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]
6/7/2019

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v16

Revision History

Date	Rev.	Description
Error! Reference ource not found.	0	Initial draft
6/7/2019	1	Update EE section and Customer DG

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.[1] 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 meet electricity requirements over the study period.

To reasonably project EE and DR for the IRP, first the Siemens team developed a list of prospective energy-efficiency measures based on effective programs implemented in similar climates and island settings that would yield measurable savings. PREPA reviewed this list and filtered down the programs to a subset which were deemed most appropriate for PREPA customers. These programs and associated measures were then assessed and characterized to project estimates of the program impacts based on participation rates, energy savings, and program costs.

Subsequently, the Puerto Rican Energy Bureau (PREB) ordered PREPA to, "…model EE with gains of two percent (2%) per year, based on the energy sales of that year…for 18 years." Further the Order states that EE implementation should be modeled to begin in 2020 and extend through 2037.[2] The following sections describe the details of the revised estimated benefits and associated costs from those demand-side measures in accordance with the Order. To keep this presentation consistent with the larger IRP forecast, however, all program projections are presented for an additional year, from 2020 through 2038.

2.1 Energy Efficiency

The initial list of prospective energy efficiency programs included residential and commercial lighting, residential and commercial air conditioning, efficient refrigerator rebates, low income

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[1] 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.

[2] Resolution and Order, Case No. CEPR-AP-2018-0001. "REVIEW OF THE PUERTO RICO ELECTRIC POWER AUTHORITY INTEGRATED RESOURCE PLAN." Page 4.

weatherization measures, residential ceiling insulation, residential solar water heaters, and advanced residential new construction building codes. This broad list was presented to PREPA and EPPO to further assess the feasibility and potential magnitude of energy savings, including WAP and LIHEAP. The refined list of energy efficiency programs dropped additional low income weatherization measures, residential ceiling insulation, residential solar water heaters, and advanced residential new construction building codes. Exhibit 2-1 presents the programs that were determined to be the most practical and likely to result in the greatest energy savings. Detailed projections of the savings from these programs were then developed for inclusion in the initial load forecast of the IRP.

The ranges of 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. To estimate the value of energy saved, Siemens used data for 2019 residential (22 cents/kwh), commercial (22 cents/kwh) and industrial (21 cents/kwh) electricity rates from the Puerto Rico Territory Energy Profile of the U.S. Energy Information Administration. To project rates through 2038, Siemens developed growth rates for all three rate classes to match the transition charges as settled between PREPA and the Puerto Rican Financial Oversight Management Board (FOMB).[3] Electricity rates in 2038, therefore, are estimated to be over four cents more per kwh than in 2021 in nominal terms.

Many mature energy efficiency and demand response programs in the continental United States are comparable to those modeled in this section. They have large numbers of participants, an established vendor network supporting the programs, and are part of a larger portfolio of energy efficiency and demand response programs. In ramping up these programs in Puerto Rico, actual savings may lag the two percent of sales target as the associated markets for these technologies adjust to the program opportunities. Additionally, reliable native saturation data on existing end-uses is not available and reliance on secondary data from other jurisdictions in many cases will not properly represent Puerto Rico’s unique climatological, demographic and firmographic characteristics. Therefore, actual program performance metrics may also vary from these projections as well, including TRC values that may be outside of the estimated range.

[3] FOMB – PREPA RSA – 20190503, Exhibit C, Page 2.

Exhibit 2-1. Summary Energy Efficiency Measures

EE Program	Program Description	Rationale	Key Assumptions	Est. Cost Effectiveness Range (TRC[4])
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. Expected useful life is assumed at 10 years and savings are retired as the technology stock turns over.	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 average 10% annually where participants are using incandescent lamps as a baseline	3 - 5
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.	2 - 3
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

[4] 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 9%

Residential Rebuilding Efficiency	Rebuilding Hurricane homes with higher standards for 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 and built to current codes and standards.	n/a

Source: Newport Partners, LLC, PREPA

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:

- On average ten percent of eligible households participate annually;
- Average existing saturation of residential air conditioners is assumed to be 1.5 units per household, and participation never reaches saturation in the program planning horizon.
- 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 annual energy savings are retired as the air conditioner stock turns over..

The TRC of this program was calculated to be 4.3 assuming a Weighted Average Cost of Capital (WACC) of 9% on a dollar per kwh basis, the program was delivering energy savings at under four cents per kwh by 2038. A summary of the residential air conditioning program energy savings and program costs is presented in Exhibit 2-2.

Exhibit 2-2. Residential Air Conditioning Projections

	Participant Costs (nominal$)	Utility Program Costs (nominal$)	Utility Incentive Costs (nominal$)	Total Costs (excluding incentives) (nominal$)	Total Annual Savings (MWh)	Total Energy Savings (nominal$)
2020	$3,093,781	$15,468,906	$5,055,198	$18,562,687	50,552	$12,461,063
2021	$3,177,746	$15,888,732	$5,090,584	$19,066,478	101,458	$25,073,272
2022	$3,263,990	$16,319,952	$5,126,218	$19,583,942	152,720	$37,840,073
2023	$3,352,575	$16,762,875	$5,162,102	$20,115,450	204,341	$50,765,022
2024	$3,443,564	$17,217,820	$5,198,237	$20,661,384	256,323	$63,851,780
2025	$3,537,022	$17,685,111	$5,234,624	$21,222,134	308,670	$77,104,124
2026	$3,633,017	$18,165,085	$5,271,267	$21,798,102	361,382	$90,525,945
2027	$3,731,617	$18,658,086	$5,308,166	$22,389,703	414,464	$104,121,259
2028	$3,832,893	$19,164,466	$5,345,323	$22,997,359	467,917	$117,894,201
2029	$3,936,918	$19,684,590	$5,382,740	$23,621,508	521,745	$131,849,038
2030	$4,043,766	$20,218,830	$5,420,419	$24,262,596	575,949	$145,990,168
2031	$4,153,514	$20,767,569	$5,458,362	$24,921,082	630,532	$160,322,126
2032	$4,266,240	$21,331,200	$5,496,571	$25,597,441	685,498	$174,849,589
2033	$4,382,026	$21,910,129	$5,535,047	$26,292,155	740,849	$189,577,377
2034	$4,500,954	$22,504,770	$5,573,792	$27,005,724	796,586	$204,510,465
2035	$4,623,110	$23,115,550	$5,612,808	$27,738,659	802,163	$206,632,102
2036	$4,748,581	$23,742,906	$5,652,098	$28,491,487	807,778	$208,789,056
2037	$4,877,458	$24,387,288	$5,691,663	$29,264,746	813,432	$210,982,182
2038	$4,975,007	$24,875,034	$5,691,663	$29,850,041	818,728	$213,108,652
Total	**$75,573,780**	**$377,868,898**	**$102,306,880**	**$453,442,677**	**9,511,086**	**$2,426,247,492**

Source: Newport Partners, LLC and Siemens

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 is steady at ten percent per year;
- There is no additional cost to participants;
- Additional administrative costs are assumed to implement the program;
- The effective useful life exceeds the 19 year planning horizon for LED bulbs operating at two hours per day; and

- Annual household energy savings assumed to be 172 kWh based on the assumed five replacement bulbs operating for two hours per day and replacing incandescent bulbs.

The TRC of this program was calculated to be 4.3 using a WACC of 9%. By 2038, the program is estimated to deliver energy savings at a little over three cents per 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$)	Total Annual Savings (MWh)	Total Energy Savings (nominal$)
2020	$0	$8,937,588	$0	$8,937,588	23,126	$5,700,520
2021	$0	$9,180,154	$0	$9,180,154	46,414	$11,470,184
2022	$0	$9,429,304	$0	$9,429,304	69,864	$17,310,569
2023	$0	$9,685,215	$0	$9,685,215	93,479	$23,223,301
2024	$0	$9,948,072	$0	$9,948,072	117,259	$29,210,055
2025	$0	$10,218,062	$0	$10,218,062	141,206	$35,272,560
2026	$0	$10,495,381	$0	$10,495,381	165,320	$41,412,595
2027	$0	$10,780,225	$0	$10,780,225	189,603	$47,631,996
2028	$0	$11,072,801	$0	$11,072,801	214,056	$53,932,657
2029	$0	$11,373,316	$0	$11,373,316	238,681	$60,316,529
2030	$0	$11,681,988	$0	$11,681,988	263,477	$66,785,623
2031	$0	$11,999,037	$0	$11,999,037	288,447	$73,342,015
2032	$0	$12,324,691	$0	$12,324,691	313,592	$79,987,843
2033	$0	$12,659,183	$0	$12,659,183	338,913	$86,725,315
2034	$0	$13,002,754	$0	$13,002,754	364,412	$93,556,703
2035	$0	$13,355,648	$0	$13,355,648	390,088	$100,484,354
2036	$0	$13,718,121	$0	$13,718,121	415,945	$107,510,687
2037	$0	$14,090,430	$0	$14,090,430	441,982	$114,638,196
2038	$0	$14,472,845	$0	$14,472,845	468,202	$121,869,454
Total	**$0**	**$218,424,817**	**$0**	**$218,424,817**	**4,584,069**	**$1,170,381,157**

Source: Newport Partners, LLC and Siemens

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 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 ten percent of eligible commercial customers participate annually;
- Average existing saturation of commercial air conditioner units is assumed to be 1.5 units per participant, and participation never reaches saturation in the program planning horizon.
- 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 20 year unit life, which exceeds the 19 year program planning horizon.
-

The TRC of this program was calculated to be 1.5at a WACC of 9%. By 2038, the program is estimated to deliver energy savings at a little over four cents per kwh. A summary of the commercial air conditioning program energy savings and program costs is presented in Exhibit 2-4.

Exhibit 2-4. Commercial Air Conditioning Projections

	Participant Costs	Utility Program Costs (nominal$)	Utility Incentive Costs (nominal$)	Total Costs (excluding incentives) (nominal$)	Total Annual Savings (MWh)	Total Energy Savings (nominal$)
2020	$18,864,951	$6,288,317	$8,631,023	$25,153,268	21,578	$5,426,756
2021	$19,242,250	$6,414,083	$8,631,023	$25,656,333	43,155	$10,880,700
2022	$19,627,095	$6,542,365	$8,631,023	$26,169,460	64,733	$16,362,749
2023	$20,019,637	$6,673,212	$8,631,023	$26,692,849	86,310	$21,873,848
2024	$20,420,030	$6,806,677	$8,631,023	$27,226,706	107,888	$27,414,971
2025	$20,828,430	$6,942,810	$8,631,023	$27,771,240	129,465	$32,987,121
2026	$21,244,999	$7,081,666	$8,631,023	$28,326,665	151,043	$38,591,329
2027	$21,669,899	$7,223,300	$8,631,023	$28,893,198	172,620	$44,228,659
2028	$22,103,297	$7,367,766	$8,631,023	$29,471,062	194,198	$49,900,206
2029	$22,545,363	$7,515,121	$8,631,023	$30,060,484	215,776	$55,607,097
2030	$22,996,270	$7,665,423	$8,631,023	$30,661,693	237,353	$61,350,493
2031	$23,456,195	$7,818,732	$8,631,023	$31,274,927	258,931	$67,131,589
2032	$23,925,319	$7,975,106	$8,631,023	$31,900,426	280,508	$72,951,614
2033	$24,403,826	$8,134,609	$8,631,023	$32,538,434	302,086	$78,811,837
2034	$24,891,902	$8,297,301	$8,631,023	$33,189,203	323,663	$84,713,560
2035	$25,389,740	$8,463,247	$8,631,023	$33,852,987	345,241	$90,658,125
2036	$25,897,535	$8,632,512	$8,631,023	$34,530,047	366,818	$96,646,915
2037	$26,415,486	$8,805,162	$8,631,023	$35,220,648	388,396	$102,681,352
2038	$26,943,795	$8,981,265	$8,631,023	$35,925,061	409,974	$108,762,899
Total	**$430,886,019**	**$143,628,673**	**$163,989,443**	**$574,514,692**	**4,099,736**	**$1,066,981,820**

Source: Newport Partners, LLC and Siemens

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 one percent of eligible customers participate in the program;
- 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
- The effective useful life exceeds the 19 year planning horizon for LED bulbs operating at eight hours per day; 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 2.6 at a WACC of 9% By 2038, the program is estimated to deliver energy savings at a little over two cents per 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$)	Total Annual Savings (MWh)	Total Energy Savings (nominal$)
2020	$88,287,971	$22,637,941	$43,278,417	$110,925,912	166,455	$41,863,546
2021	$90,053,730	$23,090,700	$43,278,417	$113,144,430	332,911	$83,936,825
2022	$91,854,805	$23,552,514	$43,278,417	$115,407,319	499,366	$126,226,917
2023	$93,691,901	$24,023,564	$43,278,417	$117,715,465	665,822	$168,741,112
2024	$95,565,739	$24,504,036	$43,278,417	$120,069,774	832,277	$211,486,920
2025	$97,477,054	$24,994,116	$43,278,417	$122,471,170	998,733	$254,472,074
2026	$99,426,595	$25,493,999	$43,278,417	$124,920,593	1,165,188	$297,704,538
2027	$101,415,127	$26,003,879	$43,278,417	$127,419,005	1,331,644	$341,192,515
2028	$103,443,429	$26,523,956	$43,278,417	$129,967,385	1,498,099	$384,944,449
2029	$105,512,298	$27,054,435	$43,278,417	$132,566,733	1,664,555	$428,969,037
2030	$107,622,544	$27,595,524	$43,278,417	$135,218,068	1,831,010	$473,275,233
2031	$109,774,994	$28,147,434	$43,278,417	$137,922,429	1,997,465	$517,872,256
2032	$111,970,494	$28,710,383	$43,278,417	$140,680,878	2,163,921	$562,769,596
2033	$114,209,904	$29,284,591	$43,278,417	$143,494,495	2,330,376	$607,977,026
2034	$116,494,102	$29,870,283	$43,278,417	$146,364,385	2,496,832	$653,504,603
2035	$118,823,984	$30,467,688	$43,278,417	$149,291,673	2,663,287	$699,362,681
2036	$121,200,464	$31,077,042	$43,278,417	$152,277,506	2,829,743	$745,561,919
2037	$123,624,473	$31,698,583	$43,278,417	$155,323,056	2,996,198	$792,113,288
2038	$126,096,963	$32,332,555	$43,278,417	$158,429,517	3,162,654	$839,028,078
Total	$2,016,546,570	$517,063,223	$822,289,923	$2,533,609,793	31,626,536	**$8,231,002,613**

Source: Newport Partners, LLC and Siemens

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 achieve up to 65%.[5]

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.

[5] Northeast Energy Efficiency Partnerships, "LED Street Lighting Assessment and Strategies for the Northeast and Mid-Atlantic." January, 2015.

Exhibit 2-6. Public Street Lighting Projections

	Total Annual Savings (MWh)	Total Energy Savings (nominal$)
2020	41,140	$9,437,512
2021	82,583	$18,996,636
2022	124,381	$28,691,403
2023	166,398	$38,493,261
2024	208,436	$48,358,515
2025	208,580	$48,535,575
2026	208,303	$48,617,723
2027	208,303	$48,767,697
2028	208,303	$48,921,046
2029	208,303	$49,077,845
2030	208,303	$49,238,171
2031	208,303	$49,402,105
2032	208,303	$49,569,728
2033	208,303	$49,741,122
2034	208,303	$49,916,372
2035	208,303	$50,095,566
2036	208,303	$50,278,791
2037	208,303	$50,466,139
2038	208,303	$50,657,703
Total	**3,539,456**	**837,262,911**

Source: Newport Partners, LLC and Siemens

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 standards upgrades to 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 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.

[6] http://www.p3.pr.gov/assets/pr-transformation-innovation-plan-congressional-submission-080818.pdf

Exhibit 2-7. Residential Rebuilding Efficiency Projections

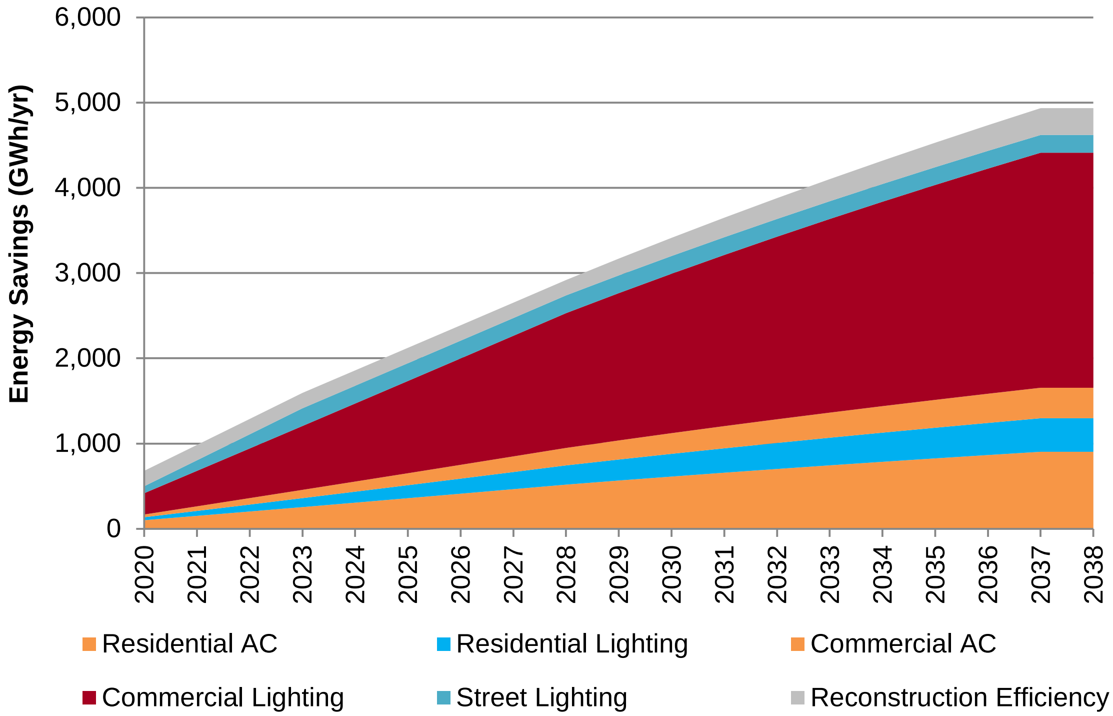
	Total Annual Savings (MWh)	Total Energy Savings (nominal$)
2020	180,413	$44,471,829
2021	180,413	$44,585,489
2022	180,413	$44,701,707
2023	180,413	$44,820,539
2024	180,413	$44,942,046
2025	180,413	$45,066,286
2026	180,413	$45,193,321
2027	180,413	$45,323,215
2028	180,413	$45,456,032
2029	180,413	$45,591,836
2030	180,413	$45,730,697
2031	180,413	$45,872,682
2032	180,413	$46,017,861
2033	180,413	$46,166,307
2034	180,413	$46,318,093
2035	180,413	$46,473,294
2036	180,413	$46,631,987
2037	180,413	$46,794,251
2038	180,413	$46,960,166
Total	3,427,849	$867,117,638

Source: PREPA, McKinsey, Government of Puerto Rico, Newport Partners, LLC and Siemens

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 programs specific to Puerto Rico associated with hurricane restoration. On average, annual savings rates represent approximately 2.15% of annual energy sales over the 2020 to 2038 program planning horizon. Total savings projected from these programs are estimated to exceed 5,000 GWh annually by the end of the study period.

Exhibit 2-8. Annual Energy Efficiency Savings by Program



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.	4 - 5
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.	2 – 3

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:
2020	$0	$2,337,524	$1,870,019	$1,145,845	$4,207,542	13,750
2021	$0	$2,400,964	$3,446,706	$2,070,542	$5,847,670	24,846
2022	$0	$2,466,126	$4,785,413	$2,818,376	$7,251,539	33,821
2023	$0	$2,533,057	$5,931,343	$3,424,777	$8,464,399	41,097
2024	$0	$2,601,804	$6,921,419	$3,918,089	$9,523,223	47,017
2025	$0	$2,672,417	$7,785,811	$4,320,986	$10,458,228	51,852
2026	$0	$2,744,946	$8,549,179	$4,651,609	$11,294,125	55,819
2027	$0	$2,819,444	$9,231,685	$4,924,472	$12,051,129	59,094
2028	$0	$2,895,964	$9,849,826	$5,151,184	$12,745,790	61,814
2029	$0	$2,974,560	$10,417,106	$5,341,035	13391666.57	64,092
2030	$0	$3,055,290	$10,944,591	$5,501,456	$13,999,880	66,017
2031	$0	$3,138,210	$11,441,354	$5,638,394	$14,579,565	67,661
2032	$0	$3,223,381	$11,914,850	$5,756,604	$15,138,232	69,079
2033	$0	$3,310,864	$12,371,209	$5,859,894	$15,682,073	70,319
2034	$0	$3,400,721	$12,815,483	$5,951,308	$16,216,204	71,416
2035	$0	$3,493,016	$13,251,847	$6,033,283	$16,744,864	72,399
2036	$0	$3,587,817	$13,683,761	$6,107,769	$17,271,578	73,293
2037	$0	$3,685,190	$14,114,101	$6,176,325	$17,799,291	74,116
2038	$0	$3,785,206	$14,545,271	$6,240,201	$18,330,478	74,882
Total	**$0**	**$57,126,501**	**$183,870,975**	**$91,032,147**	**$240,997,477**	**1,092,386**

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

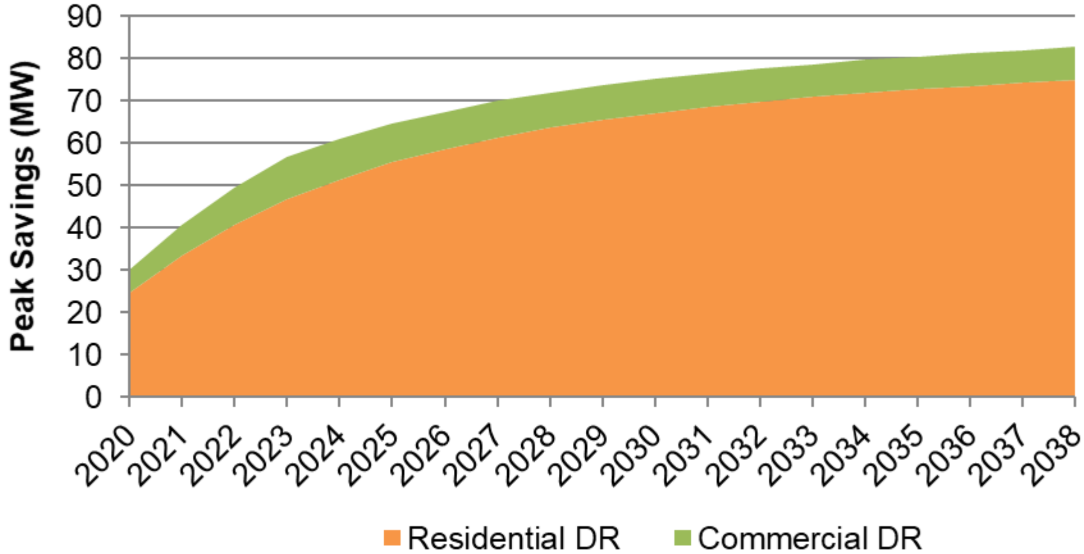
	Participant Costs	Non-Reoccurring Utility Cost	Reoccurring Utility Cost	Utility Incentive Costs	Total Costs (excluding incentives)	Annual kW Reduction:
2020	$0	$201,226	$1,006,131	$1,479,604	$1,207,357	2,959
2021	$0	$205,251	$1,847,256	$2,663,287	$2,052,507	5,327
2022	$0	$214,165	$2,578,188	$3,644,226	$2,792,353	7,288
2023	$0	$218,449	$3,196,044	$4,428,977	$3,414,493	8,858
2024	$0	$111,409	$3,165,016	$4,299,979	$3,276,425	8,600
2025	$0	$113,637	$3,150,838	$4,196,781	$3,264,475	8,394
2026	$0	$115,910	$3,150,633	$4,114,223	$3,266,543	8,228
2027	$0	$118,228	$3,162,056	$4,048,177	$3,280,284	8,096
2028	$0	$120,592	$3,183,200	$3,995,339	$3,303,793	7,991
2029	$0	$123,004	$3,212,513	$3,953,069	$3,335,517	7,906
2030	$0	$125,464	$3,248,733	$3,919,253	$3,374,197	7,839
2031	$0	$127,974	$3,290,834	$3,892,201	$3,418,808	7,784
2032	$0	$130,533	$3,337,987	$3,870,559	$3,468,520	7,741
2033	$0	$133,144	$3,389,517	$3,853,245	$3,522,660	7,706
2034	$0	$135,807	$3,444,879	$3,839,394	$3,580,686	7,679
2035	$0	$138,523	$3,503,636	$3,828,313	$3,642,159	7,657
2036	$0	$141,293	$3,565,433	$3,819,449	$3,706,727	7,639
2037	$0	$144,119	$3,629,990	$3,812,357	$3,774,109	7,625
2038	$0	$147,002	$3,697,079	$3,806,683	$3,844,081	7,613
Total	**$0**	**$2,765,730**	**$58,759,963**	**$71,465,116**	**$61,525,693**	**142,930**

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, exceeding 82 MW in peak reductions by 2038.

Exhibit 2-12. Annual Peak Energy Savings from DR Programs



Source: Newport Partners, LLC

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 *MW*	Transmission DG *MW*	Total DG *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 & Workpaper: Distribution&DG Impact

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 & Workpaper: Distribution&DG Impact

3.2 Increasing DG Penetration in Puerto Rico

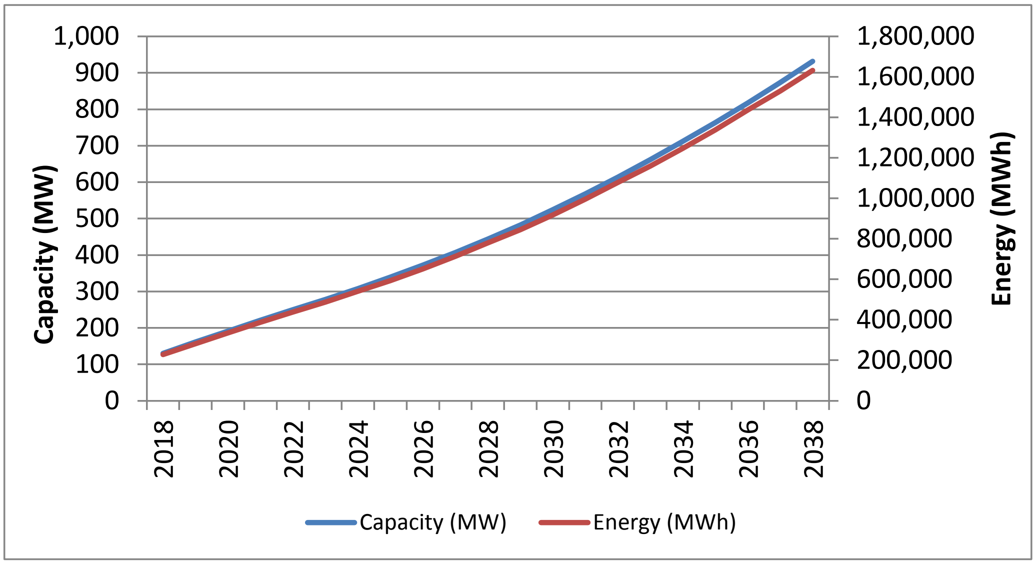
Given the economies of roof top and other forms of DG versus the cost of supply in the island, customer owned generation has experienced an explosive growth from negligible values seen as recently as 2012-2013. This trend, combined with the perception of customers of the need to gain control on their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

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 & Workpaper: Distribution&DG Impact

Exhibit 3-5. CHP Projects by Stages (as of May 2018)

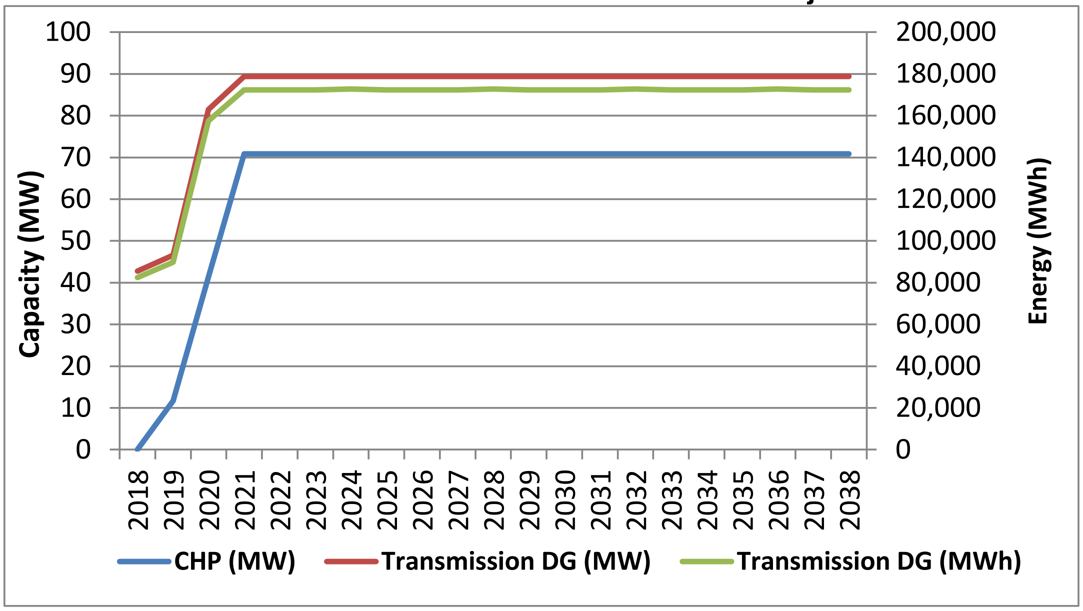
Region	Electric Plans Certified	Evaluated	Incomplete information
	MW	*MW*	*MW*
ARECIBO	0.00	0.00	18.00
BAYAMON	0.00	0.00	0.00
CAGUAS	7.87	9.60	2.50
CAROLINA	3.12	0.00	9.00
MAYAGUEZ	0.67	5.92	0.00
PONCE ES	0.00	0.00	0.00
PONCE OE	0.00	14.21	0.00
S.JUAN	0.00	0.00	0.00
Total	**11.66**	**29.72**	**29.50**

Source: PREPA, Siemens & Workpaper: Distribution&DG Impact

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 & Workpaper: Distribution&DG Impact

Exhibit 3-10 shows the total DG penetration in capacity, including distribution, transmission and cogen and Exhibit 3-11 shows expected energy production from DG at the distribution and transmission level as well as the assumed capacity factors.

3.3 Allocation of DG by Customer Class and Impact on Losses.

For the IRP study it was not necessary to allocate the DG by customer class, however for assessment of revenue it is necessary to allocate this DG. The workpaper "DG Allocation by Customer Class_v1.xlsx has this information and it is based on the mix below identified considering the existing DG in the system and assumes that it will be roughly maintained in the future.

Exhibit 3-7. Allocation of Distribution DG

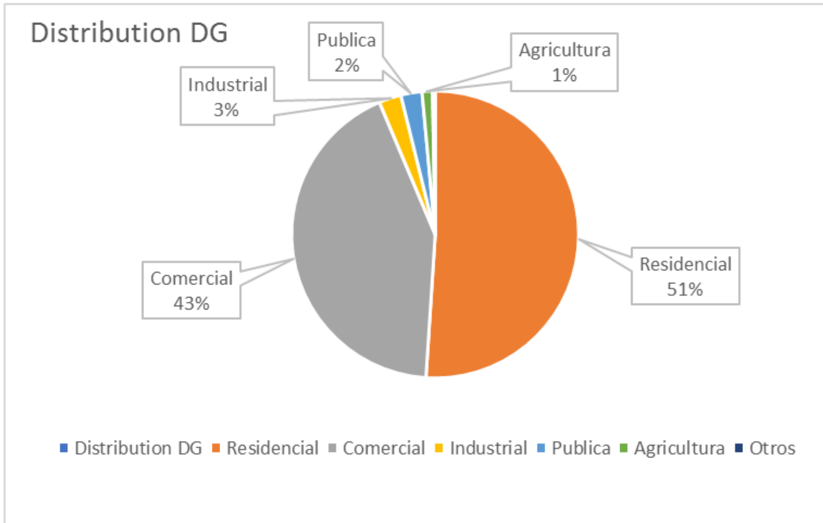


Exhibit 3-8. Allocation of Transmission DG

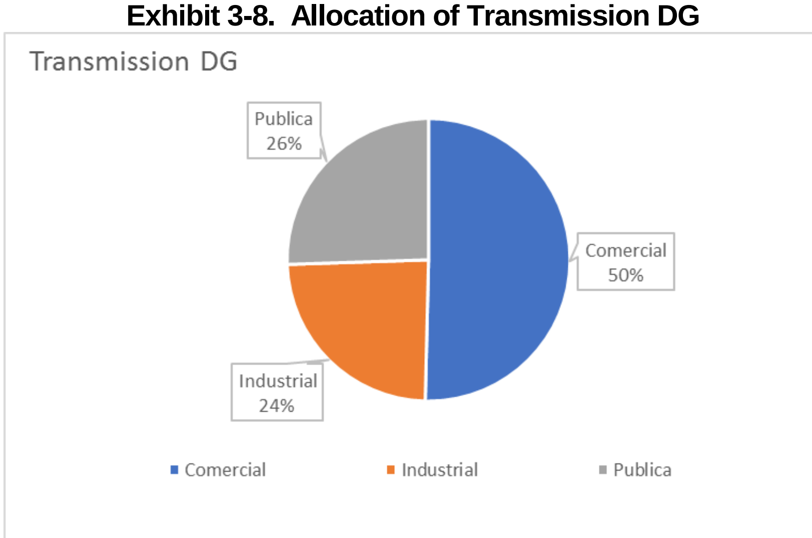
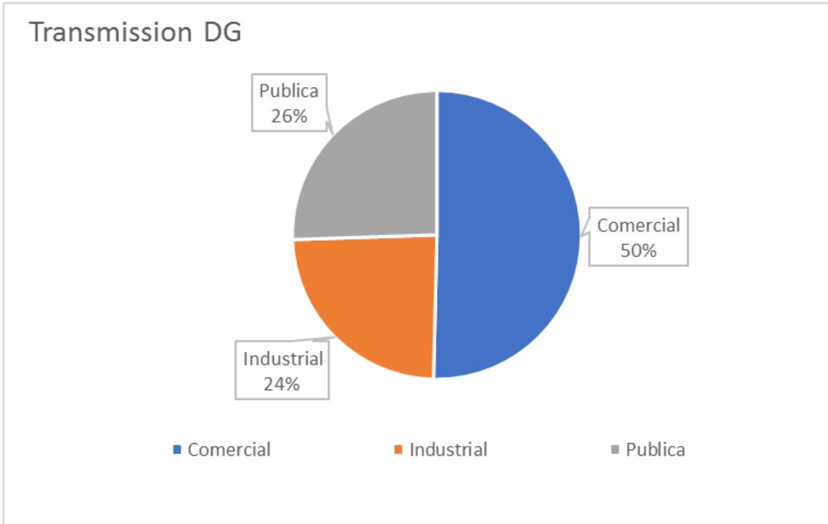


Exhibit 3-9. Allocation of CHP



With respect ot the losses, they cannot be assessed with any level of accuracy without considering the load that is co-located with the DG. Hence this analysis was carried out under Appendix 1; Transmission and Distribution.

Exhibit 3-10. 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 3-11. 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

3.4 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[7]. 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.

3.5 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.

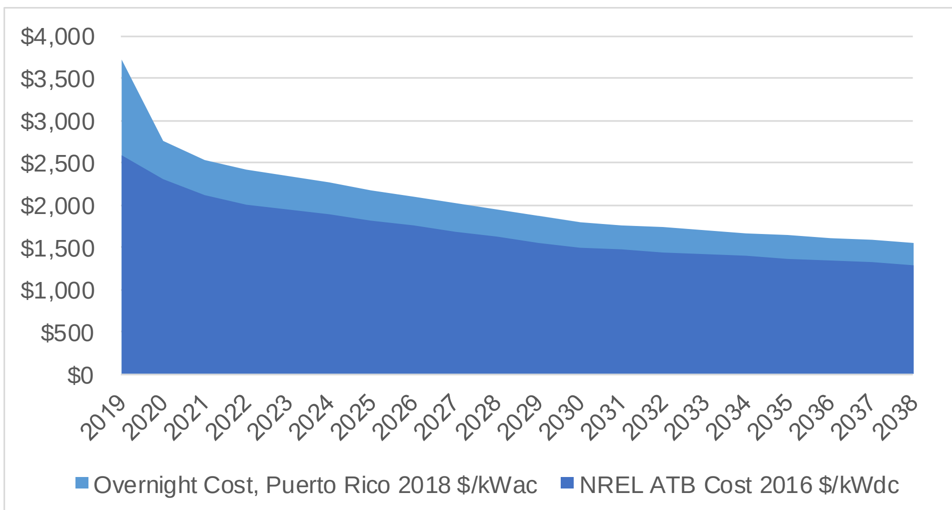
The capital costs for Residential PV are estimated using National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) forecast for residential solar. Further calculations (described below) consistent with the NREL methodology were performed to

[7] 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 3-12 shows the expected projection.

Exhibit 3-12: 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 3-13: 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 3-14.

Exhibit 3-13: Solar PV LCOE Cost Build up

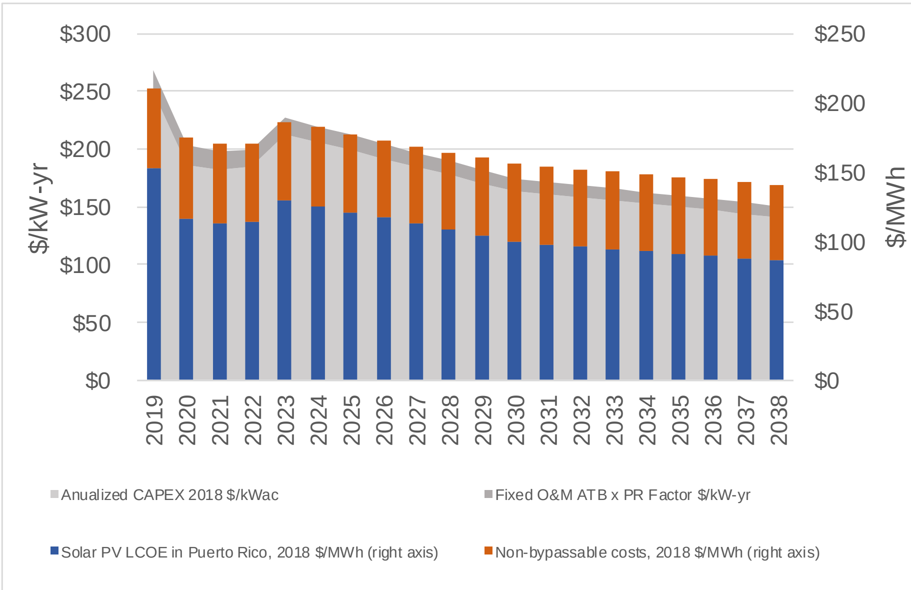


Exhibit 3-14: Residential Solar PV with net metering LCOE Calculations

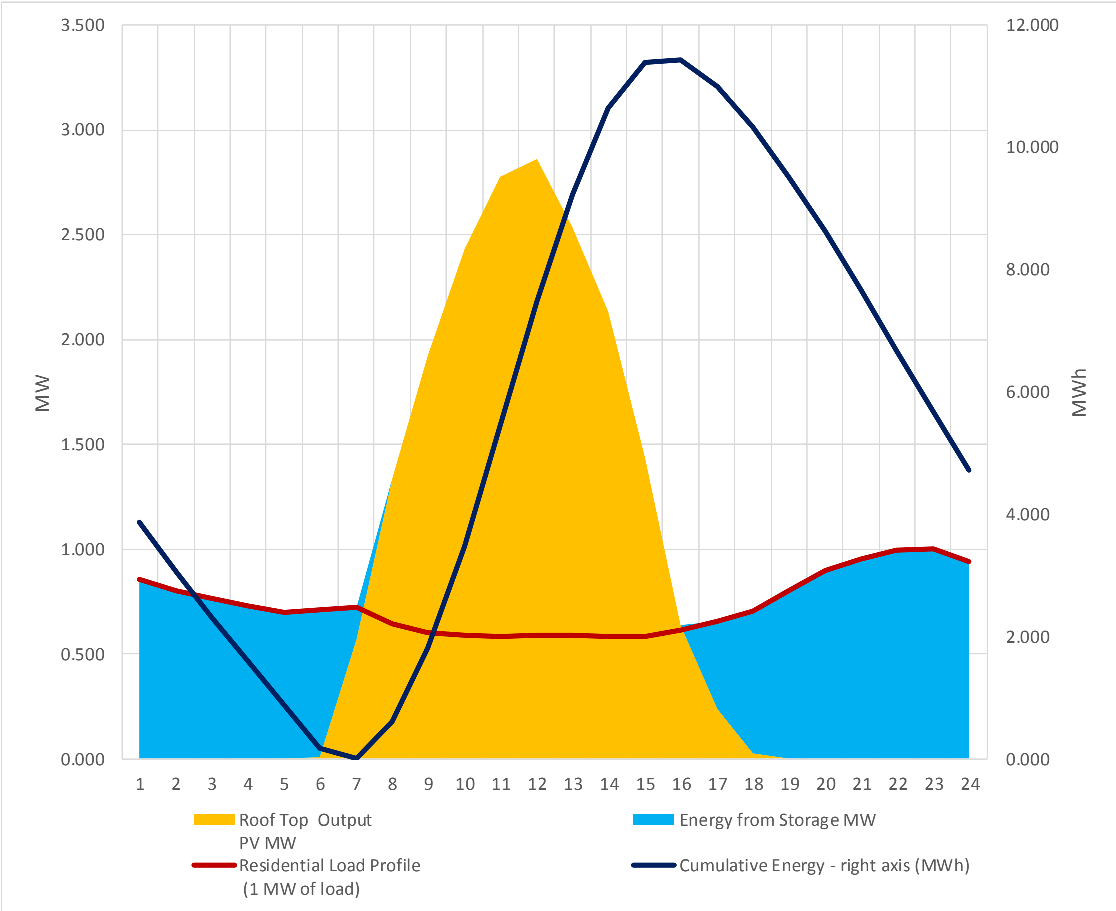
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
NREL ATB Cost 2016 $/kWdc	$2,587	$2,306	$2,116	$2,011	$1,946	$1,882	$1,817	$1,752	$1,687	$1,623	$1,558	$1,493	$1,468	$1,443	$1,417	$1,392	$1,367	$1,341	$1,316	$1,291
PR Factor	16%	16%	16%	16%	16%	16%	16%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

3.6 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.

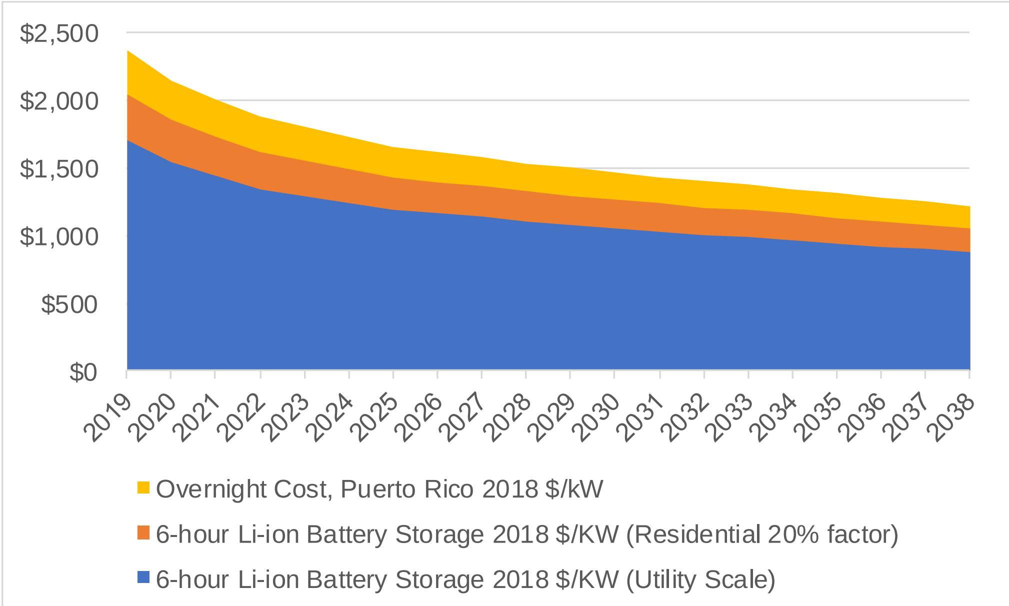
For this option we used a typical Puerto Rico residential consumption profile and determined the amount of PV and Storage capacity that would be required to self-supply. Based on the typical residential consumption profile, we determined that at least a 6 hour battery would be needed to completely self-supply. The demand and supply profile are illustrated in Exhibit 3-15.

Exhibit 3-15: 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 3-16.

Exhibit 3-16: 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 3-17 and the entire detailed cost are presented in Exhibit 3-18.

Exhibit 3-17: Storage System LCOE Cost Build up

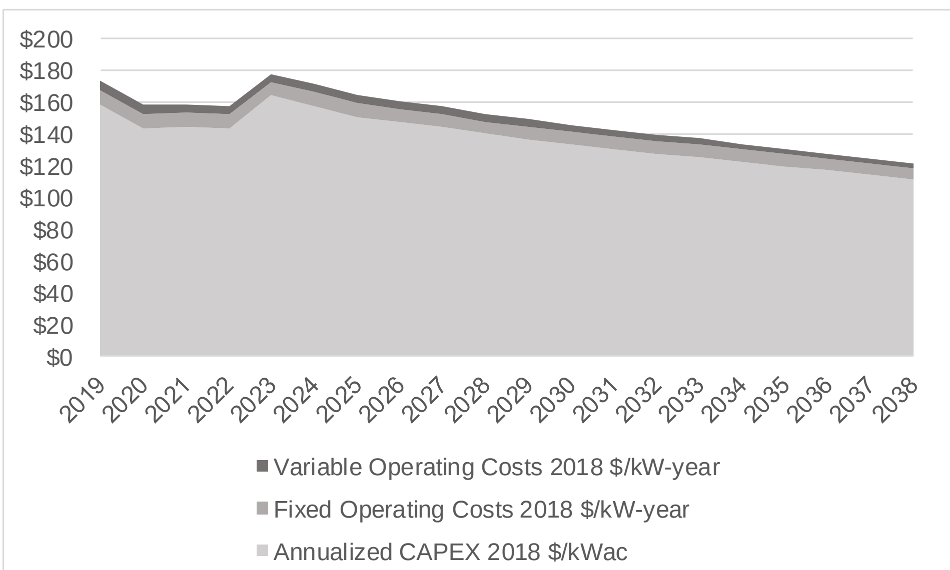


Exhibit 3-18: Storage System LCOE Calculations

	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**

Exhibit 3-19: 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 3-19.

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[8], 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%[8].

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[8] 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.

[8] 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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