 2018 $000 /yr** | **$1,051** | **$796** | **$777** | **$782** | **$890** | **$860** | **$831** | **$801** | **$772** | **$742** | **$713** | **$683** | **$671** | **$659** | **$648** | **$636** | **$625** | **$613** | **$602** | **$590** |
| Storage (MW) | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| **Storage 2018 $000/yr** | **$347** | **$317** | **$318** | **$316** | **$356** | **$342** | **$328** | **$321** | **$314** | **$305** | **$298** | **$292** | **$285** | **$279** | **$274** | **$268** | **$262** | **$255** | **$249** | **$243** |
| **Total Costs 2018 $000/yr** | **$1,398** | **$1,113** | **$1,095** | **$1,098** | **$1,246** | **$1,203** | **$1,159** | **$1,123** | **$1,086** | **$1,048** | **$1,011** | **$975** | **$956** | **$938** | **$922** | **$904** | **$886** | **$869** | **$851** | **$833** |
| **Residential Grid Defection Cost, $/MWh** | **$216** | **$172** | **$169** | **$169** | **$192** | **$186** | **$179** | **$173** | **$168** | **$162** | **$156** | **$150** | **$147** | **$145** | **$142** | **$139** | **$137** | **$134** | **$131** | **$129** |

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Note that in the above calculations, we are assuming that the residential customer may remain grid connected but we are not adding the Non-Bypassable debt recovery charges. On the other hand, since this customer is likely to have excess PV (beyond what can be used or stored during the day) during periods where PREPA would also have excess generation, we are also not giving credit to the customer for injecting energy into the grid at these times (the marginal cost of supply is likely to be zero). The total costs incurred, which are the sum of residential PV and 6-hour storage system, are described in Exhibit 3-16.

Section
4

# Combined Heat and Power

CHP, the representative technology for cogeneration units at commercial and industrial customer locations, was modeled in two ways; using the customer load reduction projections presented earlier in this document and a resource available to PREPA to serve system load requirements, and available to the LTCE model to assess relative to other resource alternatives. Exhibit 4-1 presents the operational parameters for CHP used for modeling the resource in the LTCE.

Based on inputs from PREPA's Transformation Advisory Council (TAC), supported by information from the Department of Energy[9], an effective heat rate of 56% of the heat rate outlined in Exhibit 4-1 was assumed for the CHP in the IRP. A higher efficiency could be achieved depending on site specific conditions and engineering design configurations. This 56% heat rate equates to 47% efficiency for the electric power portion of the output and is estimated by reducing the fuel energy input by the energy that is delivered to other thermal processes; e.g. chillers. Other options to account for the efficiency is to allocate the fuel input in proportion to the useful energy provided (energy and thermal) and in this case the efficiencies can be as high as 70%[9].

**Exhibit 4-1. Small CHP (Solar Turbines Mars 100) Operational Assumptions**

| Generation Unit Type | Unit | Small CHP (Solar Turbines Mars 100) | |
|---|---|---|---|
| | | Natural Gas | Diesel |
| Max. Unit Capacity | MW | 9 | 9 |
| Min. Unit Capacity | MW | 4 | 4 |
| Min. Unit Capacity (% of Max Capacity) | % | 49% | 49% |
| Fixed O&M Expense | 2018 $/kW-year | 50.21 | 50.21 |
| Variable O&M Expense | 2018 $/MWh | 3.70 | 3.70 |
| Heat Rate at 100% Rated Capacity | MMBtu/MWh | 13.03 | 12.61 |
| Unit Capacity Degradation | % | 2.5% | 2.5% |
| Unit Heat Rate Degradation | % | 1.5% | 1.5% |
| Annual Required Maintenance Time | Hours per Year | 180 | 180 |
| Unit Forced Outage Rate | % | 0.02 | 0.02 |
| Unit Forced Outage Duration | Hours | 40 | 40 |
| Minimum Downtime | Hours | 2 | 2 |
| Minimum Runtime | Hours | 2 | 2 |

Note: Based on inputs from the DOE[9] an effective heat rate at 56% of the heat rate outlined in the above table is used, assuming higher efficiencies could be achieved depending on site specific conditions and engineering design configurations.

[9] https://www.energy.gov/sites/prod/files/2016/09/f33/CHP-Gas%20Turbine.pdf

Source: Siemens, DOE

Since the CHP is assumed to be customer owned and associated with industrial processes, no cycling (to accommodate renewable generation) is expected of these units and they were modeled as must-run units. Finally, to account for capital limitations of commercial and industrial customers, for the IRP, CHP capacity was assumed to be limited to 30% of the peak load of medium and large commercial and industrial customers.

Other options open to customer for self-supply include the use of reciprocating internal consumption engines that were discussed on the main body of the IRP.

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## *Appendix 5 – New and Existing Supply-Side Resources Supplemental Data*

Please see:

Part Four and Six of the Main Body of the IRP Filing