PREPA Ex. 1.04

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. [1]
2/12/2019

Siemens Industry, Inc.

Siemens Power Technologies International

400 State Street • P.O. Box 1058
Schenectady, New York 12301-1058 USA
Tel: +1 (518) 395-5000 • Fax: +1 (518) 346-2777
www.siemens.com/power-technologies

v16

SIEMENS

Revision History

Date	Rev.	Description
01/22/2019	0	Initial draft
02/12/2019	1	Final Draft

Contents

Legal Notice ..... **iii**

Section 1 – Introduction **1-1**

Section 2 – Energy Efficiency and Demand Response **2-1**

2.1 Energy Efficiency 2-1

2.1.1 Residential Air Conditioning 2-3

2.1.2 Residential Lighting 2-4

2.1.3 Commercial Air Conditioning 2-5

2.1.4 Commercial Lighting 2-7

2.1.5 Street Lighting 2-8

2.1.6 Residential Rebuilding Efficiency 2-9

2.1.7 Total Savings – Energy Efficiency 2-10

2.2 Demand Response 2-11

2.2.1 Residential Demand Response 2-13

2.2.2 Commercial Demand Response 2-14

2.2.3 Total Savings – Demand Response 2-15

2.2.4 Overall Energy Savings from Demand-Side Resources 2-16

2.2.5 Other benefits of Energy Efficiency and Demand Response 2-19

Section 3 – Distributed Generation (DG) **3-20**

3.1 Current DG Penetration and Location 3-20

3.2 Increasing DG Penetration in Puerto Rico 3-21

3.3 Other Considerations on DG 3-26

3.4 Estimated Cost of Residential Solar Photo-Voltaic (PV) 3-26

3.5 Grid Defection unit. 3-1

Section 4 – Combined Heat and Power **4-1**

Legal Notice

This document was prepared by Siemens Industry, Inc., Siemens Power Technologies International (Siemens PTI), solely for the benefit of Puerto Rico Electric Power Authority. Neither Siemens PTI, nor parent corporation or its or their affiliates, nor Puerto Rico Electric Power Authority, nor any person acting in their behalf (a) makes any warranty, expressed or implied, with respect to the use of any information or methods disclosed in this document; or (b) assumes any liability with respect to the use of any information or methods disclosed in this document.

Any recipient of this document, by their acceptance or use of this document, releases Siemens PTI, its parent corporation and its and their affiliates, and Puerto Rico Electric Power Authority from any liability for direct, indirect, consequential or special loss or damage whether arising in contract, warranty, express or implied, tort or otherwise, and irrespective of fault, negligence, and strict liability.

This page intentionally left blank.

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

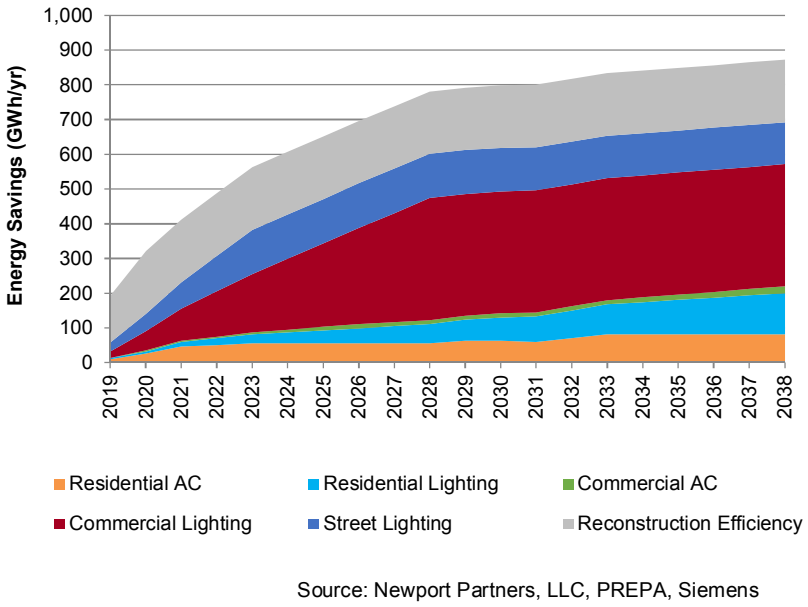
	Annual MWh Savings - TOTAL
2019	135,310
2020	180,413
2021	180,413
2022	180,413
2023	180,413
2024	180,413
2025	180,413
2026	180,413
2027	180,413
2028	180,413
2029	180,413
2030	180,413
2031	180,413
2032	180,413
2033	180,413
2034	180,413
2035	180,413
2036	180,413
2037	180,413
2038	180,413
Total	**3,563,159**

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

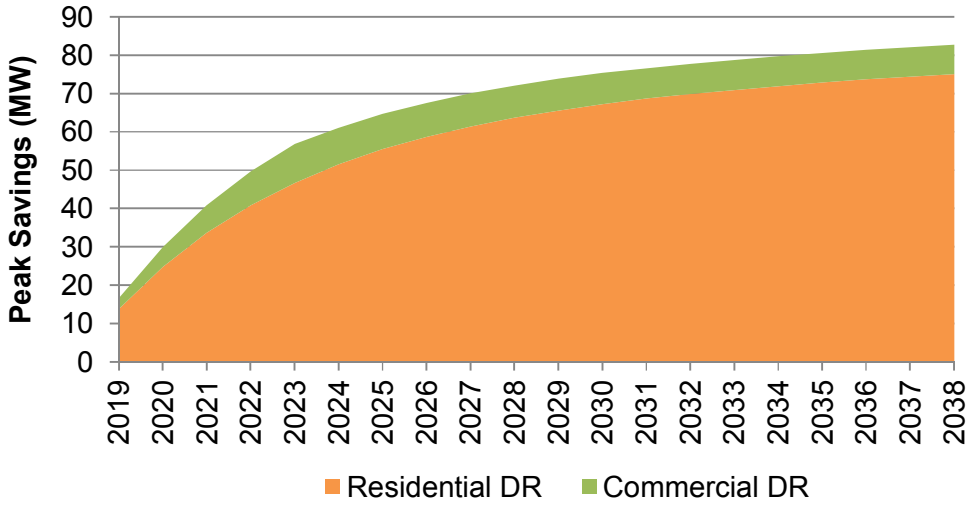
	Participant Costs	Non-Reoccurring Utility Cost	Reoccurring Utility Cost	Utility Incentive Costs	Total Costs (excluding incentives)	Annual kW Reduction:
2019	$0	$197,281	$986,403	$1,479,604	$1,183,683	2,959
2020	$0	$201,226	$1,811,035	$2,663,287	$2,012,261	5,327
2021	$0	$205,251	$2,504,058	$3,610,234	$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.

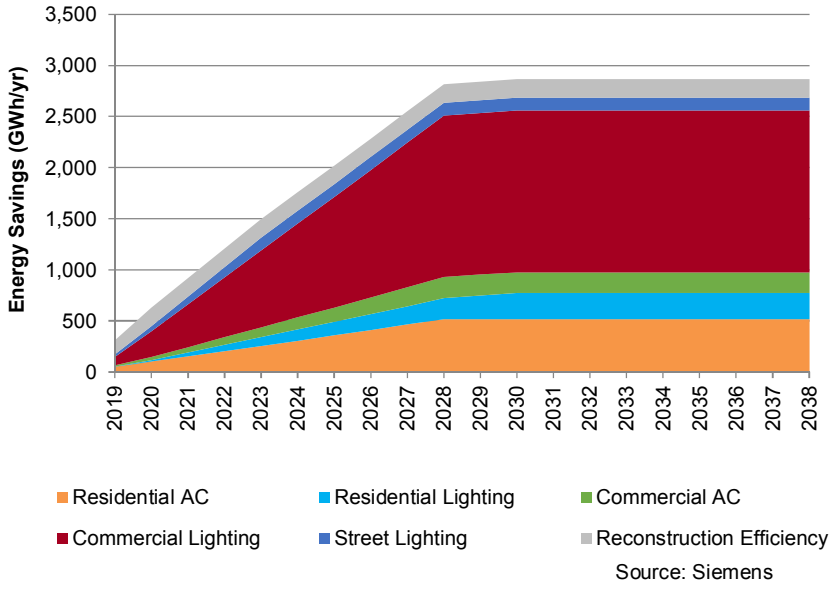
These scenarios considered the same EE measures and costs. The incremental EE was achieved by assuming greater penetration rates for the residential and commercial EE programs. It should be noted that the street lighting and reconstruction efficiency measures were assumed to reach maximum expected levels 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



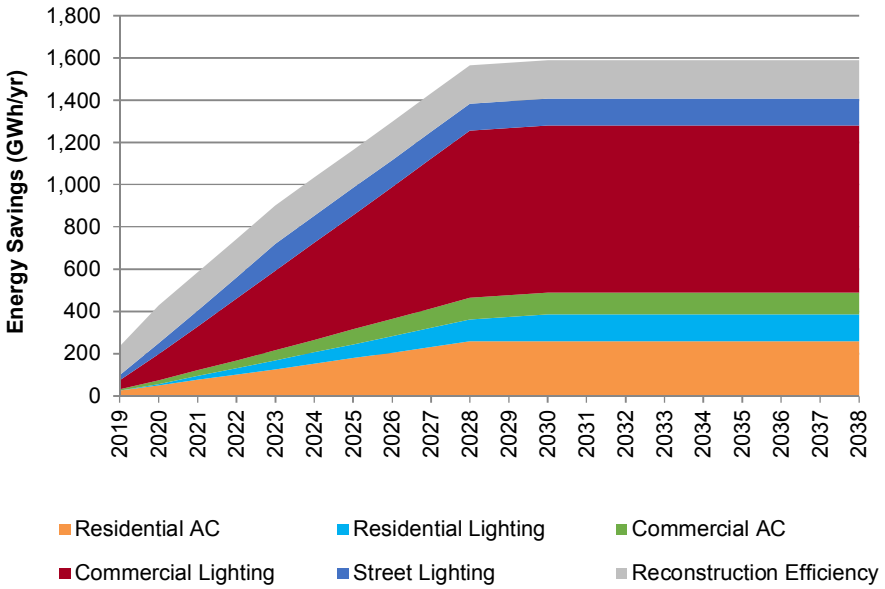
Source: Siemens

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

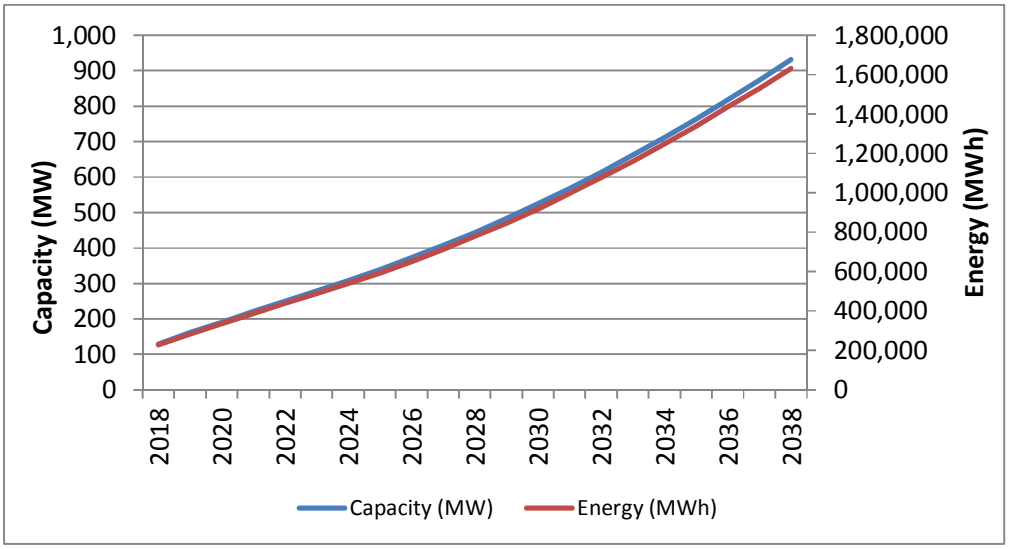
Given the economies of roof top and other forms of DG versus the cost of supply in the island, customer owned generation has experienced an explosive growth from negligible values seen as recently as 2012-2013. This trend, combined with the perception of customers of the need to gain control on their 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)

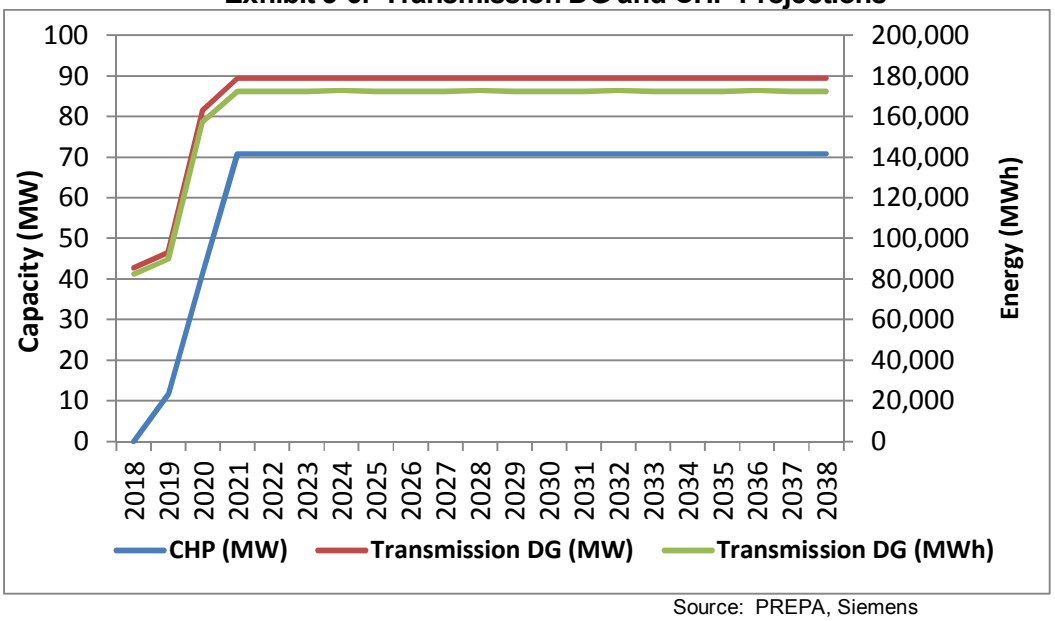
Region	Electric Plans Certified	Evaluated	Incomplete information
	MW	*MW*	*MW*
ARECIBO	0.00	0.00	18.00
BAYAMON	0.00	0.00	0.00
CAGUAS	7.87	9.60	2.50
CAROLINA	3.12	0.00	9.00
MAYAGUEZ	0.67	5.92	0.00
PONCE ES	0.00	0.00	0.00
PONCE OE	0.00	14.21	0.00
S.JUAN	0.00	0.00	0.00
Total	**11.66**	**29.72**	**29.50**

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.

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

Fiscal Year	Distribution DG		Transmission DG	
	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.

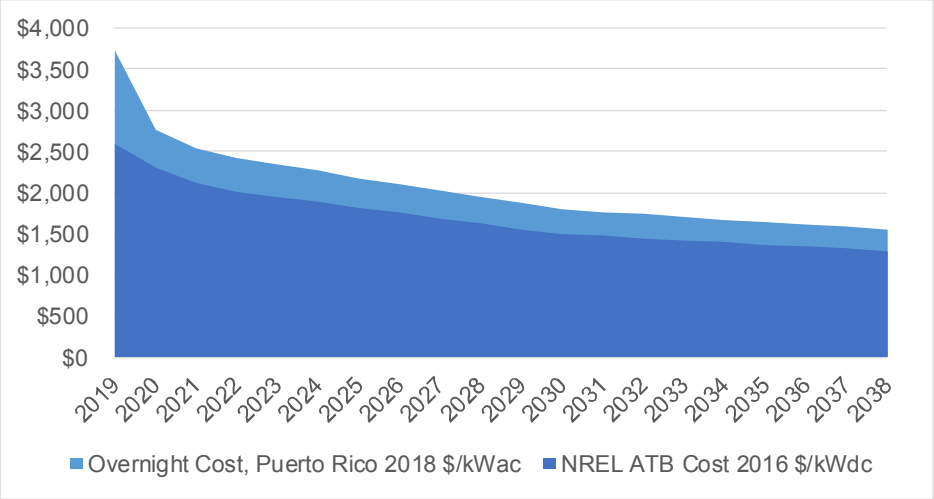
The capital costs for Residential PV are estimated using National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) forecast for residential solar. Further calculations (described below) consistent with the NREL methodology were performed to

[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

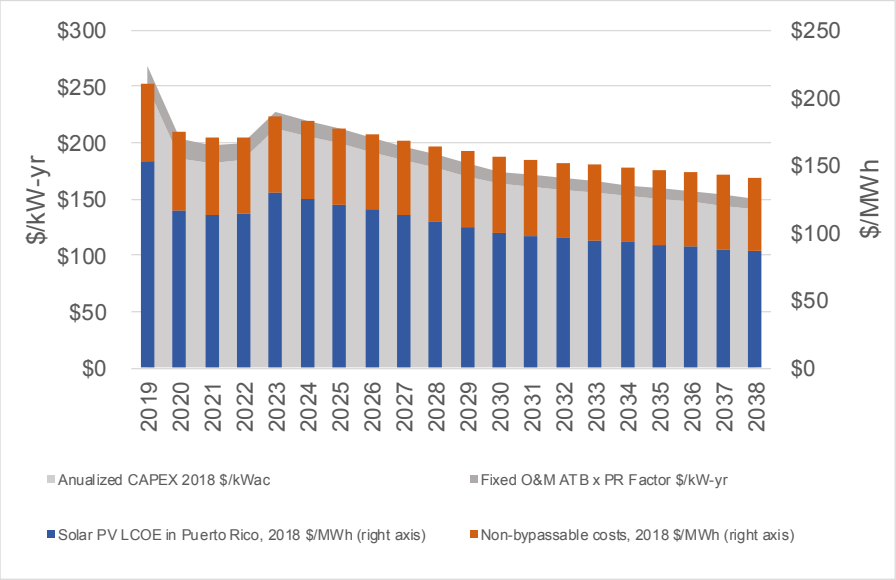


Exhibit 3-11: Residential Solar PV with net metering LCOE Calculations

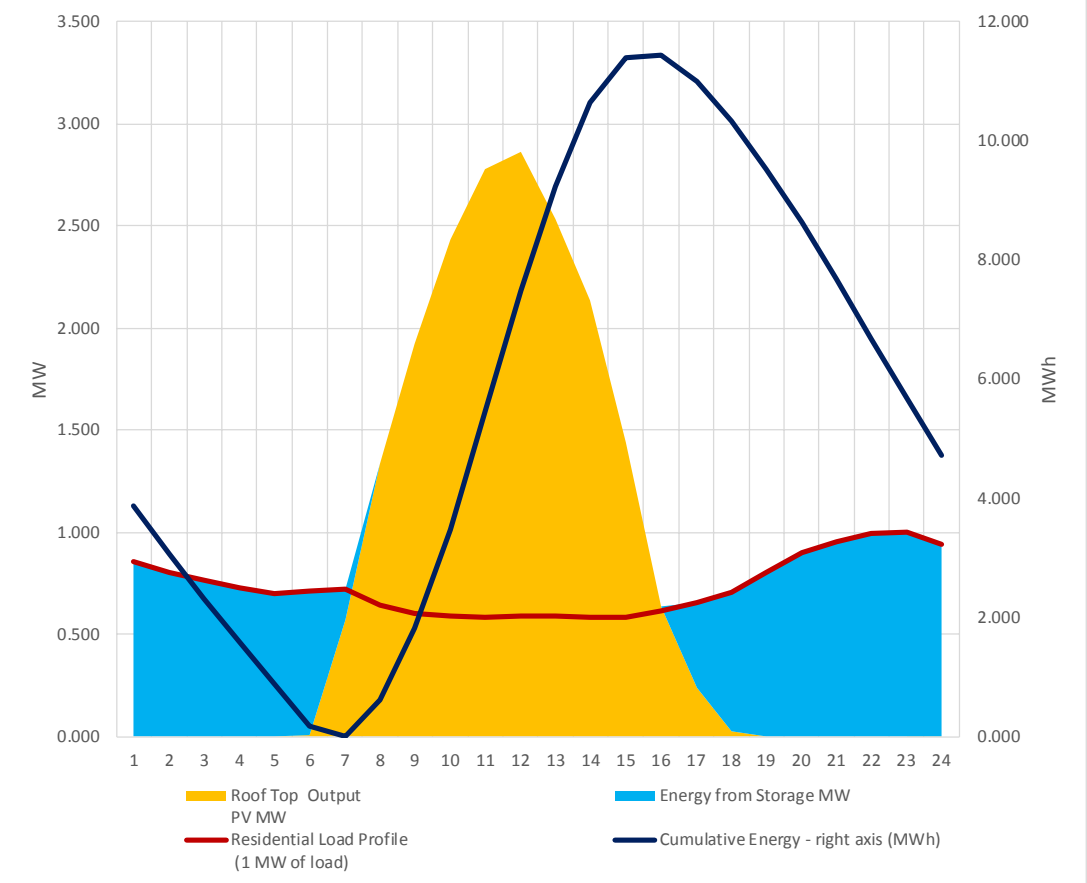
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
NREL ATB Cost 2016 $/kWdc	$2,587	$2,306	$2,116	$2,011	$1,946	$1,882	$1,817	$1,752	$1,687	$1,623	$1,558	$1,493	$1,468	$1,443	$1,417	$1,392	$1,367	$1,341	$1,316	$1,291
PR Factor	16%	16%	16%	16%	16%	16%	16%	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.

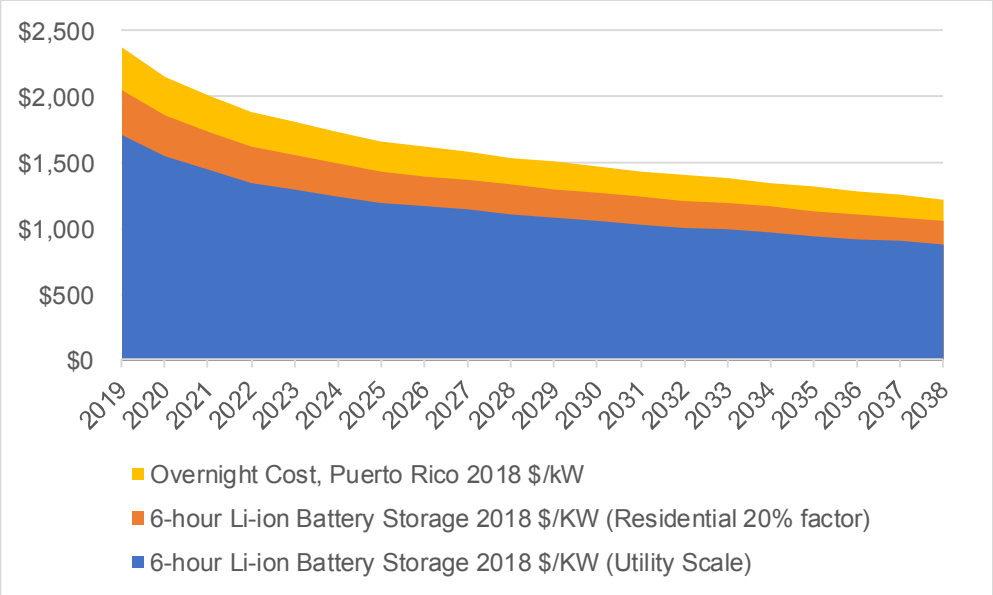
For this option we used a typical Puerto Rico residential consumption profile and determined the amount of PV and Storage capacity that would be required to self-supply. Based on the typical residential consumption profile, we determined that at least a 6 hour battery would be needed to completely self-supply. 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

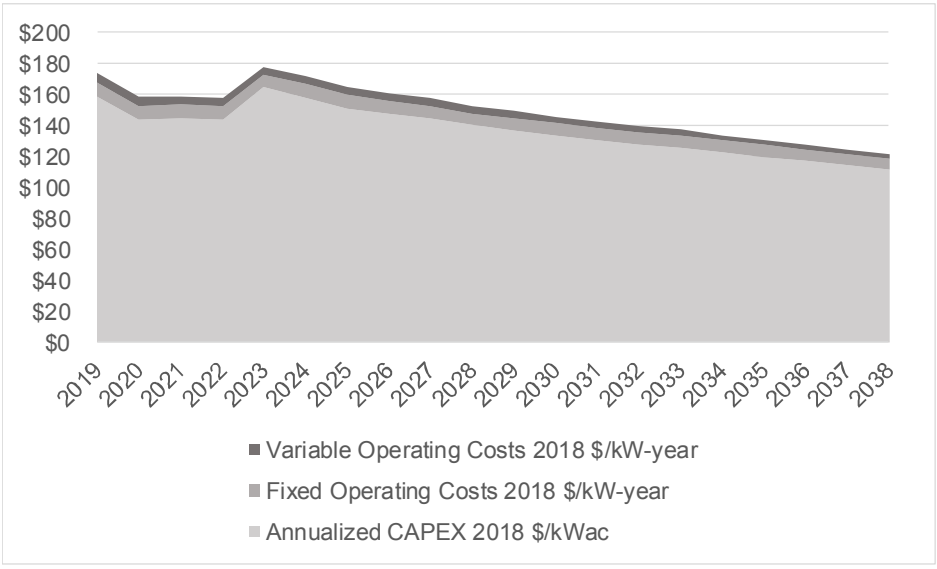


Exhibit 3-15: Storage System LCOE Calculations

	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 mul	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**

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**

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.

Siemens Industry, Inc.

Siemens Power Technologies International

400 State Street • P.O. Box 1058

Schenectady, New York 12301-1058 USA

Tel: +1 (518) 395-5000 • Fax: +1 (518) 346-2777

www.siemens.com/power-technologies