

TRADING PARTNER



# DR Potential Study

NEPR-MI-2020-0012

# DR Potential Study

## Transmittal Letter

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Dear Mr. Mount,

Enclosed please find the “Demand Response Potential Assessment” Study Report. LUMA contracted with Guidehouse to conduct this study as an input to LUMA’s 2024 Integrated Resource Plan (IRP) for calendar years CY 2025 to CY 2044. The objective of this study was to estimate the achievable technical potential for summer peak demand reduction for LUMA from a portfolio of Demand Response (DR) measures across all customer sectors (residential, commercial, industrial), and from electric vehicles and behind-the-meter batteries over the CY 2025-2044 timeframe.

For the purposes of this study, LUMA asked Guidehouse to leverage the previous EE/DR modelling work undertaken by National Renewable Energy Laboratory (NREL) for Puerto Rico. The NREL Puerto Rico Demand Response Impact and Forecast Tool<sup>1</sup> (PR-DRIFT) was modified by Guidehouse to reflect various methodological refinements that Guidehouse typically employs in DR potential studies that it has completed for various clients in the mainland USA and other countries. Due to relatively limited data available for Puerto Rico, Guidehouse leveraged previous DR analysis undertaken by Guidehouse in the development of the LUMA EE/DR Transition Period Plan (TPP) and focused its research and analytic efforts on those DR measures that are most relevant for Puerto Rico and are expected to provide the greatest long-term impact. This study provides “achievable” annual potential estimates by DR measure and costs associated with attaining the DR savings. “Achievable” represents the amount of potential that could realistically be realized given market conditions, assumptions on program enrollment, and budget constraints. This study did not assess measure cost-effectiveness (outside study scope).

The attached report presents a detailed description of the approach, data inputs and assumptions used for the analysis. It presents the findings from the analysis with a detailed description of the study results in

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<sup>1</sup> National Renewable Energy Lab, “PR-DRIFT: Puerto Rico Demand Response Impact and Forecast Tool”, <https://www.nrel.gov/state-local-tribal/pr-drift.html>

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the main body of the report and the report appendices. The study findings highlight the significant summer peak demand reduction potential from Demand Response that could potentially be achieved from different customer sectors and end-uses with DR-enabling technologies and their associated levelized costs, that could help LUMA prioritize the Company's DR activities. The report provides suggestions for further refinements to the DR potential analysis and discusses the expected evolution of DR in the industry and implications for future DR considerations in Puerto Rico.

For additional questions, please contact me at [debyani.ghosh@guidehouse.com](mailto:debyani.ghosh@guidehouse.com).

Sincerely,



Debyani Ghosh

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# DR Potential Study

## 1. Executive Summary

LUMA contracted with Guidehouse to complete a high-level Demand Response (DR) Potential Study as a possible input to the LUMA's 2024 Integrated Resource Plan (IRP) for calendar years CY 2025 to CY 2044.

To expedite the DR potential study and align with previous modelling efforts, LUMA asked Guidehouse to leverage the previous EE/DR modelling work undertaken by National Renewable Energy Laboratory (NREL) for Puerto Rico. The NREL Puerto Rico Demand Response Impact and Forecast Tool<sup>2</sup> (PR-DRIFT) was modified by Guidehouse to reflect various methodological refinements that Guidehouse typically employs in DR potential studies that it has completed for various clients in the mainland USA and other countries.

Due to relatively limited data available for Puerto Rico, Guidehouse leveraged previous DR analysis undertaken by Guidehouse in the development of the LUMA EE/DR Transition Period Plan (TPP) and focused its research and analytic efforts on those DR measures that are most relevant for Puerto Rico and are expected to provide the greatest long-term impact.

Potential assessment typically consists of three levels – technical, economic, and achievable. “Technical” potential for DR refers to the maximum theoretical potential that could be realized if 100% of eligible customers or load were enrolled in a DR program. It sets the theoretical upper bound on the amount of savings that could be realized. “Economic” is a subset of the technical potential based on cost-effectiveness and only includes measures that are cost-effective. “Achievable” represents the amount of potential that could realistically be realized given market conditions, assumptions on program enrollment, and budget constraints. This study did not assess measure cost-effectiveness (outside study scope) and from that standpoint the potential estimates presented in this study can be characterized as “achievable technical” potential.

### 1.1 Approach

The objective of this study was to estimate the achievable technical potential for summer peak demand reduction for LUMA from a portfolio of DR measures across all customer sectors (residential, commercial, industrial) and from electric vehicles<sup>3</sup> over the CY 2025-2044 timeframe. This study provides achievable annual potential estimates by DR measure and costs associated with attaining the DR savings. As mentioned above, the study did not evaluate or consider the cost-effectiveness of measures.

DR has multiple use cases in addition to peak demand reduction that include – using DR to address grid emergencies, as an economic resource to reduce demand during periods of high energy prices (which may coincide with peak demand periods), serving as a non-wires alternative (NWA) to address transmission and distribution needs, and for providing ancillary services (frequency regulation, spinning

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<sup>2</sup> National Renewable Energy Lab, “PR-DRIFT: Puerto Rico Demand Response Impact and Forecast Tool”, <https://www.nrel.gov/state-local-tribal/pr-drift.html><https://www.nrel.gov/state-local-tribal/pr-drift.html>

<sup>3</sup> For the purposes of this analysis, electric vehicles are represented as a separate factor with separate characterization of baseline charging and demand from different classes of electric vehicles and DR impacts.

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and non-spinning reserves). This study solely considers DR for the purposes of system summer peak reduction.

The three key steps Guidehouse used to estimate the DR potential are summarized below:

1. Characterize the “market” for DR across the residential, commercial, and industrial sectors) based on the energy, peak demand and customer forecast developed by Guidehouse for LUMA’S IRP. Additionally, electric vehicles are characterized as a separate sector in this study. Market characterization for DR entails development of baseline count and peak demand projections<sup>4</sup>.
2. Identify the DR measures available for each sector, select the most relevant DR measures and develop a sectoral participation hierarchy defining how a customer choice of one of the DR measures would preclude availability of other DR measures to avoid double-counting of impacts from multiple DR measures that can potentially be offered to the same customers.
3. Develop assumptions to inform the costs, participation, and impact multipliers for each DR measure.

Guidehouse leveraged the PR-DRIFT model from NREL along with both internal and external data sources to develop assumptions and estimates.

While this study focuses on DR, some of the technologies analyzed in this study also have the potential to increase demand when beneficial to the system. For example, end use appliances such as HVAC systems, electric water heating, and batteries used in distributed storage or EVs in charging mode can be called upon to increase their demand. The ability to increase demand can prove beneficial to distribution system elements, or to the larger grid, to absorb solar PV production during the daylight hours. While DR includes only demand reduction measures, Flexible Demand (FD) includes DR measures and measures that can be called upon to increase demand when needed. While some of the measures discussed may have the capability of increasing demand their potential for this capability was not addressed in this study.

Table 1 shows the DR measures identified as most relevant for Puerto Rico by Guidehouse in consultation with LUMA staff. Characteristics specific to Puerto Rico, such as its tropical climate and equipment stock, were considered to select the most relevant measures for LUMA’s consideration.

EV measures for Light Duty Electric Vehicles (LDV) and Medium and Heavy-Duty Electric Vehicles (MHDV) were not included in the TPP and the original NREL model. However, with the growing popularity and applicability of EVs, Guidehouse identified some EV-related DR measures – EV TOU rates, EV managed charging and EV V2X – which have significant long-term potential.

In addition to the measures listed below, Guidehouse assessed potential load shift capacity to backup generators at C&I customer facilities (presented in Appendix C) but did not include those estimates in the total potential since 1) these backup generators are expected be called for emergency DR events rather than in response to summer peak demand reduction needs, 2) there is considerable uncertainty about whether the existing backup generators could be permitted for such use, and 3) there is considerable

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<sup>4</sup> Baseline peak demand projections refers to the peak demand projections before consideration of DR impacts.

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uncertainty about the technical requirements and associated costs for modifying the backup generators for such use.

Multiple DR measures applicable to the same sector were allocated across the sectoral customer base according to a participation hierarchy to avoid double counting of DR impacts from overlapping measures offered to the same customers (described further in the report).

**Table 1-1: Most Relevant Demand Response Measures for Puerto Rico**

Demand Response Measure	Applicable Sectors	Description
Direct Load Control (DLC) - Window Air Conditioning (AC) Control	Res	Control of window ACs by a thermostat and/or load control switch.
DLC - Ductless Mini Split/Heat Pump Control	Res	Control of ductless mini split AC or heat pump by a thermostat and/or load control switch.
DLC - Water Heating Control	Res	Control of water heating loads using a load control switch.
Commercial and Industrial (C&I) Curtailment – Heating, Ventilation, and Air Conditioning (HVAC) Control - Manual	Com, Ind	Manual enabled load reduction. Typically, customers have a firm load reduction commitment.
C&I Curtailment - HVAC Control - Auto DR	Com	Auto-DR enabled load reduction. Typically, customers have a firm load reduction commitment.
TOU Rates	Res, Com, Ind	Time varying rate offers with a tiered pricing for on and off-peak hours.
CPP without enabling tech	Res, Com	Time varying rate offers during pre-determined peak demand times.
CPP with enabling tech	Res, Com, Ind	Time varying rate offers during pre-determined peak demand times.
Res Behind the Meter (BTM) Battery Dispatch	Res Battery	Use of BTM batteries for load shifting and/or dispatch during peak demand periods <sup>5</sup> .
Electric Vehicle (EV) Managed Charging	EV LDV, EV MHDV	Managed charging of electric vehicles for peak demand reduction.
EV Time-Of-Use	EV LDV, EV MHDV	Time varying rate offers with a tiered pricing for on and off-peak hours for EV charging.
EV Vehicle to Everything (V2X)	EV LDV, EV MHDV	Allows for electricity in EV batteries to be transferred to buildings, the grid, etc.

<sup>5</sup> This study only included discharge of batteries to reduce peak demand. We did not model charging of batteries during renewable curtailment periods since it was not within the study scope. However, charging of batteries to mitigate renewable curtailment should be considered as an additional value stream from batteries for Puerto Rico.

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## 1.2 Key Findings

The key findings from the analysis are noted below. All potential results presented in this report represent MW capacity at the generator.

- **The estimated potential savings for the top 40 hours of demand is 686 MW in CY 2044 at a total cost of \$164 million.** Note that this level of DR savings would not actually reduce peak demand this amount because the 41<sup>st</sup> highest peak demand hour absent DR would become the highest demand hour after the impact of DR for the top 40 hours. Further analysis beyond the scope of this study would be required to determine the optimal allocation of the available DR capacity across more of the peak demand hours, but a simple first-order approximation by Guidehouse suggests that optimal deployment of the forecast DR resources across the top 400 or so hours in 2044 would provide a reduction in system peak demand of somewhere in the range of 300 – 400 MW.
- **In CY 2044, most of the DR potential comes from LDV V2X at 346 MW and Residential BTM Battery Dispatch at 73 MW,** this potential is not associated with end-use load reduction. Instead, it represents DR capacity that could potentially be available from dispatch and export from EVs (when plugged in but not charging) and export from BTM stationary batteries. The most significant DR measures that represent load shedding during DR events (i.e., all measures other than V2X and BTM Battery Dispatch) are LDV Managed Charging at 68 MW, MHDV Managed Charging at 46 MW, and MHDV V2X at 38 MW.
- **The top contributor to the estimated DR potential for CY34 is Residential BTM Battery Dispatch.** The next most impactful measures are Commercial CPP with enabling tech at 26 MW, Residential CPP with Enabling Tech at 22 MW, and Residential TOU Rates at 15 MW. After that, EV V2X for LDV is at 11 MW and Residential CPP without enabling tech is at 9 MW.

Figure 1 shows the estimated demand reduction potential over the forecast period for each sector. The residential sector has the highest medium term potential due primarily to BTM Battery Dispatch, while the EV sector has the highest long-term potential due primarily to V2X.

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Figure 1: Demand Reduction Over Forecast Period by Sector (MW at generator)

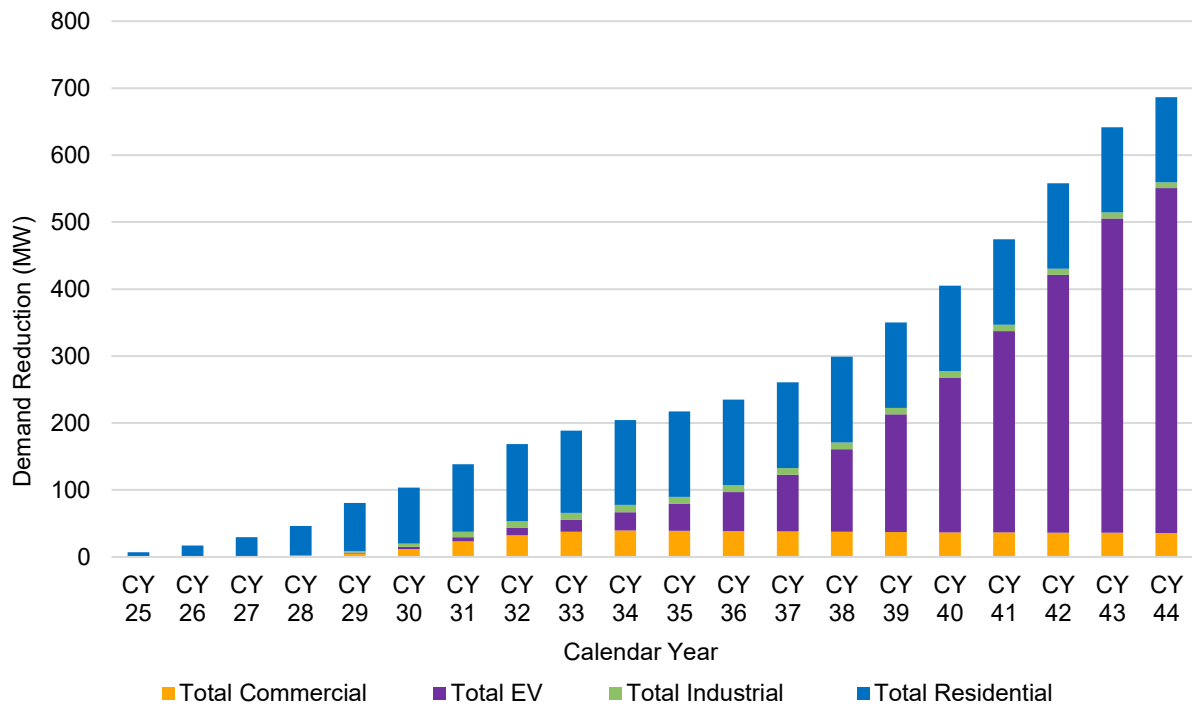


Figure 2 shows the estimated demand reduction potential for each individual measure in CY 2034 and CY 2044. The results are color coded by sector and measure.

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Figure 2: Demand Reduction in CY 2030 and CY 2044 by Measure (MW at generator)

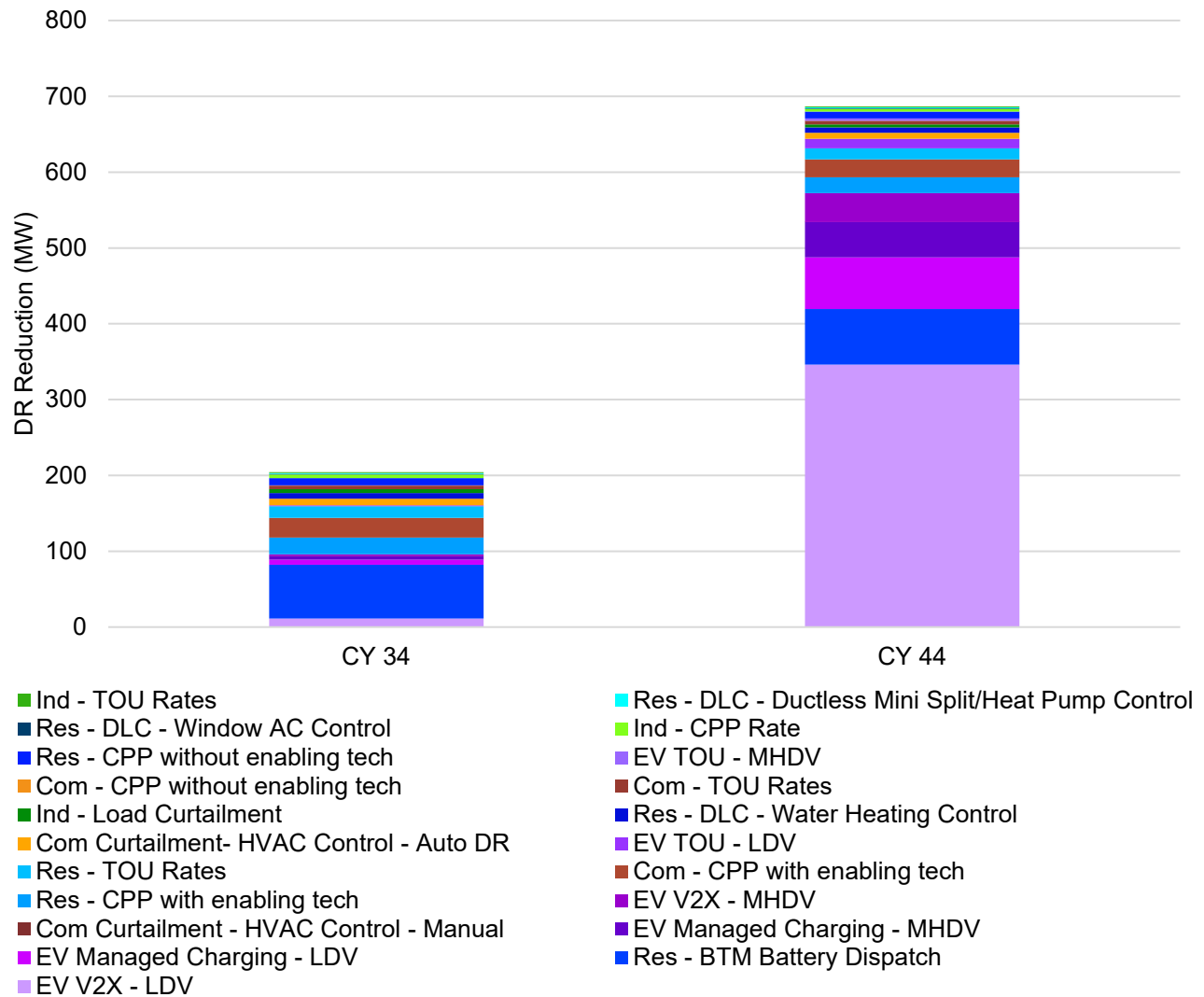


Figure 3 shows the projected cost over the entire portfolio over the forecast period in real 2023 dollars<sup>6</sup>. Figure 4 shows the levelized cost assumptions for each measure. These are based on meter values. In terms of the different cost components, these levelized costs include:

- Incentives offered to customers to participate in DR
- Program administration costs including upfront program development costs, program marketing and customer outreach at the time of program launch

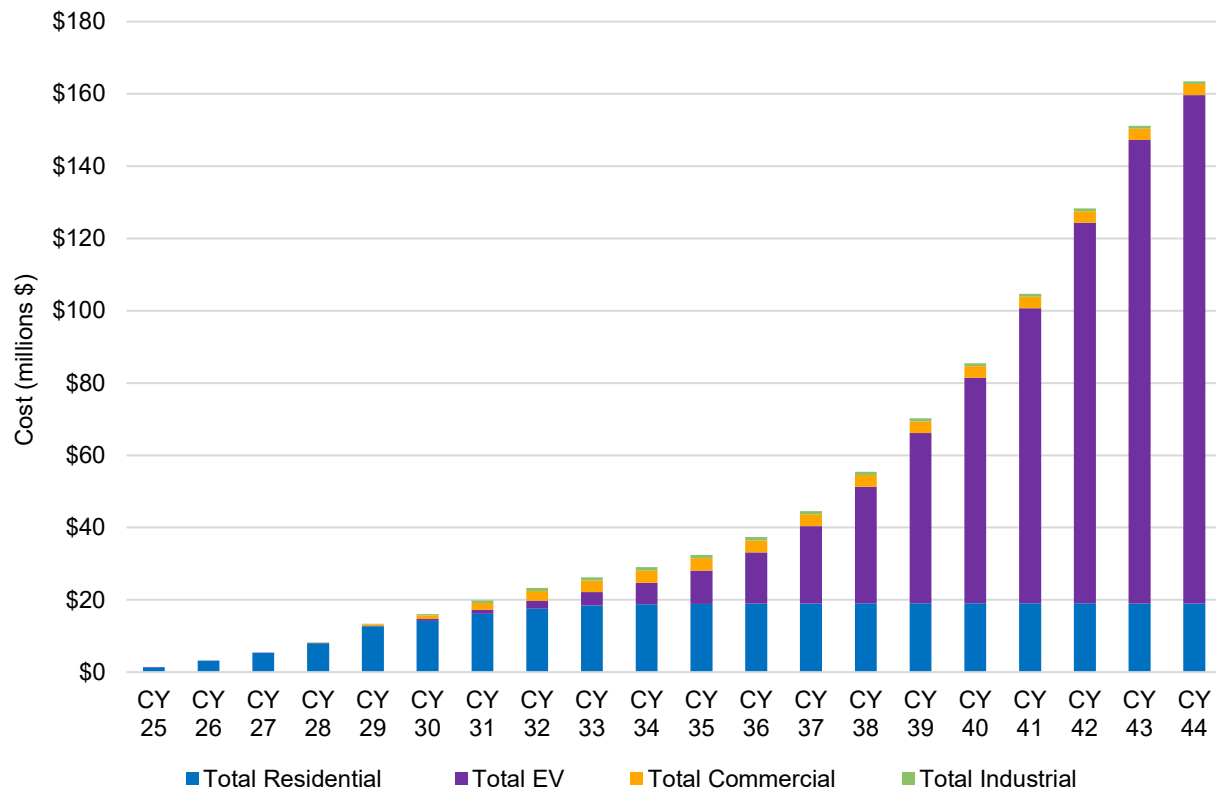
<sup>6</sup> All costs presented in this report are in real 2023 dollar values.

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- Program delivery costs which may include payments to third-party aggregators (in cases where programs are third-party administered), and
- Operations and maintenance costs (primarily communication costs associated with connectivity and control of devices).

For time-varying rates (TOU and CPP), the levelized costs do not include Advanced Metering Infrastructure (AMI)<sup>7</sup> costs and other costs associated with changes to LUMA's billing system that may be required for administration of time-varying rates. Also, the levelized costs do not include capital expenditure for procurement of Demand Response Management System (DRMS)/Distributed Energy Resource Management System (DERMS). Additionally, customer "hassle factor" for participation in DR and related customer inconvenience costs are not incorporated in the levelized costs.

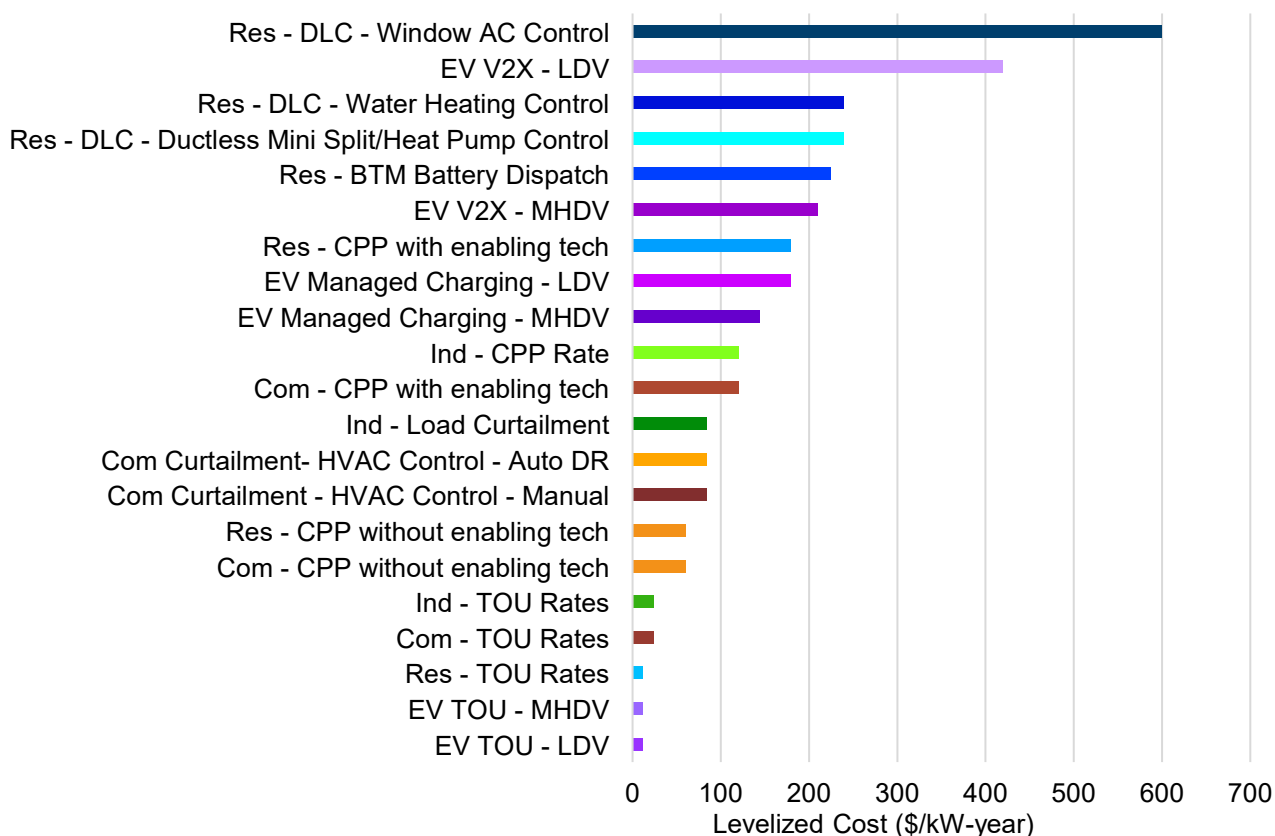
**Figure 3: Projected Annual Cost of Entire Portfolio Over Forecast Period**



<sup>7</sup> Time-varying rate offers (TOU, CPP) require AMI. We assumed that these rates are offered after AMI is deployed. However, AMI costs or billing system changes/upgrades costs are not included in the TOU and CPP levelized costs.

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**Figure 4: Estimated Levelized Cost by Measure (\$/kW-year)**



Note that most of the rate-related DR measures such as TOU rates and dynamic pricing have relatively low costs primarily because the cost of the AMI infrastructure necessary to enable TOU and dynamic pricing has NOT been included. One exception to this is the residential critical peak pricing with enabling technology because this measure includes costs for a customer incentive for the enabling technology.

## 1.3 Suggested Next Steps

In terms of next steps and further refinements to this estimate of DR potential for Puerto Rico, Guidehouse suggests further research to refine the key assumptions driving the DR potential forecast, with a focus on the top four DR measures forecast to have the most significant contribution to the CY 2034 DR potential.

Guidehouse’ primary focus in this study was identifying the “traditional” DR capacity available in Puerto Rico that could serve as a cost-effective alternative to traditional generation capacity. There are also other potential uses for DR – such as providing frequency regulation support and operating reserves – that were beyond the scope of this limited study. As time and resources permit, Guidehouse recommends that LUMA work to better understand how the current list of DR measures, and other more novel DR measures, could be modified to provide more sophisticated DR capacity for Puerto Rico.

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## 2. Introduction and Background

To support its IRP, LUMA asked Guidehouse to develop an estimate of the demand response capacity that could be available in Puerto Rico over the 20-year IRP forecast period.

To expedite the DR potential study and align with previous modelling efforts, LUMA asked Guidehouse to leverage the previous EE/DR modelling work undertaken by NREL for Puerto Rico. Thus, the NREL PR-DRIFT formed the basis of the model that Guidehouse used in the study.<sup>8</sup> This model was then modified to reflect various methodological refinements that Guidehouse typically employs in DR potential studies it has done for various clients in the mainland and other countries.

As compared to many other jurisdictions for which there is comprehensive and accurate data available to inform a DR potential study, there is relatively limited data available for Puerto Rico. Given this relative paucity of data, Guidehouse leveraged previous DR analysis undertaken by Guidehouse in the development of the EE/DR Transition Period Plan and focused its research and analytic efforts on those DR measures that are expected to provide the greatest economic benefit for Puerto Rico.

Finally, LUMA asked Guidehouse to estimate what could be described as the “Realistic Achievable” DR potential absent any economic or cost-effectiveness constraints (cost-effectiveness assessment of the various DR measures was outside the scope of this analysis). Potential assessment typically consists of three levels – technical, economic, and achievable. “Technical” potential for DR refers to the maximum theoretical potential that could be realized if 100% of eligible customers or load were enrolled in a DR program. It sets the theoretical upper bound on the amount of savings that could be realized. Typically, the technical potential can never actually be realized for a variety of technical, economic, and behavioral reasons. “Economic” is a subset of the technical potential based on cost-effectiveness and only includes measures that are cost-effective. “Achievable” represents the amount of potential that could realistically be realized given market conditions, assumptions on program enrollment, and budget constraints.

While there was insufficient Puerto Rico data available to perform a meaningful cost effectiveness analysis for this study, Guidehouse included only measures that were deemed both appropriate to the Puerto Rico environment and are regularly found to be cost effective in other jurisdictions with lower power costs. In other jurisdictions, where data for economic screening of DR measure is available, higher power costs tend to support an expanded range of cost-effective DR measures.

With the mandate for developing a Realistic Achievable potential, Guidehouse included a variety of conservative assumptions and approaches in its analysis with the aim to provide estimates of the DR potential available in any given year during the forecast period regardless of cost-effectiveness. As such, the potential estimates presented in this study could also be characterized as “achievable technical” potential. These estimates are realistically achievable based on Guidehouse experience in evaluating numerous DR programs covering many DR measures over the past twenty years. These estimates represent what could “most likely” be achievable given plausible assumptions on technology uptake and program enrollment. The assumptions and approaches are described in the following section.

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<sup>8</sup> National Renewable Energy Lab, “PR-DRIFT: Puerto Rico Demand Response Impact and Forecast Tool”, <https://www.nrel.gov/state-local-tribal/pr-drift.html>

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The analysis presented in the report is a simplified analysis and does not consider alternative scenarios or sensitivity and uncertainty analysis. More detailed assessment would require uncertainty analysis and present ranges for potential estimates and associated costs with the scenarios.

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## 3. Approach and Assumptions

This section provides details of the approach and assumptions used by Guidehouse in developing its estimate of the DR potential for Puerto Rico. The structure of this section follows the process that Guidehouse used in the study. This section begins with a description of the NREL model and modifications that Guidehouse made to the model for this study. This is followed by a description of the approach Guidehouse used to identify the most relevant DR measures for Puerto Rico. The general framework for developing DR and cost estimates is then provided and is followed by subsections for each sector (residential, commercial, and industrial) describing any unique aspects of the analytic framework for that sector and the key assumptions for each of the DR measures applicable to that sector. All results within this report are presented at the generator level unless otherwise stated.

### 3.1 Use and Modification of NREL Model

NREL developed the PR-DRIFT in 2022 as a tool to help decision makers estimate potential impacts due to demand response, energy efficiency, variable renewable energy, and storage adoption measures.<sup>9</sup> The original model uses 8760 load data from Puerto Rico Electric Power Authority (PREPA) 2016-2017 IRP to develop load forecasts through CY 2040. Through various user inputs, users can select a specific fiscal year, month, demand level, and number of peak hours to evaluate. The final output gives peak net gross demand for the selected year, reduction in peak net gross demand due to demand response resources, and the percentage reduction.

Guidehouse leveraged the NREL PR-DRIFT to develop a high-level, LUMA-specific demand response model. Energy efficiency and variable renewable energy are outside of the scope of the Guidehouse model. With a narrowed focus, the new model analyzes 21 demand response measures across four sectors: residential, commercial, industrial, and electric vehicles (EVs). Using a list of assumptions developed by Guidehouse, each measure has a calculated Participation Multiplier and Impact Multiplier. The two multipliers combined with the LUMA's load forecast by sector create the demand reduction. The analysis also incorporated levelized cost assumptions for each measure and calculated annual costs. Users of the model can input the following information to view specific results:

- Customer Demand by Sector
- Calendar Year: CY 2025 to CY 2044
- Month
- Residential, Commercial, and Industrial measures to evaluate
- Set # of Hours to be included in the peak period
- Levelized costs by measure
- Puerto Rico Cost Adder (%)

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<sup>9</sup> National Renewable Energy Lab, "PR-DRIFT: Puerto Rico Demand Response Impact and Forecast Tool", <https://www.nrel.gov/state-local-tribal/pr-drift.html>

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### 3.2 Most Relevant DR Measures for Puerto Rico

Guidehouse began with the list of DR measures used in LUMA's EE/DR TPP as a starting point to identify the most relevant DR measures for Puerto Rico. DR measures that were deemed not relevant for Puerto Rico based on market characteristics and/or usually provide limited savings based on experience from other jurisdictions were screened out. Characteristics specific to Puerto Rico, such as its tropical climate and equipment stock, were considered to select the most relevant measures for LUMA's consideration. For example, most Puerto Ricans utilize window AC units and ductless mini split units rather than central AC units. As a result, these two end-use technologies were considered relevant for Puerto Rico. The selected DR measures targeted end uses that were most applicable to Puerto Rico. These included the HVAC and water heating end uses, which were prioritized over other end uses such as lighting or pool pumps. Examples of measures that were screened out include central AC control and pool pump control for residential, Behavioral Demand Response (BDR), water heating and refrigeration control for commercial customers.

EV measures were not included in the TPP and the original NREL model. However, with the growing popularity and applicability of EVs, Guidehouse identified some EV-related DR measures – EV TOU rates, EV managed charging and EV V2X – which have significant long-term potential.

Table 2 lists the relevant DR measures included in the potential estimates. In addition to the measures listed below, Guidehouse assessed potential load shift capacity to backup generators at C&I customer facilities (presented in Appendix C) but did not include those estimates in the total potential since 1) these backup generators are expected be called for emergency DR events rather than in response to summer peak demand reduction needs, 2) there is considerable uncertainty about whether the existing backup generators could be permitted for such use, and 3) there is considerable uncertainty about the technical requirements and associated costs for modifying the backup generators for such use.

Multiple DR measures applicable to the same sector considered a participation hierarchy to avoid double counting of DR impacts from overlapping measures offered to the same customers (described further in the report).

**Table 3-1: Demand Response Measures Relevant for Puerto Rico**

Demand Response Measure	Applicable Sectors	Description
<b>Direct Load Control (DLC) - Window Air Conditioning (AC) Control</b>	Res	Control of window ACs by a thermostat and/or load control switch.
<b>DLC - Ductless Mini Split/Heat Pump Control</b>	Res	Control of ductless mini split AC or heat pump by a thermostat and/or load control switch.
<b>DLC - Water Heating Control</b>	Res	Control of water heating loads using a load control switch.
<b>Commercial and Industrial (C&amp;I) Curtailment – Heating, Ventilation, and Air</b>	Com, Ind	Manual enabled load reduction. Typically, customers have a firm load reduction commitment.

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Demand Response Measure	Applicable Sectors	Description
<b>Conditioning (HVAC) Control - Manual</b>		
<b>C&amp;I Curtailment - HVAC Control - Auto DR</b>	Com	Auto-DR enabled load reduction. Typically, customers have a firm load reduction commitment.
<b>TOU Rates</b>	Res, Com, Ind	Time varying rate offers with a tiered pricing for on and off-peak hours.
<b>CPP without enabling tech</b>	Res, Com	Time varying rate offers during pre-determined peak demand times.
<b>CPP with enabling tech</b>	Res, Com, Ind	Time varying rate offers during pre-determined peak demand times.
<b>Res Behind the Meter (BTM) Battery Dispatch</b>	Res Battery	Use of BTM batteries for load shifting and/or dispatch during peak demand periods.
<b>Electric Vehicle (EV) Managed Charging</b>	EV LDV, EV MHDV	Managed charging of electric vehicles for peak demand reduction.
<b>EV Time-Of-Use</b>	EV LDV, EV MHDV	Time varying rate offers with a tiered pricing for on and off-peak hours for EV charging.
<b>EV Vehicle to Everything (V2X)</b>	EV LDV, EV MHDV	Allows for electricity in EV batteries to be transferred to buildings, the grid, etc.

### 3.3 Approach for DR Potential and Cost Estimation

Having identified the most relevant DR measures for Puerto Rico, the next step in the approach was developing estimates of demand response impacts and costs for each of the measures. These are described in the following subsections.

Guidehouse's DR potential estimation methodology is summarized below and described in this section:

1. Define peak period.
2. Characterize the market for DR estimates for the four different sectors - residential, commercial, industrial, and electric vehicles.
3. Develop a sectoral participation hierarchy so as not to double count impacts from multiple DR measures offered to the same sector, as listed in the previous section.

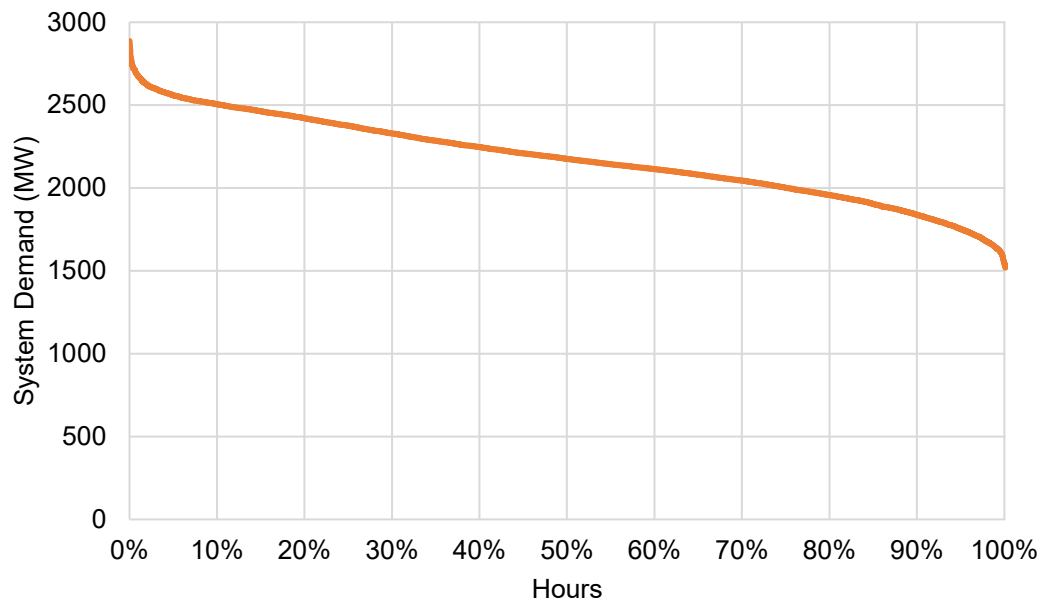
# DR Potential Study

4. Develop assumptions to inform the participation and impact multipliers for each DR measure. Estimate the DR potential using these multipliers over the forecast period.

## 3.3.1 Peak Period Definition

Guidehouse developed a duration curve for CY34 by sorting the hourly demand from highest to lowest. This duration curve is provided in Figure 5 and shows that the hourly demand in CY34 ranges from a minimum of just over 1500 MW to a maximum of almost 3000 MW.

**Figure 5: CY34 Hourly Demand Duration Curve**



As shown, the 40 highest demand hours in CY34 cover the top 163 MW (top 6%) of demand and the highest 100 demand hours cover the top 220 MW (top 8%) of demand. Based on the shape of this area of the duration curve and given Guidehouse experience with other DR programs and measures in other jurisdictions, Guidehouse set the Peak Period to be the highest 40 hours of demand which cover the top 163 MW (top 6%) of demand. Practically speaking, this means that DR measures would typically be “dispatched” less than 1% of the time (40 hours of the 8760 hours in a year), which is generally acceptable to DR program participants. Increasing the number of hours in the Peak Period beyond 40 would not yield a significant increase in the potential demand savings from the DR portfolio but would risk lower willingness to participate by potential participants for some of the DR measures. That said, Guidehouse is also confident that slightly longer Peak Periods – up to 100 hours – would not change the results of this study materially. This allows LUMA some flexibility to adjust the Peak Period to suit its planning and operational requirements. Resources such as electric vehicles and BTM batteries are favorable toward longer dispatch than end-uses such as HVAC. Therefore, LUMA could consider variations in dispatch duration by resource and end-use type.

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For the purposes of defining the peak period in which the various DR measures would be “dispatched”, Guidehouse analyzed the top 100 hours of the duration curve for CY34. A close-up of this region of the curve is shown in Figure 6.

**Figure 6: CY34 Top 100 Hours of Duration Curve**

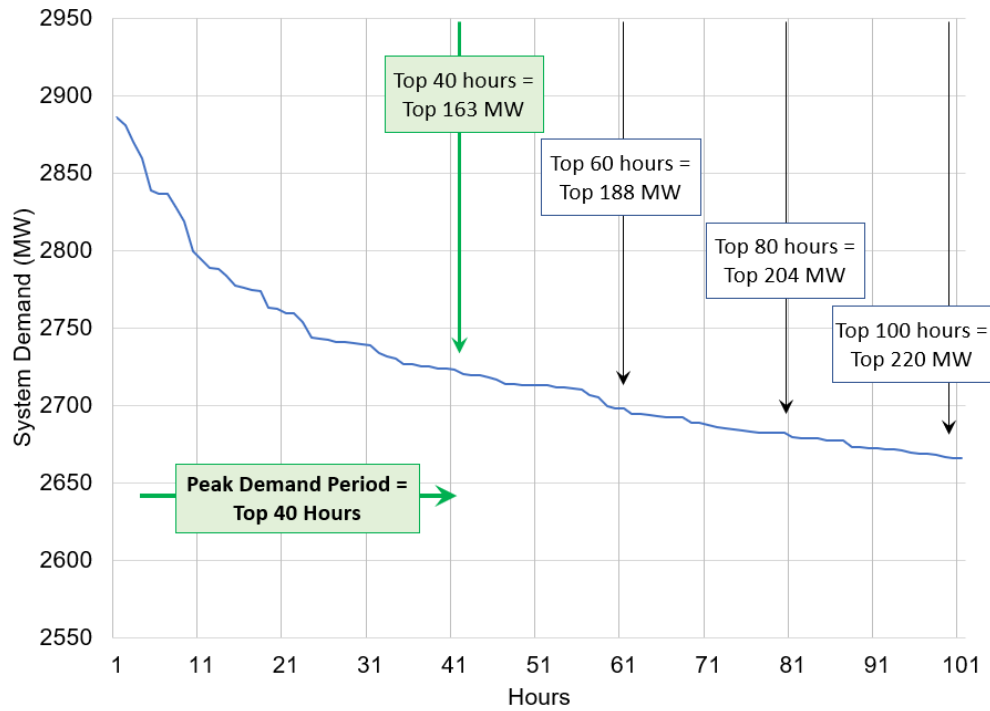
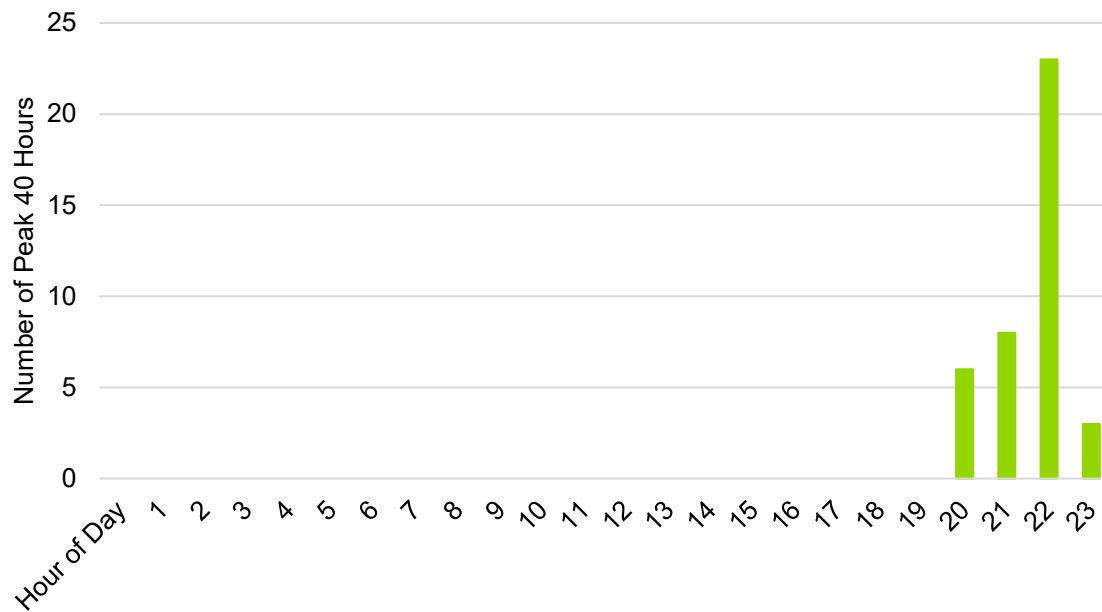


Figure 7 shows the time of day that each of the top 40 demand hours fall in CY34. Note that all peak hours fall between hour 20 and 23 of the day.

# DR Potential Study

Figure 7: Top 40 Hours by Time of Day in CY34



### 3.3.2 Market Characterization

This potential study considers four sectors: residential, commercial, industrial, and EVs. For residential, commercial, and industrial sectors, Guidehouse used the same customer count and load forecasts developed for LUMA’s IRP. For this analysis, Guidehouse used the base scenario from the load forecast. Electric vehicles are treated as a “sector” in this analysis so that the DR potential from EVs can be separately represented. The electric vehicle counts and charging load forecasts used for this analysis to develop EV count and charging demand projections coincident with the peak period use the EV data developed by Guidehouse for LUMA and used for EV-TOU rate filing. To maintain consistency between weekends and weekdays, it is assumed that each year starts on a Friday and ignores the impact of leap years and holidays.

Figure 8 shows the coincident peak demand projections by sector over 20 years. The annual peak demand number represents the average demand over the top 40 system demand hours.

# DR Potential Study

Figure 8: Coincident Peak Demand Forecast by Sector (MW at generator)<sup>10</sup>

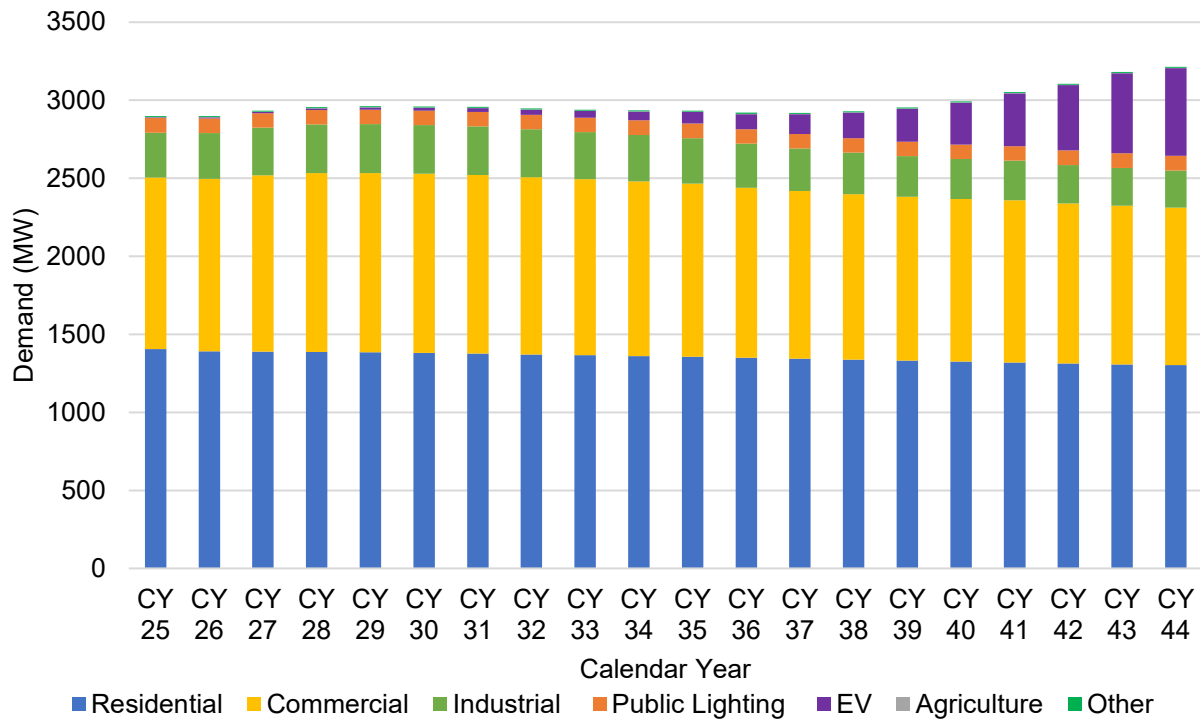
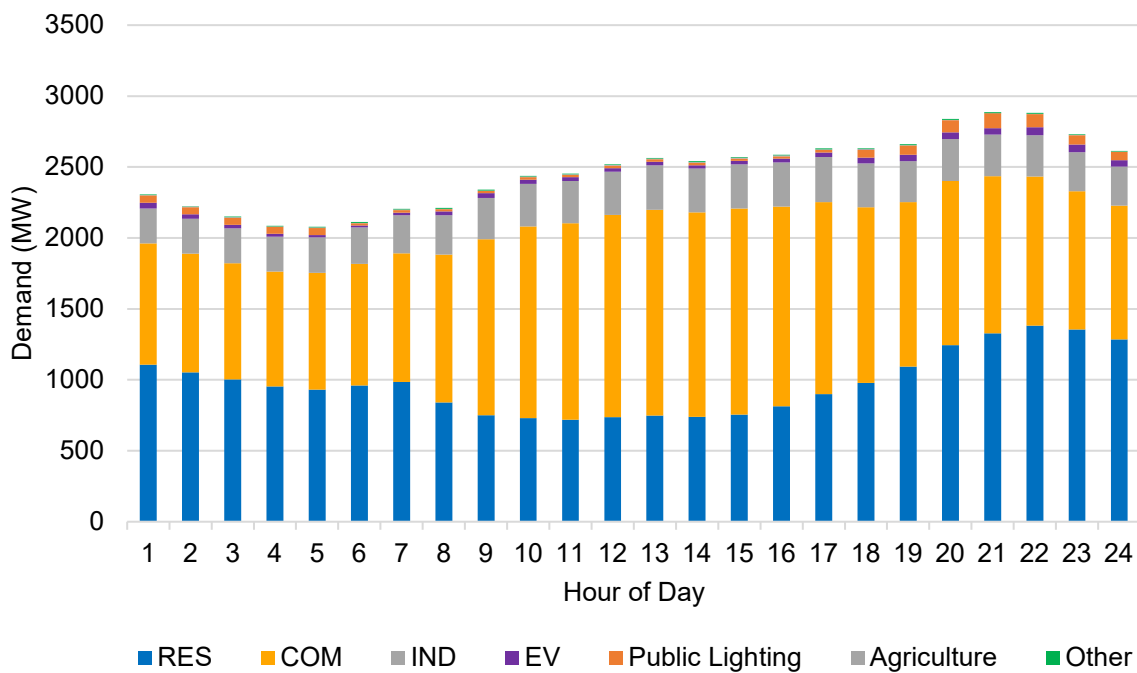


Figure 9 shows the hourly load profile for a representative peak day in CY34 with sectoral contributions to the load.

<sup>10</sup> Figure includes all sectors included in LUMA's load forecast plus EVs. Only residential, commercial, and industrial sectors and EVs are included in the DR potential assessment. Public lighting, agriculture, and other sectors are not included in DR potential assessment.

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Figure 9: CY34 Peak Day Load Profile with Sector Contributions (MW at generator)



The model also uses customer and vehicle count forecasts, as shown in Table 3.

Table 3-2: Customer/Vehicle Count by Sector

Year	Residential	Commercial	Industrial	EVs
CY 2025	1,363,493	123,683	588	12,899
CY 2026	1,363,567	123,705	585	17,031
CY 2027	1,363,792	123,886	582	22,255
CY 2028	1,364,263	124,110	579	29,000
CY 2029	1,364,687	124,270	576	37,873
CY 2030	1,365,033	124,340	573	49,513
CY 2031	1,365,231	124,365	570	64,833
CY 2032	1,365,299	124,261	567	84,790
CY 2033	1,365,287	124,058	564	110,718
CY 2034	1,365,284	123,762	561	144,284
CY 2035	1,365,274	123,389	558	187,538
CY 2036	1,365,222	122,855	555	242,948
CY 2037	1,365,051	122,264	552	313,390
CY 2038	1,364,822	121,663	549	402,077
CY 2039	1,364,539	121,083	546	512,361
CY 2040	1,364,228	120,538	543	647,380
CY 2041	1,363,925	120,116	540	809,503
CY 2042	1,363,629	119,619	537	999,576

## DR Potential Study

Year	Residential	Commercial	Industrial	EVs
CY 2043	1,363,309	119,159	532	1,216,082
CY 2044	1,362,985	118,733	533	1,333,876

For EVs, Guidehouse split the forecast by vehicle class. Guidehouse had previously developed EV adoption forecast numbers for LUMA from 2022 to 2043. This analysis forecast the total electric vehicle population and the associated energy consumption (GWh) from actual 2021 out to 2043. For the purpose of this analysis, these forecasts needed to be split between LDV and MHDV which was achieved with annual split factors for EV population and respective energy needs. In order to develop charging profiles for these two vehicle classes, the analysis used normalized charging shapes using Guidehouse's proprietary Vehicle Analytics & Simulation Tool (VAST)<sup>11</sup>. The VAST outputs provided charging load shapes by vehicle class and type, charging location and also by charger technology. These shapes were aggregated by the two vehicle classes (LDV and MHDV) to develop charging profiles using the EV consumption data. In the absence of Puerto Rico specific market data, Guidehouse had to make certain simplifying assumptions to develop the weighted average charging shapes and consequently the charging profiles for LDV and MHDV classes. The key assumptions were as follows<sup>12</sup>:

- For LDVs, we assumed 70% at-home charging (after work hours) and remaining 30% daytime charging during work hours either at workplace or at public charging stations.
- For MHDVs, 60% of charging is represented by medium duty fleet vehicles, 30% by heavy duty fleet vehicles, 7.5% by transit buses, and 2.5% by school buses.
- All vehicles were assumed to be battery electric vehicles (BEVs) as the load shapes compared to plug-in hybrid electric vehicles (PHEVs) are very similar.
- In terms of powertrains, the normalized charging shape did not vary significantly by charger level and instead varied by vehicle class. Guidehouse used the L2 charger shape as a representative shape for LDVs in SUD, and direct current (DC) charger shape for LDVs in workplaces and all MHDVs.

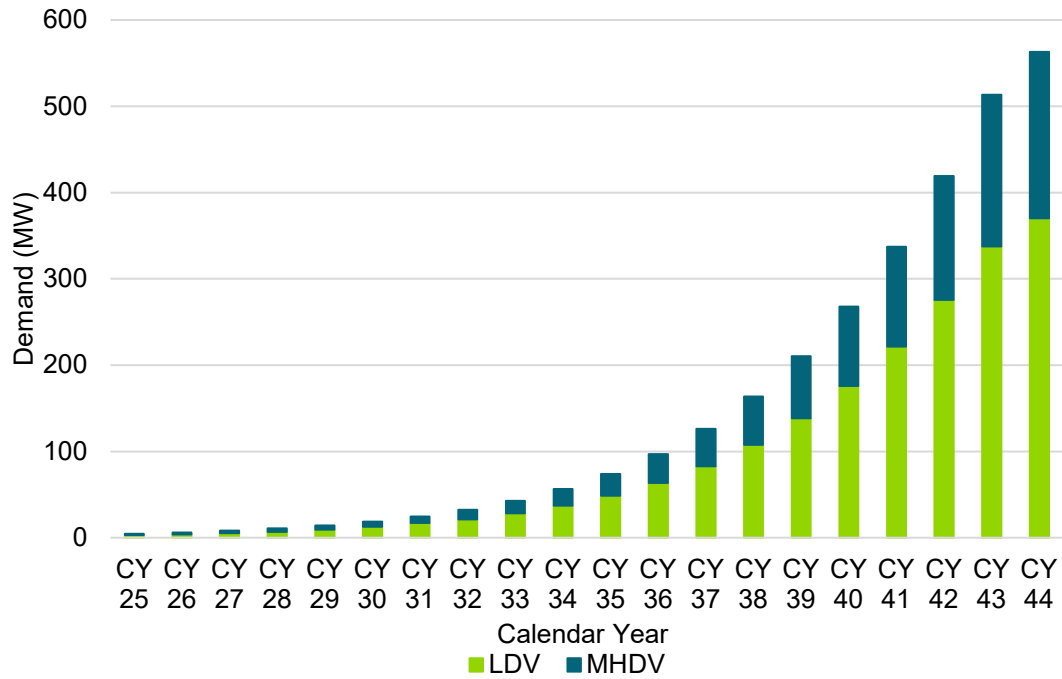
With these simplifications and the energy consumption forecasts Guidehouse was able to develop 8760 charging load profiles for LDVs and MHDVs from 2022 to 2043 that are utilized for the EV DR impact calculations. The coincident peak demand forecast from the two vehicle classes is shown in Figure 10. Since Guidehouse only had access to data up to CY 2043, linear extrapolations were used for CY 2044 values. The projected number of vehicles on the island is shown in Table 4.

<sup>11</sup> Guidehouse developed EV charging profiles for LUMA under a separate EV-related workstream being undertaken by Guidehouse and used for the EV-TOU tariff filing.

<sup>12</sup> These assumptions could be further refined and updated as Puerto Rico field data on these metrics are collected.

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**Figure 10: EV Peak Demand Forecast by Vehicle Type**



**Table 3-3: EV Population Forecast by Vehicle Type**

Year	LDV	MHDV
CY 2025	12,541	358
CY 2026	16,501	530
CY 2027	21,554	701
CY 2028	28,133	867
CY 2029	36,842	1,031
CY 2030	48,293	1,220
CY 2031	63,368	1,465
CY 2032	82,486	2,304
CY 2033	107,710	3,008
CY 2034	140,364	3,920
CY 2035	182,442	5,096
CY 2036	236,347	6,601
CY 2037	304,875	8,515
CY 2038	391,152	10,925
CY 2039	498,439	13,922
CY 2040	629,789	17,591
CY 2041	787,507	21,996
CY 2042	972,416	27,160
CY 2043	1,183,039	33,043
CY 2044	1,297,632	36,244

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## 3.3.3 Participation Hierarchy

The most relevant DR measures for LUMA were chosen as described in Section 3.2. Since multiple DR measures are applicable to the same sector, we considered a hierarchy to stack measures and aggregate DR impacts from these measures to avoid double counting of DR impacts from overlapping DR measures targeting the same sector and end-uses. For example, if residential customers are enrolled in a Critical Peak Pricing (CPP) rate and provide load reductions in response to the CPP event signal, they are not considered eligible for DLC (assuming that CPP and DLC events overlap). Therefore, the participation hierarchy ensures that both DLC and CPP impacts are not considered for the same customer pool since that would amount to double counting of impacts. This is a standard practice to keep accounting simple for aggregation of DR impacts and has been followed in similar potential studies conducted in other jurisdictions. However, the overlap between TOU, which is not event-based and therefore non-dispatchable, and dispatchable event-based DR measures such as DLC and CPP is more nuanced and is described below.

### RESIDENTIAL PARTICIPATION HIERARCHY

The residential participation hierarchy depicted in Figure 11 shows that all eligible residential customers are eligible for TOU rates as the first step in the hierarchy. TOU is not dispatchable (not event-based) and is considered first in the hierarchy. CPP is next in the hierarchy and is placed above DLC. Since the levelized cost of CPP measures is lower than that of DLC measures, CPP was given a higher priority in the hierarchy. This expands the pool of eligible customers for CPP measures and leads to a more cost-effective result. Response to CPP is not restricted to a specific device or end-use equipment and provides opportunities to customers to reduce any of their loads. DLC measures have a higher levelized cost due to the relatively low capacity per controlled device. DLC includes control equipment and connectivity costs since the utility "directly" controls the end-use equipment, whereas for CPP, it is mostly behavioral response to rates, so costs are lower. Additionally, there are no "incentive costs" associated with CPP, unlike DLC, since it is a rate-based or pricing offer to customers.

Following this, the CPP options excludes the TOU participants so as not to double count impacts from both TOU and CPP (since both TOU and CPP impacts are specified as % of the baseline peak demand and therefore we need to exclude TOU participants from CPP eligibility). However, if LUMA were to offer a CPP rate, it would likely open up the offer to both TOU and non-TOU customers and at that time the impacts from CPP for TOU and non-TOU customers would need to be assessed separately and the two groups would have different baselines. TOU customers would have less opportunities to reduce demand during CPP events as some of their demand would have shifted from peak to off-peak periods. In this analysis, we kept the accounting and aggregation of potential simple and did not consider these options.

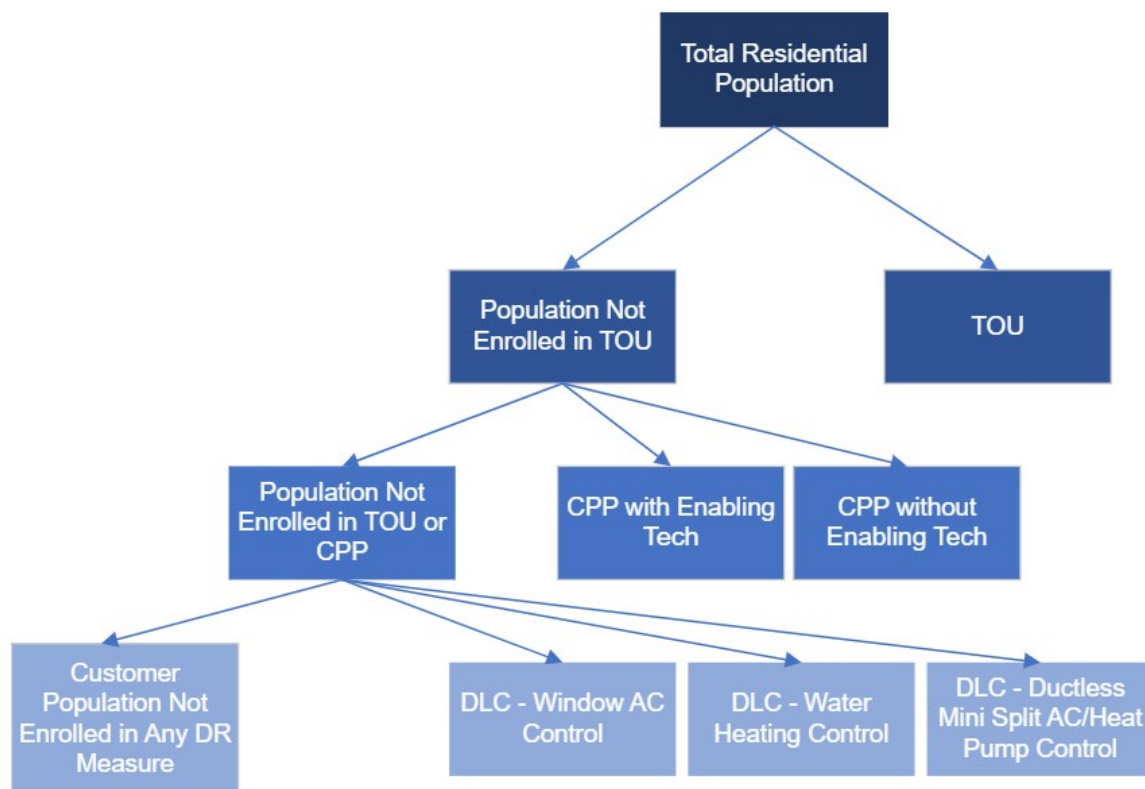
The next step in the hierarchy is DLC, in which residential customers not enrolled in TOU and CPP, are eligible. The exclusion consideration for TOU and DLC is similar to what we discussed above for TOU and DLC. During program design, LUMA likely will consider offering DLC to both TOU and non-TOU customers in which case impacts from these two customer groups will need to be considered separately. However, participation hierarchy with exclusion rules will always apply to dispatchable DR measures that may target same end-uses for the same customer sector (in this example CPP and DLC are both

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dispatchable and therefore same customer cannot provide load reduction for both CPP and DLC if events are called at the same time).

BTM Battery dispatch for residential customers is not included in the hierarchy in Figure 11 below as it does not overlap with the other residential DR measures and can be dispatched independently without double counting of impacts with load reduction measures.

**Figure 11: Residential Participation Hierarchy**

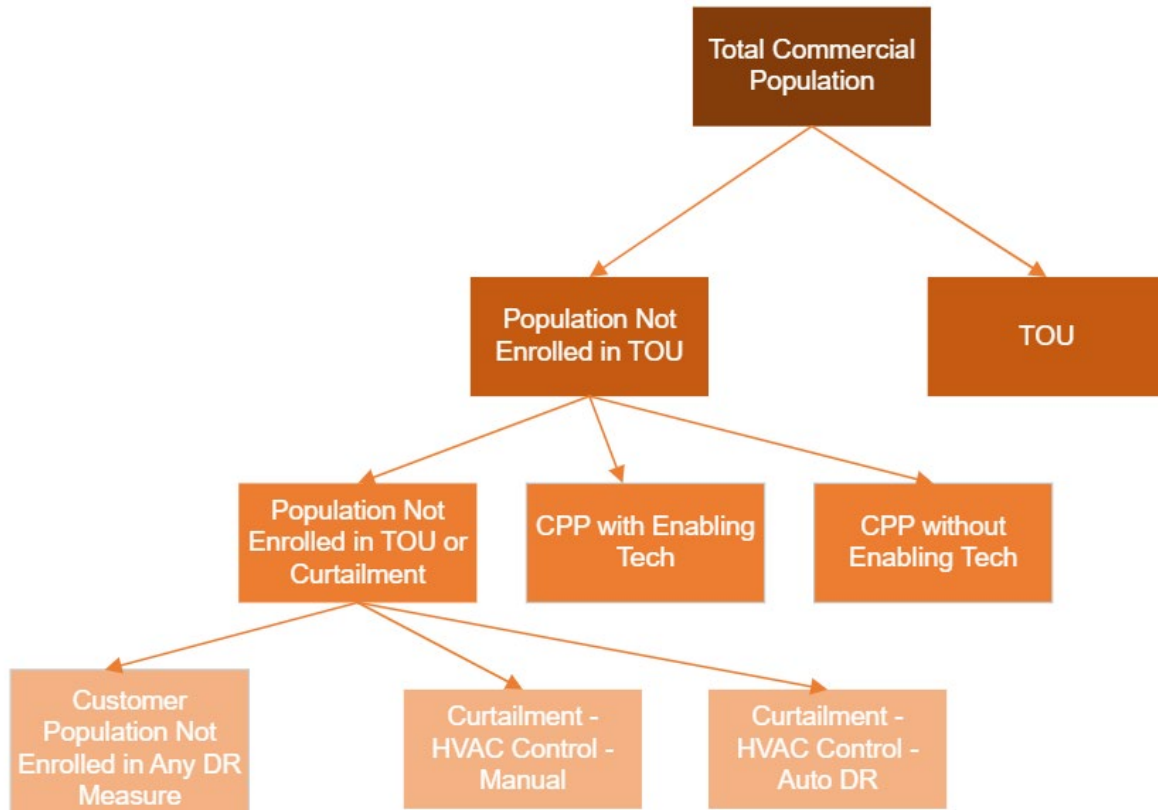


## COMMERCIAL PARTICIPATION HIERARCHY

The commercial participation hierarchy, shown in Figure 12, has similar considerations as residential. It first considers TOU rate offer. Customers not enrolled in TOU are eligible for CPP to keep accounting simple and to avoid double counting of peak reduction impacts from both TOU and CPP. However, during program design, LUMA likely would consider CPP offer to both TOU and non-TOU customers, and therefore CPP impacts from these two groups will need to be accounted for separately. Lastly, customers not enrolled in either TOU or CPP are considered eligible for C&I curtailment options (manual and Auto-DR). The exclusion rule between TOU and Curtailment is for accounting simplicity and avoid double-counting. During program design, however, LUMA will likely offer C&I Curtailment measures to both TOU and non-TOU customers and the load reduction impacts from these two groups will need to be accounted separately. However, participation hierarchy is always valid for multiple event-based dispatchable DR measures that may target same end-uses (in this example CPP and C&I Curtailment measures are both dispatchable and therefore same customer cannot provide load reduction for both CPP and C&I Curtailment if events are called at the same time).

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Figure 12: Commercial Participation Hierarchy

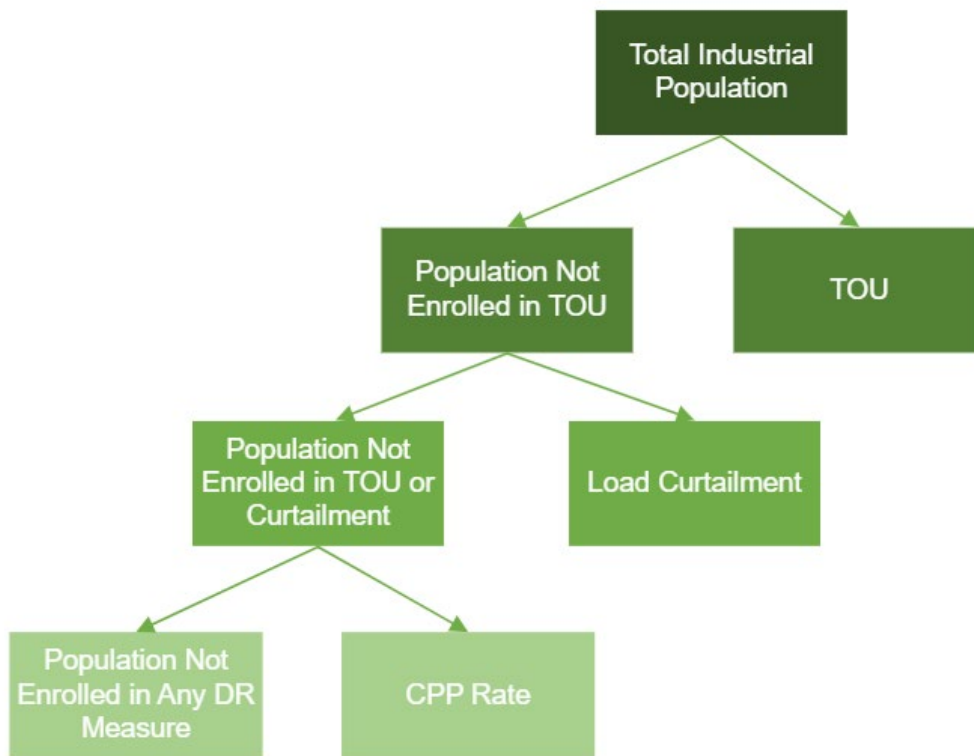


## INDUSTRIAL PARTICIPATION HIERARCHY

Figure 13 shows the industrial participation hierarchy. TOU is considered first in the hierarchy followed by load curtailment and CPP. The overlap considerations for industrial are similar to those discussed above for residential and commercial customers. The hierarchy excludes customers enrolled in TOU from CPP and Curtailment for accounting simplicity and to avoid double counting of impacts, although, during program design, LUMA likely will offer CPP and Curtailment to both TOU and non-TOU customers. However, customers eligible for Curtailment and CPP need to be mutually exclusive since both are event-based and dispatchable and therefore load reduction from customers from both measures cannot be double counted.

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Figure 13: Industrial Participation Hierarchy

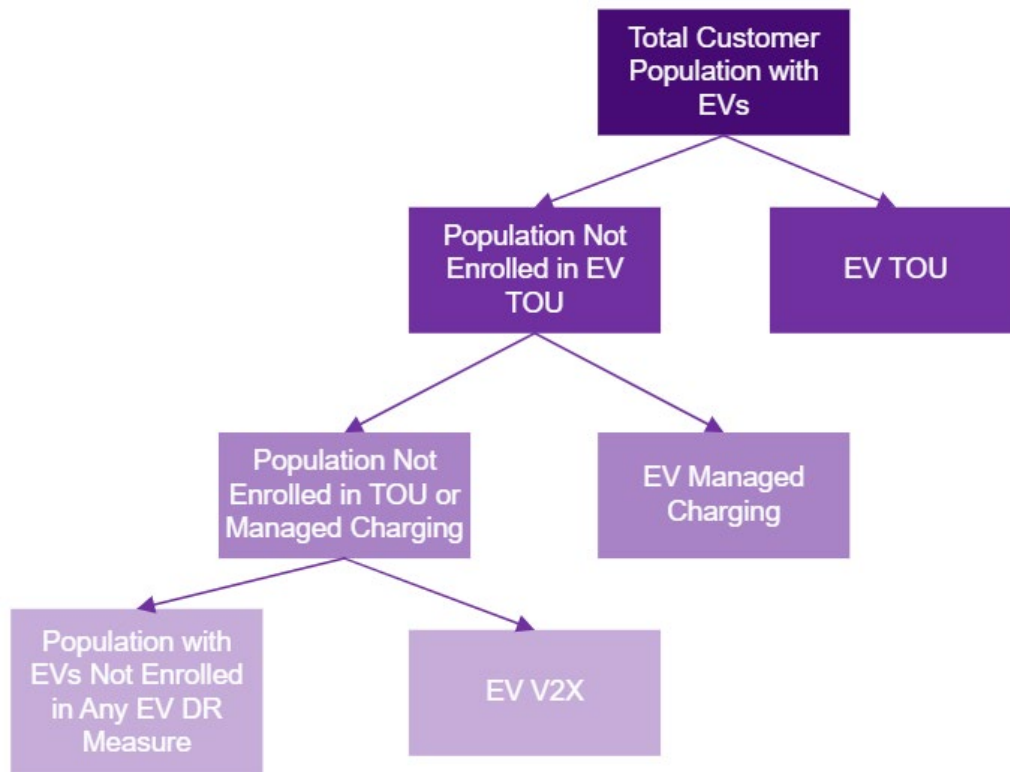


## EV PARTICIPATION HIERARCHY

The EV participation hierarchy is separate from the other sectors, and its organization is shown in Figure 14. All corresponding EV populations (LDVs for residential, MDHDVs for commercial) are eligible for TOU rates. The population that is not enrolled in EV TOU is then eligible for managed charging, and its participants are excluded from the final step in the hierarchy, EV V2X.

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Figure 14: EV Participation Hierarchy



It is important to note that this study has generally taken a conservative approach to the participation hierarchies. Further refinement in the program design stage could enable customer participation in more than one measure and, hence, some overlap between measures. This refinement could lead to higher DR impacts but calculating the interactive effects across measures is very complicated.

### 3.3.4 Potential Estimation Approach

The key inputs for DR potential estimation are assumptions on participation rates in DR measures (specified either as “% of number of eligible customers” or “% of eligible load”) and unit impacts (which represents per participant load reduction expressed as either “kW reduction per customer/device” or as “% reduction in coincident peak demand”). The manner in which these are specified can vary by type of DR measure. The assumptions for each measure are described for residential, commercial, industrial, and EV sectors in Sections 3.4, 3.5, 3.6 and 3.7 respectively.

The basic calculation to determine demand response potential is shown in Equation 1.

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## Equation 1: Demand Response Potential Equation

$$\text{Demand Reduction (MW)} = \text{Participation (\%)} * \text{Impact (\%)} * \text{Eligible Customers} * \frac{(\text{Average Load Top 40 Hours (MW)})}{(\text{Total Customers})}$$

These variables are further described below.

The eligible customers represent the fraction of the sector/segment population or the total load to which a certain measure applies. For example, for window AC control, it represents the fraction of customers with window AC. The participation % represents the fraction of eligible customers/load that enroll in a DR program and participate in DR events when called.

The participation % is comprised of the control strategy eligibility (variable), steady-state participation (static), and participation ramp (variable). The control strategy eligibility represents the fraction of the eligible customers that are controllable through the adoption of a smart device. In the above window AC load control example, this would represent the fraction of customers with window AC that either have a smart thermostat or a smart switch for control of the cooling load during DR events. The steady-state participation represents the enrollment percentage in a program after the program matures and is not actively growing and recruiting new customers/load. We assumed that a program ramps up to full participation or steady-state participation in a certain number of years after initiation. The participation ramp refers to the slope at which the program is growing from inception to full maturity. The ramp reaches 100% after the program reaches maturity or the steady state participation level. For example, a program could reach 30% steady-state participation from inception to maturity following a S-shaped curve in 5 years.

The impact % represents the load reduction per customer as a percentage of that customer's coincident demand. The coincident demand is represented by the last variable in the equation above, which is the average coincident load per customer (in this case it is the average load over the top 40 system peak demand hours).

These assumptions for the DR measures included in this study are based on the Guidehouse team's extensive experience conducting similar studies for several clients across the U.S. To the extent possible based on the available data, we used Puerto Rico specific data. These assumptions would need to be updated as Puerto Rico collects baseline study and has experience with DR pilots. As stated previously, these assumptions are described in detail in Sections 3.4, 3.5, 3.6 and 3.7.

### 3.3.5 Framework for Estimating Demand Response Costs

Demand response measure costs are commonly represented as levelized costs on a \$/kW-year basis – representing the cost for one kW of effective capacity for one year – to facilitate comparison with traditional supply-side resources for which capacity costs can also be expressed on the same basis. Given that the results from this study will serve as an input to LUMA's IRP, Guidehouse has used a \$/kW-year costing metric for the various demand response measures included in the study. All costs in this report are expressed in 2023 real dollars.

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Expressing the cost of all demand response measures on a uniform \$/kW-year basis also facilitates comparison between demand response measures. For example, some DR measures include up-front incentives that are typically amortized over the life of the measure (or the participant's expected tenure in the DR program), whereas other measures, such as TOU rates, don't include incentives per se, but do require investments in marketing and communications to inform potential participants of the TOU rates.

The levelized cost assumptions included in this analysis includes various upfront and recurring fixed and variable costs. The biggest cost component in running DR programs are incentives offered to customers that may consist of both upfront and recurring incentives. Upfront incentives are for a customer to sign up for a DR program, while recurring incentives are for their ongoing participation in the program and for responding to DR events when called. The pricing measures that represent time-varying rates (TOU and CPP) do not offer separate incentives to customers and therefore these do not have any associated incentive costs. The non-incentive costs consist of the following components –program development costs, which are a one-time cost incurred at the time of program set up and cover both technology and labor costs incurred at that stage; marketing and recruiting costs for customers to enroll in a DR program; ongoing operations and maintenance costs, that typically represents device connectivity and control costs; recurring labor and materials costs for program administration; and payments to third-party service providers in cases where the program delivery is contracted out to third-parties. The levelized costs used in this assessment do not include AMI costs or DRMS/DERMS costs. These also do not include any participant opportunity costs or hassle costs associated with participation in DR programs.

GH has supported numerous utilities in the evaluation of DR programs and the estimation of DR potential across their service territories. The cost estimates for the most relevant DR measures for Puerto Rico were informed by this wealth of knowledge gained through GH's past work with other utilities on DR as well as our knowledge of the Puerto Rican market gained from our previous work with LUMA, such as on the EE/DR Transition Period Plan.<sup>13</sup>

LUMA and Guidehouse have observed that many costs in Puerto Rico are generally higher than those on the mainland and expects that this will also hold true for many of the DR measures. To reflect these higher costs, Guidehouse has included a Puerto Rico cost adder of 20% to the current or projected "mainland costs" for similar DR measures based on our experience that costs in Puerto Rico are higher than costs on the mainland. As LUMA gains experience with various DR measures, the Puerto Rico cost adder can be removed or revised, and the measure costs can be based directly on local experience.

Another costing consideration is whether a DR measure is mature or "emerging". Costs for mature DR measures are more robust and have much less uncertainty than those for emerging DR measures because there is a relatively large cost dataset for mature measures. For example, DLC of Central Air Conditioners is a mature DR measure that has been deployed widely across the mainland. Accordingly, the costs for this measure are relatively robust and consistent across programs. On the other hand, there is significantly less cost data available for emerging measures. Additionally, emerging measures have not yet benefited from the same scale and experience curve effects as mature DR measures. For example, V2X DR measures are emerging and there is limited "at scale" experience with these measures given the state of technology and limited population of EVs.

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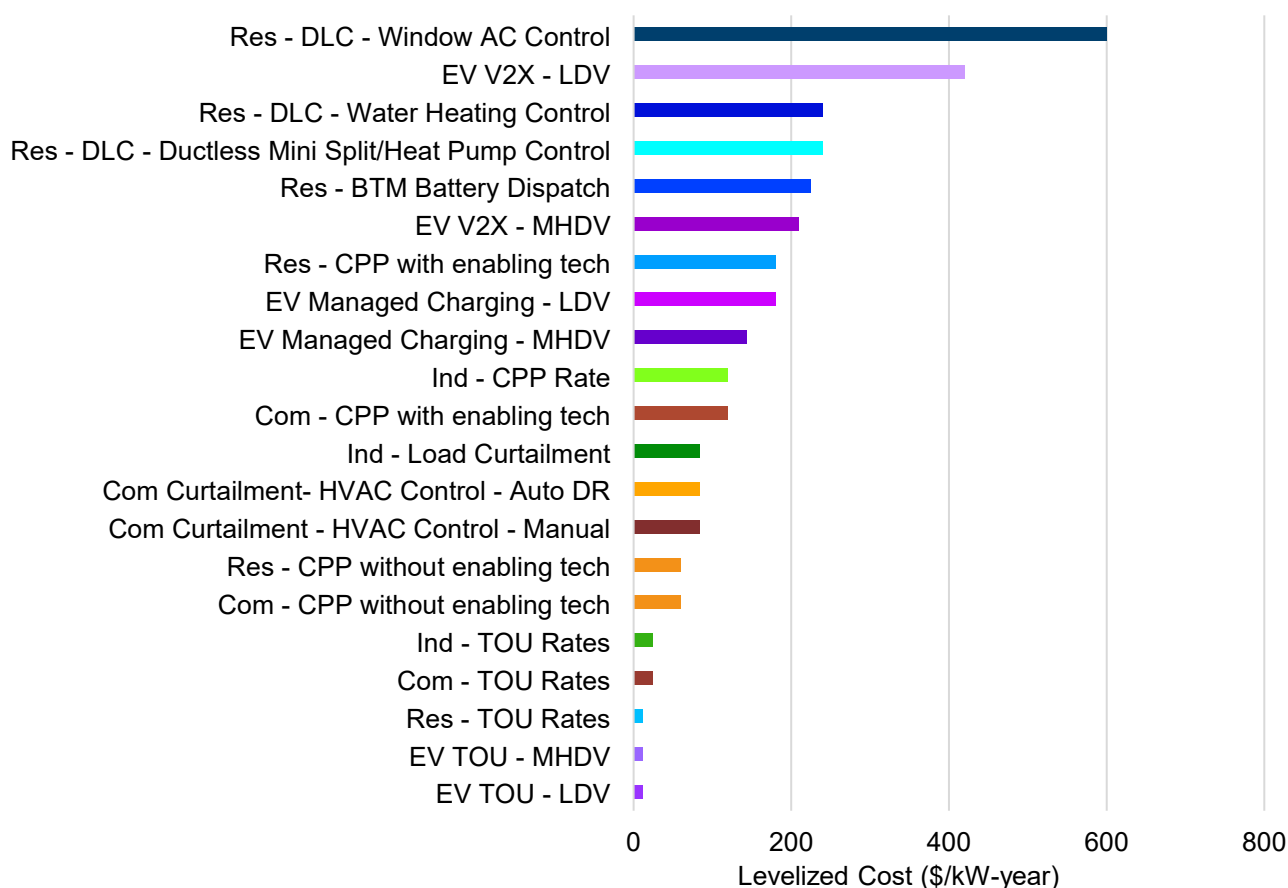
<sup>13</sup> This study assumes that AMI is coming from a different pool of costs.

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While it is reasonable to assume that the costs for emerging DR measures will decline over time, Guidehouse has not included any cost reductions for emerging technologies in this study for conservatism. We recommend that LUMA continue to monitor developments for those DR measures – such as V2X – that are expected to provide significant DR capacity in the longer term and to adjust the cost estimates for these measures as new information becomes available.

Based on the approach and considerations described above, the cost estimates for the most relevant DR measures are provided in Figure 15 below. These values include the 20% Puerto Rico Cost Adder discussed previously. Unless otherwise noted all costs in this report are real 2023 \$.

**Figure 15: Levelized Cost by Measure (\$/kW-year)**



As shown in Figure 15, most of the rate-related DR measures such as TOU rates and dynamic pricing have relatively low costs because 1) the cost of the AMI infrastructure necessary to enable TOU and dynamic pricing has not been included, 2) the cost of marketing and communication for the new rate offerings is spread across all participating customers, and 3) there are no separate incentive costs associated with time-varying rates. One exception to this is the residential critical peak pricing with enabling technology because this measure typically includes an incentive to customers for the enabling technology.

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Among the measures with the highest costs, it is worth noting that V2X is an emerging technology whose costs will likely decline over time as technology matures and the population of EVs increases. As noted, Guidehouse recommends that LUMA continue to monitor developments for V2X, and other emerging DR measures, and to adjust the cost estimates for these measures as new information becomes available. Another relatively high-cost measure – DLC of window air conditioners – is also emerging, but a key cost driver for this measure is the relatively limited savings available from each window air conditioner. While there may be some reductions in the cost of this measure as more window air conditioners with suitable technology are deployed, the saving per unit will not change materially and, absent a technology breakthrough, this measure will likely continue to have relatively high costs well into the future.

### 3.4 Residential Demand Response Assumptions

The relevant measures for residential customers are the two time-varying rates or pricing options – Time-Of-Use rate and Critical Peak Pricing rate, AC load control measures (window and split AC control), water heating control, and dispatch of BTM batteries during DR events. These are briefly described below with assumptions used for potential and cost calculations.

#### 3.4.1 Residential TOU Rates

A summary of the Residential TOU Rates is provided in Table 5. This table states the key assumptions for potential and cost calculations for this measure as described previously in Sections 3.3.4 and 3.3.5. Additional description of the TOU rate is presented after the table.

**Table 3-4: Residential TOU Rates Overview**

Item	Description
<b>Overview of Residential TOU Option</b>	<ul style="list-style-type: none"> <li>Voluntary opt-in residential TOU rate, which has predetermined prices for on and off-peak hours that incentivize residential customers to shift load from peak to off-peak periods.</li> <li>Three-tiered TOU rate with peak to off-peak ratio of 1.7 <i>(please refer to detailed description of the rate following this table).</i></li> </ul>
<b>Eligible Customers</b>	<ul style="list-style-type: none"> <li>All residential customers are eligible.</li> </ul>
<b>Participation assumptions</b>	<ul style="list-style-type: none"> <li>Steady state participation is 20% of eligible customers in the residential segment.<sup>14</sup></li> <li>A S-shaped ramp for participation begins from CY29 onwards following AMI deployment, reaching 100% ramp (reaches steady-state participation of 20%) for eligible customers by CY35.</li> </ul>

<sup>14</sup> Represents participation levels in mature programs after an option is fully ramped up.

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Item	Description
<b>Unit Impacts</b> <sup>15</sup>	<ul style="list-style-type: none"> <li>6% reduction in coincident peak demand<sup>16</sup>.</li> </ul>
<b>Levelized Costs</b>	<ul style="list-style-type: none"> <li>\$12/kW-yr. levelized cost<sup>17</sup></li> </ul>
<b>Incentive Splits</b> <sup>18</sup>	<ul style="list-style-type: none"> <li>0% incentive split since this is a rate-based measure, 100% non-incentive split</li> </ul>

The Residential TOU rates used for this study were structured similarly to, and based on the same underlying assumptions as, the Interim EV TOU rates that were proposed by LUMA in its September 1, 2022 Motion<sup>19</sup> and approved by the Energy Bureau in its January 13, 2023 Resolution and Order<sup>20</sup>. Accordingly, the key structural features of the residential TOU rates used for this study are as follows:

- 3-part pricing applicable on all days (including holidays and weekends):
  - Off-Peak period roughly coincident with period of maximum solar PV output,
  - Shoulder period, and
  - On-Peak period roughly coincident with the period of highest system demand.
- 1.7:1 Ratio of On-Peak to Off-Peak rates
- TOU rate only applies to the Fuel Charge Adjustment (FCA) and Purchased Power Charge Adjustment (PPCA) component of the bill. The FCA and PPCA in effect in Q2, 2023 were used in determining the rates.
- TOU rates are revenue neutral for FCA and PPCA based on residential load profile (i.e., the average residential customer will pay the same under base rate and TOU rate absent any behavior change due to the TOU rates).

The residential load profile is different than the estimated residential EV charging profile used to derive the proposed Interim EV TOU rates. Accordingly, given the above requirement for revenue neutrality in

<sup>15</sup> Impact assumption is based on The Brattle Group research further described in the TOU rate description below.

<sup>16</sup> The coincident peak demand is based on residential hourly load data for Puerto Rico and the peak period definition described in Section 3.3.1 and is estimated using the market characterization approach described in Section 3.3.2

<sup>17</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

<sup>18</sup> This represents the incentive and the non-incentive fractions/shares in the total levelized cost.

<sup>19</sup> NEPR-MI-2021-0013, The Deployment of Electric Vehicle Charging Infrastructure, Motion Submitting Draft Phase I EV Plan and Request to Postpone Compliance Technical Hearing No.3 and Concomitant Deadline to Submit Revised Phase I EV Plan September 1, 2022 and Motion Re-Submitting Exhibit 1 Filed on September 1, 2022 with Technical Repairs and Requesting Substitution of Original Exhibit, September 2, 2022.

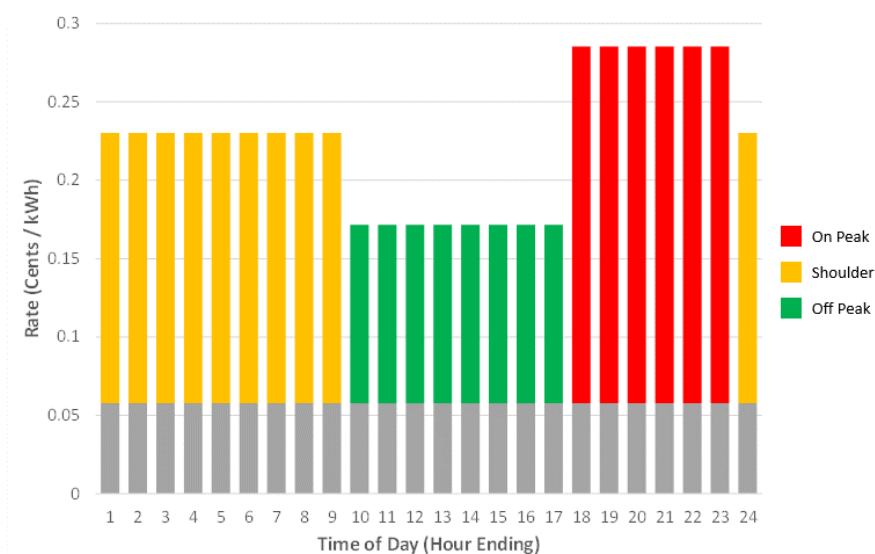
<sup>20</sup> NEPR-MI-2021-0013, The Deployment of Electric Vehicle Charging Infrastructure, Draft Phase I EV Plan and Revised EV Rate Design, January 13, 2023.

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deriving the Residential TOU rate, the relative pricing in each of the three TOU periods is slightly different than for the Interim EV Rates.

The resultant Residential TOU rates derived based on the above approach and used in this study are provided in Figure 16. As shown, the all-in Residential TOU rate varies from a low of just over 17 cents / kWh for the mid-day Off-peak Period to just over 28 cents / kWh for the evening On-Peak period high.

**Figure 16: Residential TOU Rates Used in Study**



The individual components of the residential TOU rate are as follows:

**Table 3-5: Residential TOU Rate Components**

Rate Component (\$ / kWh)	Off-Peak	Shoulder	On-Peak
<b>Time-varying FCA &amp; PPCA</b>	0.11	0.17	0.23
<b>Other Rate Components (non-time-varying)</b>	0.06	0.06	0.06
<b>Total "All-in" Rate</b>	<b>0.17</b>	<b>0.23</b>	<b>0.29</b>

For the purposes of estimating the reduction in residential load and system peak due to the Residential TOU rates, Guidehouse used the ratio of the all-in price during the On-Peak period to the all-in price during the Off-Peak period. Based on the all-in rates shown in Table 6, this key ratio for Residential TOU rates is 1.7. While future costs and rates will differ from that shown above and used in the Guidehouse analysis, if the relative contribution of the FCA and PPCA to the all-in price remains roughly the same, and the On-Peak FCA and PPCA component of the residential rate continues to be twice that of the Off-Peak component, then this key ratio of 1.7 based on the all-in rates will remain relatively stable and the findings would still be applicable under different cost and rate assumptions. However, if a greater proportion of the residential rate were made to be time-varying, then the ratio would likely increase, and

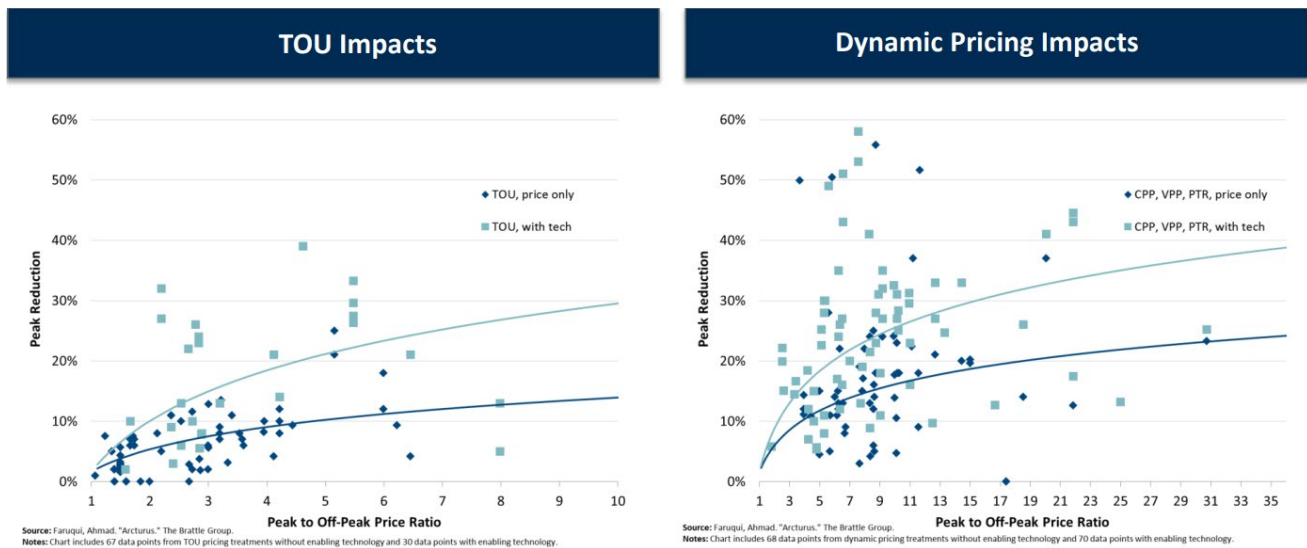
# DR Potential Study

the resultant peak demand impacts would be understated. Conversely, if the relative contribution of the FCA and PPCA to the residential rate decreased, then the ratio would decrease, and the resultant peak demand impacts would be overstated. Nonetheless, Guidehouse believes that using an On-Peak/Off-Peak all-in rate ratio of 1.7 based on the assumptions stated provides a robust mid-point estimate for use in estimating peak demand reductions due to residential TOU rates.

Based on information provided by LUMA, Guidehouse has assumed that TOU rates would be initially offered to residential (as well as commercial and industrial customers) in 2028 following the deployment of the AMI.

Based on a compilation by the Brattle Group of TOU impacts drawn from various TOU implementations and pilots<sup>21</sup>, Guidehouse estimates that the peak demand reduction from a 1.7 On-Peak / Off-Peak price ratio will be approximately 6%. This is based on the midpoint between the “TOU price only” line and the “TOU, with tech” line in the chart on the left side of Figure 17. Guidehouse chose the midpoint between the two lines based on the assumption that some TOU participants will be “technology-enabled” whereas others will not.

**Figure 17: Peak Demand Reduction for Varying TOU and Dynamic Price Ratios**



Source: “Dynamic Pricing & Demand Response”; presented to IPU’s Annual Regulatory Studies Program by The Brattle Group; August, 2016<sup>22</sup>

<sup>21</sup> Dynamic Pricing & Demand Response, Presented to: IPU’s Annual Regulatory Studies Program: The Fundamentals Course, Lansing, Michigan, Ahmad Faruqui, Ph. D. (with Sanem Sergici), August 11, 2016

<sup>22</sup> [https://www.brattle.com/wp-content/uploads/2017/10/5760\\_dynamic\\_pricing\\_and\\_demand\\_response.pdf](https://www.brattle.com/wp-content/uploads/2017/10/5760_dynamic_pricing_and_demand_response.pdf)

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## 3.4.2 Residential Critical Peak Pricing

A summary of the Residential CPP rate is provided in Table 7. This table states the key assumptions for potential and cost calculations for this measure as described previously in Sections 3.3.4 and 3.3.5. Additional description of the CPP rate is presented after the table.

**Table 3-6: Residential Critical Peak Pricing Overview**

Item	Description
<b>Overview of Residential CPP Option</b>	<p>The CPP rate includes a significantly higher rate during DR event periods (referred to as the Critical Peak Period – CPP) than the customer’s Otherwise Applicable Tariff (OAT) that signals the customer to reduce load during the CPP event period. The rate in non-CPP hours in a CPP tariff is lower than a customer’s OAT, which incentivizes the customer to reduce load during the critical peak periods. Unlike a TOU rate, a CPP rate is event-based and dispatchable. It is typically offered as a voluntary opt-in rate.</p> <p>Customers can respond to the CPP signals either by manually reducing load during the CPP event (referred to as “CPP without enabling technology”) or their response could be automated using enabling technology such as smart thermostats (referred to as “CPP with enabling technology”).</p> <p>Critical peak to off-peak ratio: 6.16 for both CPP measures  <i>(please refer to detailed description of the rate following this table).</i></p>
<b>Eligible Customers</b>	<ul style="list-style-type: none"> <li>All residential customers not enrolled in TOU (based on hierarchy).</li> <li>The control strategy eligibility split between these two measures is 46% for CPP without enabling tech and 54% for CPP with enabling tech.<sup>23</sup></li> </ul>
<b>Participation Assumptions</b>	<ul style="list-style-type: none"> <li>Steady state participation is 20% of eligible customers in the residential segment.</li> <li>An S-shaped ramp for participation begins in CY29 with the availability of AMI, reaching 100% ramp (with participation level at 20%) for eligible customers by CY34 for both CPP measures</li> </ul>

<sup>23</sup> The 54% saturation assumption is based on the assumed cooling saturation for room AC and ductless mini split ACs. Customers with these end-use equipment are eligible for “CPP with enabling technology” as these equipment can be potentially controlled using smart thermostats during DR events. The residential HVAC DLC section further describes the basis for the 54% of the AC saturation assumption for residential customers.

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Item	Description
<b>Unit Impacts<sup>24</sup></b>	<ul style="list-style-type: none"> <li>Residential CPP without enabling tech: 10% of total facility load for eligible customers.</li> <li>Residential CPP with enabling tech: 20% of total facility load for eligible customers.</li> </ul>
<b>Levelized Costs</b>	<ul style="list-style-type: none"> <li>Residential CPP without enabling tech: \$60/kW-yr.<sup>25</sup></li> <li>Residential CPP with enabling tech: \$180/kW-yr.<sup>26</sup></li> </ul>
<b>Incentive Splits</b>	<ul style="list-style-type: none"> <li>Residential CPP without enabling tech: 0% incentive split since this is a rate-based measure and therefore there are no separate incentives to customers for enrolling and responding to CPP events, 100% non-incentive split.</li> <li>Residential CPP with enabling tech: 70% incentive split which represents the one-time enabling technology costs offered to customers at the time of enrollment to provide enhanced response to CPP events, 30% non-incentive split.</li> </ul>

The Residential CPP rates used for this study followed a similar approach as described above for the Residential TOU rates:

- CPP rate only applies to the FCA and PPCA component of the bill. The FCA and PPCA in effect in Q2, 2023 were used in determining the CPP rates.
- CPP rates are revenue neutral for FCA and PPCA based on residential load profile (i.e., the average residential customer will pay the same under base rate and CPP rate absent any behavior change due to the CPP rates).

The key differences between the Residential CPP and TOU rates are:

- The CPP rate only applies during the top 40 demand hours of the year that fall under the peak period as defined in Section 3.3.1 (with the remaining 8720 hours of the year being the “Base” rate).
- A 6.16:1 ratio between the CPP and Base rate based on experience elsewhere.

<sup>24</sup> Impact assumption is based on The Brattle Group research further described in the CPP rate description below. These impact %s are applied to the coincident peak demand. The coincident peak demand is based on residential hourly load data for Puerto Rico and the peak period definition described in Section 3.3.1 and is estimated using the market characterization approach described in Section 3.3.2

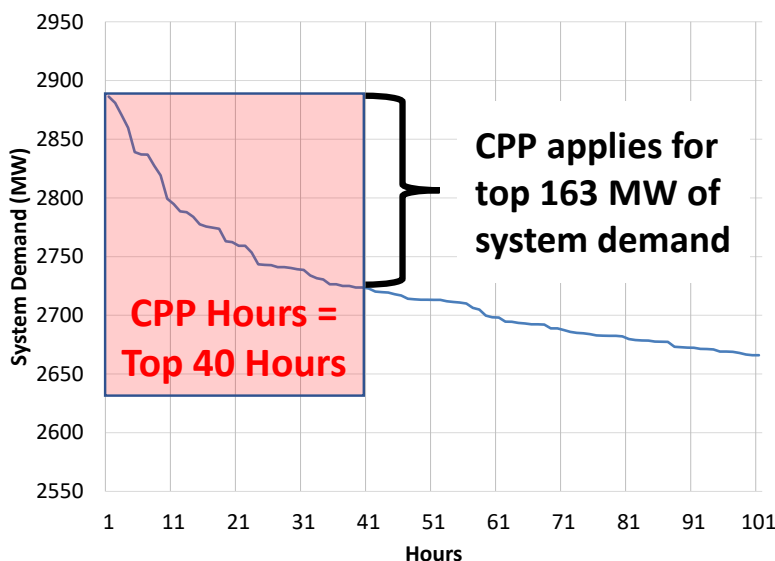
<sup>25</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

<sup>26</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

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A duration curve of system demand (based on the CY34 forecast) with demand sorted from highest to lowest is provided below to illustrative how the CPP rate focusses on the hours with highest system demand. As shown, the system demand ranges between approximately 1500 MW and 2900 MW throughout the year. Zooming into the portion of the duration curve representing the top 100 hours as provided within Figure 18 shows that the CPP rate would only apply in the top 40 hours when system demand exceeds approximately 2720 MW. In other words, based on the CY34 forecast, the CPP rate would be applicable whenever system demand is within 160 MW (or roughly 6%) of the forecast system peak demand.

**Figure 18: System Duration Curve – top 100 hours**



Further analysis of the CY34 forecast data shows that there are expected to be 17 days with CPP hours (top 40 hours) in them. The breakdown of CPP event duration is as shown below in Table 8. CPP events are expected to range from 1 – 4 hours duration as shown. The Guidehouse analysis focused only on the top 40 hours, but some CPP programs have fixed duration CPP events (rather than the variable duration assumed by Guidehouse in the analysis). As shown in Table 8, using a four-hour fixed duration CPP event for any hour that falls into the top 40 system demand hours would increase the number of CPP hours to 68. Guidehouse believes both designs – variable or fixed CPP duration – would be attractive to some customers and both are reasonable and viable design alternatives. Customers would be provided day-ahead notification of CPP events.

**Table 3-7: Frequency and Duration of CY34 CPP Events (based on CY34 Forecast)**

CPP Event Duration	# of Days	Event-hours	If all CPP Events were 4 hours in duration
1 hour	5	5	20
2 hours	4	8	16
3 hours	5	15	20
4 hours	3	12	12
<b>Total</b>	<b>17</b>	<b>40</b>	<b>68</b>

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Given the residential load profile and requirement for revenue neutrality for collection of FCA and PPCA under the CPP, the resultant residential CPP rate components are shown in Table 9.

**Table 3-8: Residential CPP Rate Components**

Rate Component (\$ / kWh)	Critical Peak Period	Base Rate (all other hours)
<b>Time-varying FCA &amp; PPCA</b>	1.26	0.16
<b>Other Rate Components (non-time-varying)</b>	0.06	0.06
<b>Total "All-in" Rate</b>	<b>1.32</b>	<b>0.22</b>

The Base Rate for the Time-varying FCA and PPCA of 15.7503 cents / kWh is 9% lower than the standard rate of 17.2249 cents / kWh that would apply to all hours if the customer does not enroll in the CPP rates.

Similarly, as for Residential TOU rates, Guidehouse used the ratio of the all-in price during the CPP period to the all-in price during the Base rate period to determine the % demand reduction during CPP events. Based on the all-in rates shown in Table 9, this key ratio for Residential CPP rates is 6.1. While future costs and rates will differ from that shown above and used in the Guidehouse analysis, if the relative contribution of the FCA and PPCA to the all-in price remains roughly the same, and the FCA and PPCA component of the residential rate during Critical Peak Periods continues to be eight (8) times that of the FCA and PPCA component during the Base period, then this key ratio of 6.1 will remain relatively stable and the findings would still be applicable under different cost and rate assumptions. Guidehouse believes that using an CPP all-in rate key ratio of 6.1 based on the assumptions stated provides a robust mid-point estimate for use in estimating peak demand reductions due to residential CPP rates. Based on information provided by LUMA, Guidehouse has assumed that TOU rates would be initially offered to residential (as well as commercial and industrial customers) in 2028 following the deployment of the AMI.

Experience with CPP rates demonstrates there is a significant difference in response between customers who are “technology-enabled” and those who are not. “Technology-enabled” simply refers to any technology that automates the customer response to the CPP price signal. For example, this could be a smart thermostat that adjusts the thermostat set point automatically during CPP events or smart water heater that defers water heating until after the CPP event. Demand reduction from customers who are technology-enabled is generally at least twice that of comparable customers without technology to respond automatically to the CPP price signal. The only drawbacks to “technology-enabled” CPP are that 1) it is more expensive – utilities typically have to provide some sort of incentive for the enabling technology – and 2) it doesn’t apply to all customers because of their equipment stock. Guidehouse has estimated demand impacts for both scenarios and has assumed a mix of technology-enabled and non-enabled customers participating in the CPP.

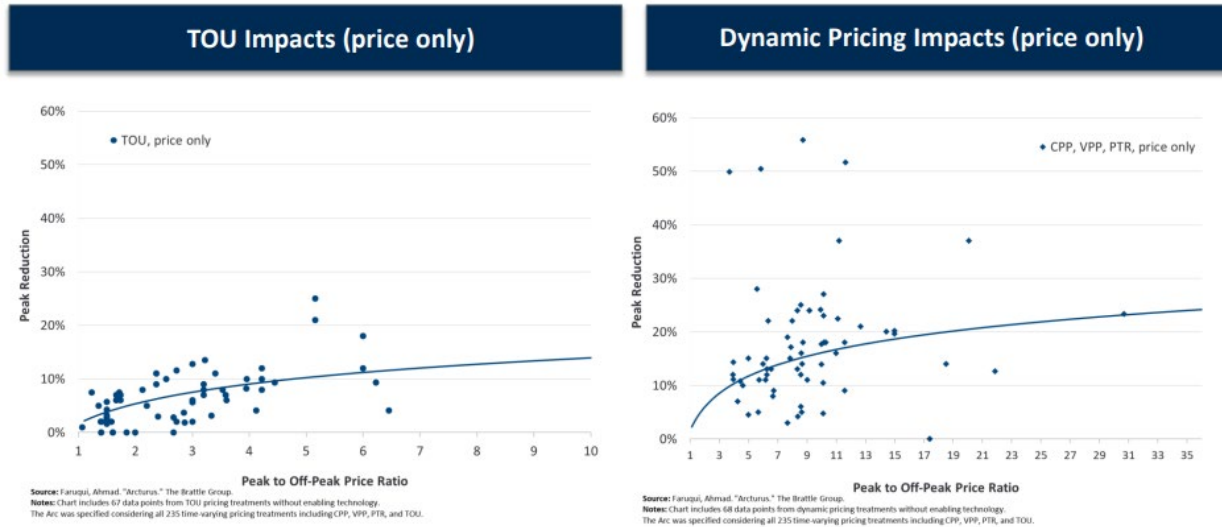
Based on a compilation by the Brattle Group of dynamic price impacts drawn from various dynamic price implementations and pilots<sup>27</sup>, Guidehouse estimates that the peak demand reduction from a 6.1 CPP /

<sup>27</sup> Dynamic Pricing & Demand Response, Presented to: IPU’s Annual Regulatory Studies Program: The Fundamentals Course, Lansing, Michigan, Ahmad Faruqui, Ph. D. (with Sanem Sergici), August 11, 2016

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Base rate price ratio will be approximately 10% for customers that are not “technology-enabled” and 20% for customers that are “technology-enabled.” This is based on the chart on the right side of Figure 19.

**Figure 19: Peak Demand Reduction for Varying TOU and Dynamic Price Ratios**



Source: “Dynamic Pricing & Demand Response”; presented to IPU’s Annual Regulatory Studies Program by The Brattle Group; August, 2016<sup>28</sup>

### 3.4.3 Residential HVAC Direct Load Control

A summary of the Residential HVAC Direct Load Control measure is provided in Table 10. This table states the key assumptions for potential and cost calculations for this measure as described previously in Sections 3.3.4 and 3.3.5. These assumptions are based on best available data sources and would need to be updated based on actual baseline data for Puerto Rico, when available.

A key assumption used to estimate potential for this measure is the saturation of window AC and split AC units among residential customers in Puerto Rico. Guidehouse used the following assumptions to estimate the saturation values<sup>29</sup>:

- NREL’s Puerto Rico Energy Efficiency Scenario Analysis Tool (PREESAT) indicates that ~50% of all residential households use HVAC equipment for cooling.
- Assumed that 56.5% of all households are regular income and the remaining 43.5% are low income (based on data provided in PREESAT, NREL, September 2021).

<sup>28</sup> [https://www.brattle.com/wp-content/uploads/2017/10/5760\\_dynamic\\_pricing\\_and\\_demand\\_response.pdf](https://www.brattle.com/wp-content/uploads/2017/10/5760_dynamic_pricing_and_demand_response.pdf)

<sup>29</sup> These assumptions can be updated as and when actual baseline data is available.

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- Assumed that 80% of regular income households use some type of HVAC equipment for cooling and 20% of low-income households use some type of HVAC equipment for cooling.
- Assumed ductless mini split AC share of 75% and window AC share of 25% within the overall HVAC equipment saturation for regular income households.
- Assumed ductless mini split AC share of 10% and window AC share of 90% within the overall HVAC equipment saturation for low-income households.

These assumptions regarding saturations and weights lead to a weighted average saturation of 19% for window AC and 35% for ductless mini split ACs overall for all residential customers.

**Table 3-9: Residential HVAC Direct Load Control Overview**

Item	Description
<b>Overview of HVAC DLC Option</b>	<p>This includes the following measures:</p> <ul style="list-style-type: none"> <li>• DLC – Window AC Control, which is specific to window AC units and can be controlled by a thermostat or switch.</li> <li>• DLC – Ductless Mini Split AC, which is for ductless mini splits AC units controlled by a thermostat or switch.</li> </ul>
<b>Eligible Customers</b>	<ul style="list-style-type: none"> <li>• All residential customer classes not enrolled in TOU and CPP.</li> <li>• End-use saturation: 19% for window AC and 35% for ductless mini split ACs overall for all residential customers. (described above).</li> <li>• Control strategy eligibility: assumed that the percentage of households with either mini split or window AC with smart thermostat and/or smart switch progressively increases from 10% of all households with HVAC equipment in CY24 to 100% of all households with HVAC equipment by CY33 (increases linearly by 10% every year for over 10 years to reach full adoption of the smart technology)<sup>30</sup>.</li> </ul>
<b>Participation Assumptions</b>	<ul style="list-style-type: none"> <li>• Steady state participation is 15% of eligible customers (after end-use saturation and control strategy eligibility are factored in) for each of the two end-use equipment.</li> <li>• Residential participation uses a S-shape ramp beginning in CY28 up to steady state participation level of 15% (100% ramped up) by CY33 for DLC - Window AC Control and DLC - Ductless Mini Split/Heat Pump Control.</li> <li>• The opt-out factor for these measures is assumed to be 10% (this represents the average number of enrolled participants that opt-out of load reduction in individual events).</li> </ul>

<sup>30</sup> Assumed a 10-year equipment lifetime, which means that one-tenth of the stock turns over every year and gets replaced with smart controllable equipment.

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Item	Description
<b>Unit Impact</b>	<ul style="list-style-type: none"> <li>DLC – Window AC and Ductless Mini Split AC: 0.084 kW per controlled device<sup>31</sup>; 0.168 kW per participant (assumed average two units per customer with window AC or ductless mini split AC units<sup>32</sup>).</li> </ul>
<b>Levelized Costs</b>	<ul style="list-style-type: none"> <li>DLC – Window AC Control: \$600/kW-yr.<sup>33</sup></li> <li>DLC – Ductless Mini Split/Heat Pump Control: \$240/kW-yr.<sup>34</sup></li> </ul>
<b>Incentive Splits</b>	<ul style="list-style-type: none"> <li>70% incentive share in overall costs; 30% non-incentive share.</li> </ul>

## 3.4.4 Residential Water Heating Direct Load Control

A summary of the Residential Water Heating Direct Load Control option is provided in Table 11. This table states the key assumptions for potential and cost calculations for this measure as described previously in Sections 3.3.4 and 3.3.5. These assumptions are based on best available data sources and would need to be updated based on actual baseline data for Puerto Rico, when available.

<sup>31</sup> Consolidated Edison Report on Program Performance and Cost Effectiveness of Demand Response Programs- 2020, November 16, 2020. Window AC and Ductless Mini Split AC control is not common, and therefore the Con Edison pilot is the best available information source that is public. The impact in Puerto Rico could be different from that realized in New York City and should be updated and verified based on pilots in Puerto Rico. However, in the absence of any pilot or any other Puerto Rico specific information source, the per device load reduction assumption information from the Con Edison pilot is the best available information source.

<sup>32</sup> According to the Energy Information Administration (EIA) – “On average, a home that uses individual air-conditioning units has two window, wall, or portable units”  
<https://www.eia.gov/todayinenergy/detail.php?id=36692#:~:text=On%20average%2C%20a%20home%20that,%2C%20wall%2C%20or%20portable%20units.>

<sup>33</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

<sup>34</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

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**Table 3-10: Residential Water Heating Direct Load Control Overview**

Item	Description
<b>Overview of WH DLC Option</b>	<p>This includes the following measures:</p> <ul style="list-style-type: none"> <li>DLC – Water Heating Control, which is the use of a smart water heater to control water heating load during a DR event.</li> </ul>
<b>Eligible Customers</b>	<ul style="list-style-type: none"> <li>All residential customer classes not enrolled in TOU and CPP measures with eligible end-use equipment and control.</li> <li>End-use saturation: Assumed overall saturation of electric water heating among residential customers: 94%<sup>35</sup></li> <li>Control strategy eligibility begins in CY24 at 10% and increases by 10% every year until 100% is reached in CY33, implying that 10% of households with electric water heating have a smart controllable water heater in CY24 and this percentage linearly increases over 10 years to reach 100% by CY33 (translates to all households with electric water heating have smart controllable water heaters by CY33)<sup>36</sup>.</li> </ul>
<b>Participation Assumptions</b>	<ul style="list-style-type: none"> <li>Steady state participation is 20% of eligible customers (after end-use saturation and control strategy eligibility are factored in).</li> <li>Residential participation uses a S-shape ramp beginning in CY28 up to steady state participation level of 20% by CY33 (100% ramped up by CY33).</li> <li>The opt-out factor is assumed to be 5% (this represents the average number of enrolled participants that opt-out of load reduction in individual events).</li> </ul>
<b>Unit Impacts (Average Peak Demand Reduction)</b>	<ul style="list-style-type: none"> <li>Average coincident water heating peak demand per customer is ~0.1 kW<sup>37</sup></li> <li>Water heater is turned off during DR events, so 100% of the water heating demand is shed during the event.</li> </ul>
<b>Levelized Costs</b>	<ul style="list-style-type: none"> <li>\$240/kW-yr. levelized cost<sup>38</sup></li> </ul>
<b>Incentive Splits</b>	<ul style="list-style-type: none"> <li>70% incentive split, 30% non-incentive split</li> </ul>

<sup>35</sup> Assumed 100% of non-low-income households and 80% of low-income households have electric water heating, which translates to a weighted average saturation of 94% based on a 70:30 split of non-low-income and low-income households of the total residential population.

<sup>36</sup> Assumed a 10-year equipment lifetime, which means that one-tenth of the stock turns over every year and gets replaced with smart controllable equipment.

<sup>37</sup> Water heating demand is assessed to be 7% of the overall residential coincident peak demand. The share of water heating in overall residential demand is based on Florida data in NREL's [ResStock](#) database. The rationale for choosing Florida for deriving the end-use share for Puerto Rico is based on the fact that – 1) no primary data exists for Puerto Rico; 2) Florida's overall residential load shape is similar to Puerto Rico's and is the best available information source to derive end-use shares in demand in the absence of primary data.

<sup>38</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

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## 3.4.5 Behind-the-Meter (BTM) Battery Dispatch

A summary table of the BTM Battery Dispatch option is provided in Table 12. This table states the key assumptions for potential and cost calculations for this measure as described previously in Sections 3.3.4 and 3.3.5. The basis for these assumptions is described below the table.

**Table 3-11: BTM Battery Dispatch Overview**

Item	Description
<b>Overview of BTM Battery Dispatch Option</b>	<p>This includes the following measures:</p> <ul style="list-style-type: none"> <li>Residential BTM Battery Dispatch, which follows LUMA's Battery Emergency Demand Response Program (BEDRP) by providing compensation to enrolled customers for dispatching battery resources during DR events.<sup>39</sup></li> </ul>
<b>Eligible Customers</b>	<ul style="list-style-type: none"> <li>All residential customers with BTM batteries.<sup>40</sup></li> </ul>
<b>Enrollment Assumptions</b>	<ul style="list-style-type: none"> <li>Steady state participation: 50% of customers with BTM batteries.</li> <li>A linear participation begins in CY25, reaching steady state participation level by CY29 (100% ramped up).</li> <li>The opt-out factor is assumed to be 20% (this represents the average number of enrolled participants that opt-out of battery dispatch during DR events)<sup>41</sup>.</li> </ul>
<b>Unit Impact</b>	<ul style="list-style-type: none"> <li>1.07 kW per battery available for dispatch (assumed 3-4 hr. event duration)<sup>42</sup>.</li> </ul>
<b>Levelized Costs</b>	<ul style="list-style-type: none"> <li>\$226/kW-yr. levelized cost<sup>43</sup></li> </ul>
<b>Incentive Splits</b>	<ul style="list-style-type: none"> <li>80% incentive split, 20% non-incentive split</li> </ul>

There is a significant and growing base of BTM batteries in Puerto Rico, most of which are installed at the homes of customers who are also participating in LUMA's Net Energy Metering (NEM) Program. Prior to 2029, only batteries for NEM customers would be dispatched and standalone battery dispatch would

<sup>39</sup> This study only included discharge of batteries to reduce peak demand. We did not model charging of batteries during renewable curtailment periods since it was not within the study scope. However, charging of batteries to mitigate renewable curtailment should be considered as an additional value stream from batteries for Puerto Rico.

<sup>40</sup> The battery adoption is tied to the projections of NEM customers and is described below.

<sup>41</sup> Value from LUMA's battery pilot program.

<sup>42</sup> Value from LUMA's battery pilot program. Assumed 31% of DBESS energy capacity enrolled.

<sup>43</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

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begin from 2029 onward. This study used the battery adoption forecast made for LUMA by Guidehouse, which included solar paired batteries and standalone battery projections. For demand response purposes, the maximum participation for batteries enrolled in a DR program is assumed to be 50%, with a linear ramp beginning in 2025 that reaches the steady state participation value by 2029. The available dispatchable capacity assumes that about 69% of the battery capacity is held in reserve by the customers, so 31% of the battery capacity is available for dispatch by LUMA, based on pilot results provided by LUMA.

These batteries are intended primarily to provide resiliency to customers in the event of a power outage. As such, they generally sit fully charged at all times for maximum resiliency. These batteries also represent a significant demand response resource because they can be discharged during peak demand periods based on a dispatch signal provided by LUMA. While battery energy storage and power capacity vary based on the battery supplier, a typical residential BTM battery has approximately 13 kWh of energy storage and discharge capacity power rating of approximately 5 kW.

As part of its portfolio of EE/DR programs under the EE/DR Transition Period Plan that was approved by the Energy Bureau, LUMA is currently in the midst of launching a Battery Emergency Demand Response Program (BEDRP) for the summer of 2023 to test the DR potential of BTM batteries. The BEDRP will be delivered by third-party Emergency Demand Response (EDR) Aggregators authorized and qualified by LUMA who will enroll customers, dispatch battery resources during events and compensate customers for the energy provided. Customers may only participate in the Program by enrolling with an EDR Aggregator. The EDR Aggregator will manage communication with its enrolled customers' storage devices to ensure customers electing to participate in events set their systems to maintain the required state of charge and that the battery resources dispatch in accordance with instructions provided by LUMA. Participation in any DR event is strictly voluntary on the part of any participating customers, who can choose to opt-out of any event at their discretion.

The budget for this initial phase of the BEDRP is limited to approximately \$5 million annually which, in turn, limits participation to approximately 6,000 customers based on LUMA's current dispatch and incentive projections.

The BEDRP will provide valuable learnings for future expansion of the program to capture more of the BTM capacity. One of the key questions relates to how much capacity will be available from each BTM battery per DR event. Our assumptions are informed by the BEDRP pilot findings that LUMA has provided. These findings suggest that 31% of DBESS energy capacity was enrolled by the customers and 20% of the batteries enrolled opted out in each event. Experience in other jurisdictions offering similar programs to the BEDRP indicates they are attractive to customers.

### 3.5 Commercial Demand Response Assumptions

As previously discussed in Section 3.2, the relevant DR measures for commercial customers are the two time-varying rates or pricing options – Time-Of-Use rate and Critical Peak Pricing rate, and HVAC load control measures of two types – manual curtailment and Auto-DR enabled curtailment. These are briefly described below with assumptions used for potential and cost calculations.

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## 3.5.1 Commercial TOU Rates

A summary of the Commercial TOU Rates is provided in Table 13. This table states the key assumptions for potential and cost calculations for this measure as described previously in Sections 3.3.4 and 3.3.5. Additional description of the TOU rate is presented after the table.

**Table 3-12: Commercial TOU Rates Overview**

Item	Description
<b>Overview of Commercial TOU Option</b>	<ul style="list-style-type: none"> <li>Voluntary opt-in commercial TOU rate, which has predetermined prices for on and off-peak hours that incentivize customers to shift load from peak to off-peak periods.</li> <li>Three-tiered TOU rate with peak to off-peak ratio of 1.6 <i>(please refer to detailed description of the rate following this table).</i></li> </ul>
<b>Eligible Customers</b>	<ul style="list-style-type: none"> <li>All commercial customers.</li> </ul>
<b>Participation assumptions</b>	<ul style="list-style-type: none"> <li>Steady state participation is 15% of all commercial customers.<sup>44</sup></li> <li>A S-shaped ramp for participation begins from CY29 onwards following AMI deployment, reaching 100% ramp (reaches steady-state participation of 15%) for eligible customers by CY35.</li> </ul>
<b>Unit Impact<sup>45</sup></b>	<ul style="list-style-type: none"> <li>3% reduction in coincident peak demand.</li> </ul>
<b>Levelized Costs</b>	<ul style="list-style-type: none"> <li>\$24/kW-yr. levelized cost<sup>46</sup></li> </ul>
<b>Incentive Splits<sup>47</sup></b>	<ul style="list-style-type: none"> <li>0% incentive split since this is a rate-based measure, 100% non-incentive split</li> </ul>

The Commercial TOU rates used for this study were structured similarly to, and based on the same underlying assumptions as, the Interim EV TOU rates that were proposed by LUMA in its September 1,

<sup>44</sup> Represents participation levels in mature programs after an option is fully ramped up.

<sup>45</sup> Impact assumption is based on The Brattle Group research further described in the TOU rate description below. These impact %s are applied to the coincident peak demand. The coincident peak demand is based on commercial hourly load data for Puerto Rico and the peak period definition described in Section 3.3.1 and is estimated using the market characterization approach described in Section 3.3.2

<sup>46</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

<sup>47</sup> This represents the incentive and the non-incentive fractions/shares in the total levelized cost.

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2022 Motion<sup>48</sup> and approved by the Energy Bureau in its January 13, 2023 Resolution and Order<sup>49</sup>. This is consistent with the approach used to derive the Residential TOU rates.

The key structural features of the Commercial TOU rates used for this study are as follows:

- 3-part pricing applicable on all days (including holidays and weekends):
  - Off-Peak period roughly coincident with period of maximum solar PV output,
  - Shoulder period, and
  - On-Peak period roughly coincident with the period of highest system demand.
- 1.6:1 ratio of On-Peak to Off-Peak rates
- TOU rate only applies to the FCA and PPCA component of the bill. The FCA and PPCA in effect in Q2, 2023 were used in determining the rates.

The resultant Commercial TOU rates derived based on the above approach and used in this study are provided in Figure 20. As shown, the all-in commercial TOU rate varies from a low of approximately 21 cents / kWh for the mid-day Off-peak Period to almost 34 cents / kWh for the evening On-Peak period. These rates differ from the Residential TOU rates largely because the commercial load profile is different than the residential load profile. This difference yields a higher Off-Peak and On-Peak price for commercial customers.

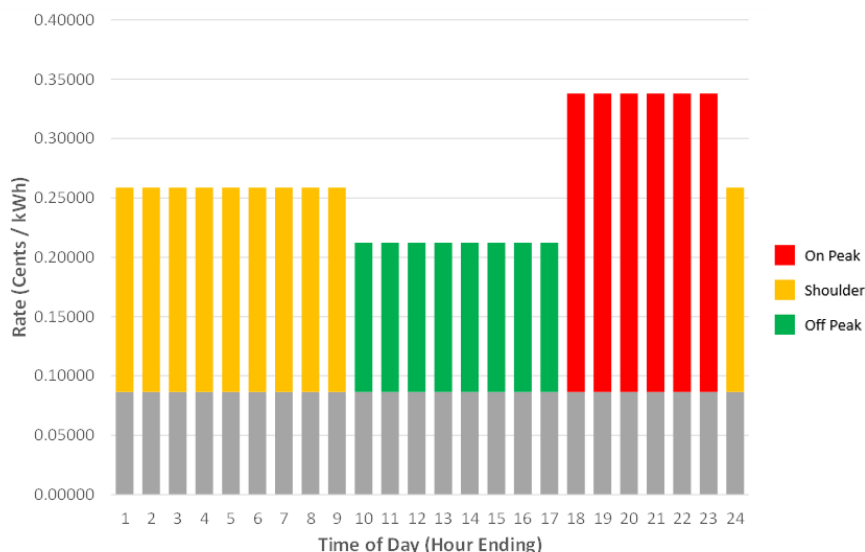
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<sup>48</sup> NEPR-MI-2021-0013, The Deployment of Electric Vehicle Charging Infrastructure, Motion Submitting Draft Phase I EV Plan and Request to Postpone Compliance Technical Hearing No.3 and Concomitant Deadline to Submit Revised Phase I EV Plan September 1, 2022 and Motion Re-Submitting Exhibit 1 Filed on September 1, 2022 with Technical Repairs and Requesting Substitution of Original Exhibit, September 2, 2022.

<sup>49</sup> NEPR-MI-2021-0013, The Deployment of Electric Vehicle Charging Infrastructure, Draft Phase I EV Plan and Revised EV Rate Design, January 13, 2023.

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**Figure 20: Commercial TOU Rates Used in Study**



The individual components of the Commercial TOU rate are as follows:

**Table 3-13: Commercial TOU Rate Components**

Rate Component (\$ / kWh)	Off-Peak	Shoulder	On-Peak
<b>Time-varying FCA &amp; PPCA</b>	0.13	0.17	0.25
<b>Other Rate Components (non-time-varying)</b>	0.09	0.09	0.09
<b>Total "All-in" Rate</b>	<b>0.21</b>	<b>0.26</b>	<b>0.34</b>

For the purposes of estimating the reduction in commercial load and system peak due to the Commercial TOU Rates, Guidehouse used the ratio of the all-in price during the On-peak period to the all-in price during the Off-peak period. Based on the all-in rates shown in Table 14, this key ratio for commercial TOU rates is 1.6. While future costs and rates will differ from that shown above and used in the Guidehouse analysis, if the relative contribution of the FCA and PPCA to the all-in price remains roughly the same, and the On-Peak FCA and PPCA component of the commercial rate continues to be twice that of the Off-Peak component, then this key ratio of 1.6 based on the all-in rates will remain relatively stable for commercial customers and the findings would still be applicable under different cost and rate assumptions. For these reasons, Guidehouse believes that using an On-Peak/Off-Peak all-in rate ratio of 1.6 provides a robust mid-point estimate for use in estimating peak demand reductions due to Commercial TOU rates.

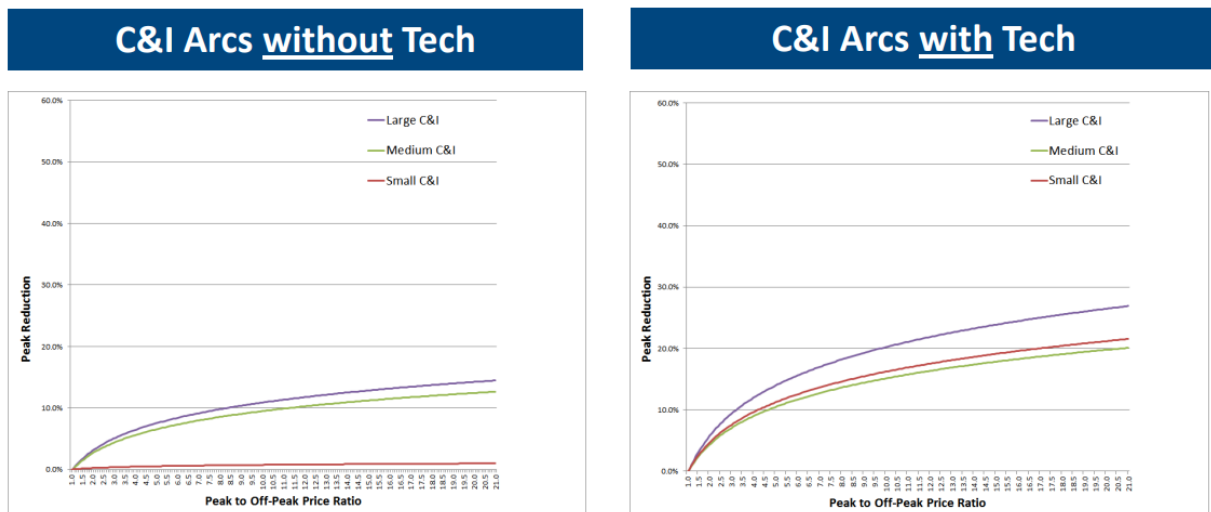
Based on a compilation by the Brattle Group of C&I TOU impacts drawn from a limited number of C&I TOU implementations and pilots<sup>50</sup>, Guidehouse estimates that the peak demand reduction from a 1.6 On-

<sup>50</sup> The Brattle Group, *Demand Response Market Research for Portland General Electric, 2016-2035*, January 2016

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Peak / Off-Peak price ratio will be approximately 3%. This is based on the chart on the left side of Figure 21. Guidehouse chose the midpoint between the two lines representing the different sizes of C&I customers. Note that C&I elasticity is generally lower than residential elasticity, which is reflected in the lower peak demand reduction for C&I customers as compared with residential customers.

Figure 21: C&I Peak Demand Reduction for Varying TOU and Dynamic Price Ratios<sup>51</sup>



## 3.5.2 Commercial Critical Peak Pricing

A summary of the Commercial CPP rate is provided in Table 15. This table states the key assumptions for potential and cost calculations for this measure as described previously in Sections 3.3.4 and 3.3.5. Additional description of the CPP rate is presented after the table.

<sup>51</sup> *Ibid.*

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**Table 3-14: Commercial Critical Peak Pricing Overview**

Item	Description
<p><b>Overview of Commercial CPP Option</b></p>	<p>The CPP rate includes a significantly higher rate during DR event periods (referred to as the Critical Peak Period – CPP) than the customer’s Otherwise Applicable Tariff (OAT) that signals the customer to reduce load during the CPP event period. The rate in non-CPP hours in a CPP tariff is lower than a customer’s OAT, which incentivizes the customer to reduce load during the critical peak periods. Unlike a TOU rate, a CPP rate is event-based and dispatchable. It is typically offered as a voluntary opt-in rate.</p> <p>Customers can respond to the CPP signals either by manually reducing load during the CPP event (referred to as “CPP without enabling technology”) or their response could be automated using enabling technology such as energy management systems (referred to as “CPP with enabling technology”).</p> <p>Critical peak to off-peak ratio: 5.6 for both CPP measures  <i>(please refer to detailed description of the rate following this table).</i></p>
<p><b>Eligible Customers</b></p>	<ul style="list-style-type: none"> <li>• All commercial customers not enrolled in TOU (based on hierarchy).</li> <li>• The control strategy eligibility split between “without” and “with enabling technology” begins at 100% for CPP without enabling tech, but 10% shifts over to CPP with enabling tech every year starting CY24 until CPP with enabling technology reaches 100% in CY33 while CPP without enabling technology reaches 0%.</li> </ul>
<p><b>Participation Assumptions</b></p>	<ul style="list-style-type: none"> <li>• Steady state participation is 20% of eligible customers.</li> <li>• An S-shaped ramp for participation begins in CY29 with the availability of AMI, reaching 100% ramp (with participation level at 20%) for eligible customers by CY34 for both CPP measures.</li> </ul>
<p><b>Unit Impacts<sup>52</sup></b></p>	<ul style="list-style-type: none"> <li>• Commercial CPP without enabling tech: 7% of total facility load for eligible customers.</li> <li>• Commercial CPP with enabling tech: 14% of total facility load for eligible customers.</li> </ul>

<sup>52</sup> Impact assumption is based on The Brattle Group research further described in the CPP rate description below. These impact %s are applied to the coincident peak demand. The coincident peak demand is based on commercial hourly load data for Puerto Rico and the peak period definition described in Section 3.3.1 and is estimated using the market characterization approach described in Section 3.3.2

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Item	Description
<b>Levelized Costs</b> <sup>53</sup>	<ul style="list-style-type: none"> <li>Commercial CPP without enabling tech: \$60/kW-yr.<sup>54</sup></li> <li>Commercial CPP with enabling tech: \$120/kW-yr.<sup>55</sup></li> </ul>
<b>Incentive Splits</b>	<ul style="list-style-type: none"> <li>Commercial CPP without enabling tech: 0% incentive split since this is a rate-based measure and therefore there are no separate incentives to customers for enrolling and responding to CPP events, 100% non-incentive split.</li> <li>Commercial CPP with enabling tech: 70% incentive split which represents the one-time enabling technology costs offered to customers at the time of enrollment to provide enhanced response to CPP events, 30% non-incentive split.</li> </ul>

The Commercial CPP rates used for this study were derived using the same approach as described above in Section 3.4.2 on page 33.

- CPP rate only applies to the FCA and PPCA component of the bill. The FCA and PPCA in effect in Q2, 2023 were used in determining the CPP rates.
- CPP rates are revenue neutral for FCA and PPCA based on the commercial load profile (i.e., the average commercial customer will pay the same under base rate and CPP rate absent any key differences between the Residential CPP and TOU rates)
- The CPP rate only applies during the top 40 demand hours of the year that fall under the peak period as defined in Section 3.3.1 (with the remaining hours of the year being the “Base” rate).
- A 5.6:1 ratio between the CPP and Base rate based on experience elsewhere.

As discussed in Section 3.4.2 Residential Critical Peak Pricing, analysis of the CY34 forecast data shows that there are expected to be 17 days with CPP hours (top 40 hours) in them. CPP events are expected to range from 1 – 4 hours duration as shown. The Guidehouse analysis focused only on the top 40 hours, but some CPP programs have fixed duration CPP events (rather than the variable duration assumed by Guidehouse in the analysis). As shown in Table 8, using a four-hour fixed duration CPP event for any hour that falls into the top 40 system demand hours would increase the number of CPP hours to 68. Guidehouse believes both designs – variable or fixed CPP duration – would be attractive to some customers and both are reasonable and viable design alternatives. Customers would be provided day-ahead notification of CPP. Given the commercial load profile and requirement for revenue neutrality for

<sup>53</sup> The levelized cost values in these overview tables do not factor in the Puerto Rico Cost Adder (additional 20%). The adder was used later in analysis, while this table’s values show our initial assumptions.

<sup>54</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

<sup>55</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

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collection of FCA and PPCA under the CPP, the resultant commercial CPP rate components are shown in Table 16.

**Table 3-15: Commercial CPP Rate Components**

Rate Component (\$ / kWh)	Critical Peak Period	Base Rate (all other hours)
<b>Time-varying FCA &amp; PPCA</b>	1.29	0.16
<b>Other Rate Components (non-time-varying)</b>	0.09	0.09
<b>Total "All-in" Rate</b>	<b>1.38</b>	<b>0.25</b>

The Base Rate for the Time-varying FCA and PPCA of 16.1283 cents / kWh is 6% lower than the standard rate of 17.22 cents / kWh that would apply to all hours if the customers does not enroll in the CPP rates.

Similarly, as for Residential TOU rates, Guidehouse used the ratio of the all-in price during the CPP period to the all-in price during the Base rate period to determine the % demand reduction during CPP events. Based on the all-in rates shown in , this key ratio for Commercial CPP rates is 5.6 While future costs and rates will differ from that shown above and used in the Guidehouse analysis, if the relative contribution of the FCA and PPCA to the all-in price remains roughly the same, and the FCA and PPCA component of the commercial rate during Critical Peak Periods continues to be eight (8) times that of the FCA and PPCA component during the Base period, then this key ratio of 5.6 will remain relatively stable and the findings would still be applicable under different cost and rate assumptions. Guidehouse believes that using an CPP all-in rate ratio of 5.6 provides a robust mid-point estimate for use in estimating peak demand reductions due to Commercial CPP rates.

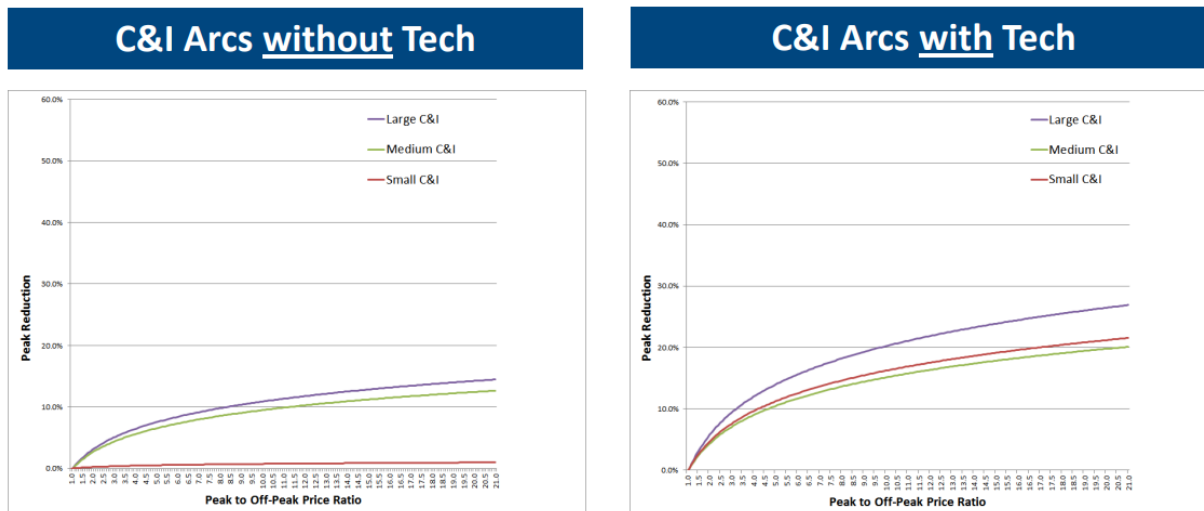
As described in the Residential Critical Peak Pricing section, experience with CPP rates demonstrates there is a significant difference in response between commercial customers that are “technology-enabled” and those who are not. “Technology-enabled” simply refers to any technology that automates the customer response to the CPP price signal.

Based on a compilation by the Brattle Group of C&I TOU impacts drawn from a limited number of C&I TOU implementations and pilots<sup>56</sup>, Guidehouse estimates that the peak demand reduction from a 5.6 CPP / Base rate price ratio will be approximately 7% for commercial customers that are not “technology-enabled” and 14% for commercial customers that are “technology-enabled”. This is based on the chart on the right side of Figure 22. Guidehouse chose the midpoint between the three lines representing the different sizes of C&I customers.

<sup>56</sup> The Brattle Group, *Demand Response Market Research for Portland General Electric, 2016-2035*, January 2016

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Figure 22: C&I Peak Demand Reduction for Varying TOU and Dynamic Price Ratios<sup>57</sup>



### 3.5.3 Commercial HVAC Curtailment

A summary table of the Commercial HVAC Curtailment option is provided in Table 17. This table states the key assumptions for potential and cost calculations for this measure as described previously in Sections 3.3.4 and 3.3.5. These assumptions are based on best available data sources and would need to be updated based on actual baseline data for Puerto Rico, when available.

Table 3-16: Commercial HVAC Curtailment Overview

Item	Description
<b>Overview of Commercial HVAC Curtailment Option</b>	This includes the following measures: <ul style="list-style-type: none"> <li>• Curtailment – HVAC Control – Manual: participant manually curtails the HVAC load during a DR event.</li> <li>• Curtailment – HVAC Control – Auto-DR: participant load curtailment is automated, which implies that curtailment strategies are pre-programmed into the facility energy management system (EMS) and are executed automatically when a DR event signal is received, without any manual intervention.</li> </ul>
	<ul style="list-style-type: none"> <li>• All commercial customers not enrolled in TOU and CPP.</li> </ul>
<b>Eligible Customers</b>	<ul style="list-style-type: none"> <li>• Assumed Auto-DR enabled curtailment (tied to EMS) increases linearly from 10% in CY24 to 100% in CY33.</li> </ul>

<sup>57</sup> Ibid.

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Item	Description
<b>Enrollment Assumptions</b>	<ul style="list-style-type: none"> <li>Steady state participation is 30% of eligible customers.</li> <li>A S-shaped participation ramp assumed for both measures, beginning CY28, with full ramp up to steady state participation level by CY33.</li> <li>The opt-out factor for these measures is assumed to be 10% (this represents the average number of enrolled participants that opt-out of load reduction in individual events).</li> </ul>
<b>Unit Impacts (Average Peak Demand Reduction)</b>	<ul style="list-style-type: none"> <li>Curtailment – HVAC Control Manual: 33% of HVAC load<sup>58</sup></li> <li>Curtailment – HVAC Control DR: 66% of HVAC load<sup>59</sup></li> </ul>
<b>Levelized Costs</b>	<ul style="list-style-type: none"> <li>\$84/kW-yr. levelized cost for both measures<sup>60</sup></li> </ul>
<b>Incentive Splits</b>	<ul style="list-style-type: none"> <li>70% incentive split, 30% non-incentive split for both measures</li> </ul>

## 3.6 Industrial Demand Response Assumptions

As previously discussed in Section 3.2, the relevant DR measures for industrial customers are the two time-varying rates or pricing options – Time-Of-Use rate and Critical Peak Pricing rate, and industrial load curtailment. These are briefly described below with assumptions used for potential and cost calculations.

### 3.6.1 Industrial TOU Rates

A summary table of the Industrial TOU Rates option is provided in Table 18. This table states the key assumptions for potential and cost calculations for this measure as described previously in Sections 3.3.4 and 3.3.5. Additional description of the TOU rate is presented after the table.

<sup>58</sup> HVAC is assessed to have 57% share in the aggregate commercial sector coincident peak demand. The commercial sector coincident peak demand is based on commercial sector hourly load data for Puerto Rico. The share of HVAC in overall commercial demand is based on Florida data in NREL's [ComStock](#) database. The rationale for choosing Florida for deriving the end-use share in peak demand for Puerto Rico is based on the fact that – 1) no primary data exists for Puerto Rico; 2) Florida's overall commercial load shape is similar to Puerto Rico's and is the best available information source to derive end-use shares in demand in the absence of primary data.

<sup>59</sup> *Ibid.*

<sup>60</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

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**Table 3-17: Industrial TOU Rates Overview**

Item	Description
<b>Overview of Industrial TOU Option</b>	<ul style="list-style-type: none"> <li>Voluntary opt-in industrial TOU rate, which has predetermined prices for on and off-peak hours that incentivize residential customers to shift load from peak to off-peak periods.</li> <li>Three-tiered TOU rate with peak to off-peak ratio of 1.7 <i>(please refer to detailed description of the rate following this table).</i></li> </ul>
<b>Eligible Customers</b>	<ul style="list-style-type: none"> <li>All industrial customers.</li> </ul>
<b>Participation Assumptions</b>	<ul style="list-style-type: none"> <li>Steady state participation is 15% of all industrial customers.<sup>61</sup></li> <li>A S-shaped ramp for participation begins from CY29 onwards following AMI deployment, ramping up to 100% of steady-state participation of 15% of eligible customers by CY35.</li> </ul>
<b>Unit Impact<sup>62</sup></b>	<ul style="list-style-type: none"> <li>3% of the total facility load.</li> </ul>
<b>Levelized Costs</b>	<ul style="list-style-type: none"> <li>\$24/kW-yr. levelized cost<sup>63</sup></li> </ul>
<b>Incentive Splits<sup>64</sup></b>	<ul style="list-style-type: none"> <li>0% incentive split, 100% non-incentive split</li> </ul>

The Industrial TOU rates used for this study were structured similarly to, and based on the same underlying assumptions as, the Interim EV TOU rates that were proposed by LUMA in its September 1, 2022 Motion<sup>65</sup> and approved by the Energy Bureau in its January 13, 2023 Resolution and Order<sup>66</sup>. This is consistent with the approach used to derive the Residential TOU rates as described in section 3.4.1 Residential TOU Rates on page 29.

The key structural features of the Industrial TOU rates used for this study are as follows:

<sup>61</sup> Represents participation levels in mature programs after an option is fully ramped up.

<sup>62</sup> Impact assumption is based on The Brattle Group research further described in the TOU rate description below. These impact %s are applied to the coincident peak demand. The coincident peak demand is based on industrial hourly load data for Puerto Rico and the peak period definition described in Section 3.3.1 and is estimated using the market characterization approach described in Section 3.3.2

<sup>63</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

<sup>64</sup> This represents the incentive and the non-incentive fractions/shares in the total levelized cost.

<sup>65</sup> NEPR-MI-2021-0013, The Deployment of Electric Vehicle Charging Infrastructure, Motion Submitting Draft Phase I EV Plan and Request to Postpone Compliance Technical Hearing No.3 and Concomitant Deadline to Submit Revised Phase I EV Plan September 1, 2022 and Motion Re-Submitting Exhibit 1 Filed on September 1, 2022 with Technical Repairs and Requesting Substitution of Original Exhibit, September 2, 2022.

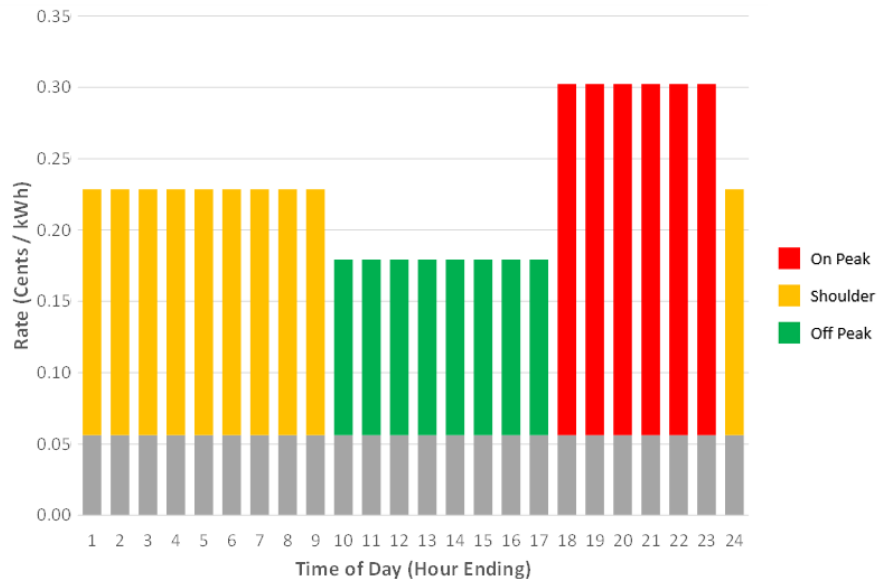
<sup>66</sup> NEPR-MI-2021-0013, The Deployment of Electric Vehicle Charging Infrastructure, Draft Phase I EV Plan and Revised EV Rate Design, January 13, 2023.

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- 3-part pricing applicable on all days (including holidays and weekends):
  - Off-Peak period roughly coincident with period of maximum solar PV output,
  - Shoulder period, and
  - On-Peak period roughly coincident with the period of highest system demand.
- 1.7:1 ratio of On-Peak to Off-Peak rates
- TOU rate only applies to the FCA and PPCA component of the bill. The FCA and PPCA in effect in Q2, 2023 were used in determining the rates.

The resultant Industrial TOU rates derived based on the above approach and used in this study are provided in Figure 23. As shown, the all-in Industrial TOU rate varies from a low of approximately 18 cents / kWh for the mid-day Off-peak Period to approximately 30 cents / kWh for the evening On-Peak period. These rates are similar to the Residential TOU rate, most likely driven by similar relative consumption in each of the three TOU periods by residential and industrial customers.

**Figure 23: Industrial TOU Rates Used in Study**



The individual components of the industrial TOU rate are as follows:

**Table 3-18: Industrial TOU Rate Components**

Rate Component (\$ / kWh)	Off-Peak	Shoulder	On-Peak
<b>Time-varying FCA &amp; PPCA</b>	0.123037	0.172249	0.246075
<b>Other Rate Components (non-time-varying)</b>	0.056267	0.056267	0.056267
<b>Total "All-in" Rate</b>	<b>0.179304</b>	<b>0.228516</b>	<b>0.302342</b>

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For the purposes of estimating the reduction in industrial load and system peak due to the Industrial TOU Rates, Guidehouse used the ratio of the all-in price during the On-peak period to the all-in price during the Off-Peak period. Based on the all-in rates shown in Table 19, this key ratio for Industrial TOU rates is 1.7. While future costs and rates will differ from that shown above and used in the Guidehouse analysis, if the relative contribution of the FCA and PPCA to the all-in price remains roughly the same, and the On-Peak FCA and PPCA component of the industrial rate continues to be twice that of the Off-Peak component,, then this key ratio of 1.7 based on the all-in rates will remain relatively stable for Industrial customers and the findings would still be applicable under different cost and rate assumptions. For these reasons, Guidehouse believes that using an On-Peak/Off-Peak all-in rate ratio of 1.7 provides a robust mid-point estimate for use in estimating peak demand reductions due to Industrial TOU rates.

Based on the all-in price ratio of 1.7 given above, Guidehouse assumed a peak demand reduction of 3% for industrial customers participating in the Industrial TOU rate, the same as for commercial customers. While the Industrial TOU rate yields a slightly higher On-Peak to Off-Peak ratio of 1.7 (vs. 1.6 for commercial) which would suggest that industrial customers participating in the Industrial TOU rate would have a slightly higher peak demand reduction, there was insufficient resolution in the chart from which the estimates were derived to assign a different peak demand reduction to industrial.

### 3.6.2 Industrial Load Curtailment

A summary table of the Industrial Load Curtailment option is provided in Table 20. This table states the key assumptions for potential and cost calculations for this measure as described previously in Sections 3.3.4 and 3.3.5. These assumptions are based on best available data sources and would need to be updated based on actual baseline data for Puerto Rico, when available.

**Table 3-19: Industrial Load Curtailment Overview**

Item	Description
<b>Overview of Industrial Load Curtailment Option</b>	This option represents industrial facility load curtailment during a DR event. The curtailment strategy and the curtailed end-uses depend on the business type.
<b>Eligible Customers</b>	<ul style="list-style-type: none"> <li>All industrial customers not enrolled in TOU.</li> </ul>
<b>Enrollment Assumptions</b>	<ul style="list-style-type: none"> <li>Steady state participation is 25% of eligible customers in the industrial segment.</li> <li>A S-shaped ramp for participation begins in CY28, reaching 100% of the steady state participation level (25%) by CY33.</li> </ul>
<b>Unit Impact</b>	<ul style="list-style-type: none"> <li>10% of total facility load<sup>67</sup>.</li> </ul>

<sup>67</sup> These impact %s are applied to the coincident peak demand. The coincident peak demand is based on commercial hourly load data for Puerto Rico and the peak period definition described in Section 3.3.1 and is estimated using the market characterization approach described in Section 3.3.2

## DR Potential Study

Item	Description
<b>Levelized Costs</b>	<ul style="list-style-type: none"> <li>\$84/kW-yr. levelized cost<sup>68</sup></li> </ul>
<b>Incentive Splits</b>	<ul style="list-style-type: none"> <li>70% incentive split, 30% non-incentive split</li> </ul>

### 3.6.3 Industrial Critical Peak Pricing

A summary table of the Industrial Critical Peak Pricing option is provided in Table 21. This table states the key assumptions for potential and cost calculations for this measure as described previously in Sections 3.3.4 and 3.3.5. Additional description of the CPP rate is presented after the table.

**Table 3-20: Industrial Critical Peak Pricing Overview**

Item	Description
<b>Overview of Industrial CPP Option</b>	<p>The CPP rate includes a significantly higher rate during DR event periods (referred to as the Critical Peak Period – CPP) than the customer’s Otherwise Applicable Tariff (OAT) that signals the customer to reduce load during the CPP event period. The rate in non-CPP hours in a CPP tariff is lower than a customer’s OAT, which incentivizes the customer to reduce load during the critical peak periods. Unlike a TOU rate, a CPP rate is event-based and dispatchable. It is typically offered as a voluntary opt-in rate.</p> <p>Critical peak to off-peak ratio: 6.2</p> <p><i>(please refer to detailed description of the rate following this table).</i></p>
<b>Eligible Customers</b>	<ul style="list-style-type: none"> <li>All industrial customers not enrolled in TOU or Load Curtailment.</li> </ul>
<b>Enrollment Assumptions</b>	<ul style="list-style-type: none"> <li>Steady state participation is 20% of eligible customers in the industrial segment.</li> <li>A S-shaped ramp for participation begins in CY29 with the availability of AMI, ramping up to 100% of steady state participation level by CY34.</li> </ul>
<b>Unit Impact</b>	<ul style="list-style-type: none"> <li>10% of total facility load for eligible customers</li> </ul>

<sup>68</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

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Item	Description
<b>Levelized Costs</b>	<ul style="list-style-type: none"> <li>Industrial CPP rate: \$120/kW-yr.<sup>69</sup></li> </ul>
<b>Incentive Splits</b>	<ul style="list-style-type: none"> <li>Industrial CPP rate: 0% incentive split, 100% non-incentive split</li> </ul>

The Industrial CPP rates used for this study were derived using the same approach as described above in section 3.4.2 on page 33 for the Residential CPP rates:

- CPP rate only applies to the FCA and PPCA component of the bill. The FCA and PPCA in effect in Q2, 2023 were used in determining the CPP rates.
- CPP rates are revenue neutral for FCA and PPCA based on the industrial load profile (i.e., the average commercial customer will pay the same under base rate and CPP rate absent any key differences between the Residential CPP and TOU rates)
- The CPP rate only applies during the top 40 demand hours of the year that fall under the peak period as defined in Section 3.3.1 (with the remaining 8720 hours of the year being the “Base” rate).
- A 6.2:1 ratio between the CPP and Base rate based on experience elsewhere.

As discussed in Section 3.4.2 Residential Critical Peak Pricing, analysis of the CY34 forecast data shows that there are expected to be 17 days with CPP hours (top 40 hours) in them. CPP events are expected to range from 1 – 4 hours duration as shown. The Guidehouse analysis focused only on the top 40 hours, but some CPP programs have fixed duration CPP events (rather than the variable duration assumed by Guidehouse in the analysis). As shown in Table 8, using a four-hour fixed duration CPP event for any hour that falls into the top 40 system demand hours would increase the number of CPP hours to 68. Guidehouse believes both designs – variable or fixed CPP duration – would be attractive to some customers and both are reasonable and viable design alternatives. Customers would be provided day-ahead notification of CPP. Given the industrial load profile and requirement for revenue neutrality for collection of FCA and PPCA under the CPP, the resultant Industrial CPP rate components are shown in Table 22.

**Table 3-21: Industrial CPP Rate Components**

Rate Component (\$ / kWh)	Critical Peak Period	Base Rate (all other hours)
<b>Time-varying FCA &amp; PPCA</b>	1.28	0.16
<b>Other Rate Components (non-time-varying)</b>	0.06	0.06
<b>Total "All-in" Rate</b>	<b>1.34</b>	<b>0.22</b>

<sup>69</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

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The Base Rate for the Time-varying FCA and PPCA of 16.0619 cents / kWh is 7% lower than the standard rate of 17.2249 cents / kWh that would apply to all hours if the customers does not enroll in the CPP rates.

Similarly, as for residential TOU rates, Guidehouse used the ratio of the all-in price during the CPP period to the all-in price during the Base rate period to determine the % demand reduction during CPP events. Based on the all-in rates shown in Table 22, this key ratio for Industrial CPP rates is 6.2. While future costs and rates will differ from that shown above and used in the Guidehouse analysis, if the relative contribution of the FCA and PPCA to the all-in price remains roughly the same, and the FCA and PPCA component of the industrial rate during Critical Peak Periods continues to be eight (8) times that of the FCA and PPCA component during the Base period, then this key ratio of 6.2 will remain relatively stable and the findings would still be applicable under different cost and rate assumptions. Guidehouse believes that using an CPP all-in rate ratio of 6.2 based on the assumptions stated provides a robust mid-point estimate for use in estimating peak demand reductions due to Industrial CPP rates.

Guidehouse expects most industrial customers will be “technology-enabled” due to their need for a more customized response, so a single CPP measure was used for the industrial sector.

## 3.7 Electric Vehicle Demand Response Assumptions

As previously discussed in Section 3.2, the relevant DR measures for electric vehicles are – Time-Of-Use rate, Managed Charging, and V2X. These are briefly described below with assumptions used for potential and cost calculations.

### 3.7.1 EV TOU Rates

A summary of the EV TOU Rates is provided in Table 23. This table states the key assumptions for potential and cost calculations for this measure as described previously in Sections 3.3.4 and 3.3.5. Additional description of the TOU rate is presented after the table.

**Table 3-22: EV TOU Rates Overview**

Item	Description
<b>Overview of EV TOU Option</b>	Three-tiered voluntary opt-in TOU rate for customers with EVs, with predetermined prices for on and off-peak hours that incentivize residential customers to shift EV charging from peak to off-peak periods.  <i>(please refer to detailed description of the rate following this table).</i>
<b>Eligible Vehicles</b>	<ul style="list-style-type: none"> <li>All Light Duty Vehicles (LDVs) and Medium and Heavy-Duty Vehicles (MHDVs).</li> </ul>

# DR Potential Study

Item	Description
<b>Enrollment Assumptions</b>	<ul style="list-style-type: none"> <li>• Steady state participation levels:               <ul style="list-style-type: none"> <li>○ For LDVs: 25%</li> <li>○ For MHDVs: 15%</li> </ul> </li> <li>• Participation Ramp for both vehicle classes: A S-shaped ramp for participation begins from CY25 onwards, ramping up to 100% of steady state participation level by CY30.</li> </ul>
<b>Unit Impacts</b>	<ul style="list-style-type: none"> <li>• For LDVs: 15% of EV charging demand<sup>70</sup></li> <li>• For MHDVs: 11% of EV charging demand<sup>71</sup></li> </ul>
<b>Levelized Costs</b>	<ul style="list-style-type: none"> <li>• \$12/kW-yr. levelized cost<sup>72</sup></li> <li>• Peak to off-peak ratio: 1.7 for LDVs, 1.6 for MHDVs</li> </ul>
<b>Incentive Splits</b>	<ul style="list-style-type: none"> <li>• 0% incentive split, 100% non-incentive split</li> </ul>

The EV TOU rates are consistent with the Interim EV TOU rates that were proposed by LUMA in its September 1, 2022 Motion<sup>73</sup> and approved by the Energy Bureau in its January 13, 2023 Resolution and Order<sup>74</sup>. The only change is that the rates have been updated to reflect the FCA and PPCA in effect in June 2023.

<sup>70</sup> These impact %s are applied to the coincident peak demand. The coincident peak demand is based on LDV hourly load data for Puerto Rico and the peak period definition described in Section 3.3.1 and is estimated using the market characterization approach described in Section 3.3.2

<sup>71</sup> These impact %s are applied to the coincident peak demand. The coincident peak demand is based on MHDV hourly load data for Puerto Rico and the peak period definition described in Section 3.3.1 and is estimated using the market characterization approach described in Section 3.3.2

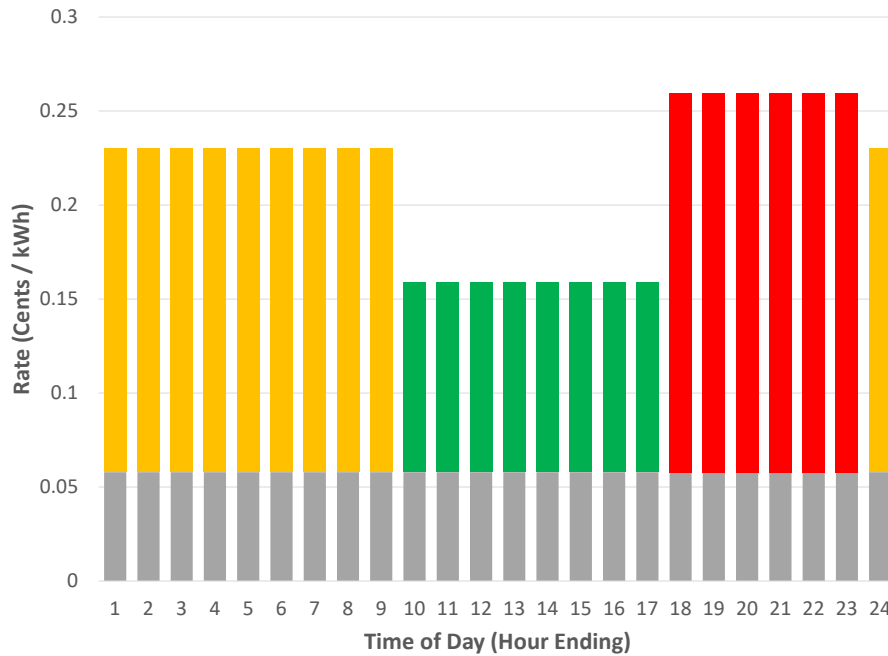
<sup>72</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

<sup>73</sup> NEPR-MI-2021-0013, The Deployment of Electric Vehicle Charging Infrastructure, Motion Submitting Draft Phase I EV Plan and Request to Postpone Compliance Technical Hearing No.3 and Concomitant Deadline to Submit Revised Phase I EV Plan September 1, 2022 and Motion Re-Submitting Exhibit 1 Filed on September 1, 2022 with Technical Repairs and Requesting Substitution of Original Exhibit, September 2, 2022.

<sup>74</sup> NEPR-MI-2021-0013, The Deployment of Electric Vehicle Charging Infrastructure, Draft Phase I EV Plan and Revised EV Rate Design, January 13, 2023.

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Figure 24: Residential EV TOU Rates Used in Study



The individual components of the EV TOU rate are as follows:

Table 3-23: Residential EV TOU Rate Components

Rate Component (\$ / kWh)	Off-Peak	Shoulder	On-Peak
Time-varying FCA & PPCA	0.10	0.17	0.20
Other Rate Components (non-time-varying)	0.06	0.06	0.06
<b>Total "All-in" Rate</b>	<b>0.16</b>	<b>0.23</b>	<b>0.26</b>

## 3.7.2 EV Managed Charging

A summary table of the EV Managed Charging option is provided in Table 25. This table states the key assumptions for potential and cost calculations for this measure as described previously in Sections 3.3.4 and 3.3.5.

Table 3-24: EV Managed Charging Overview

Item	Description
<b>Overview of EV Managed Charging Option</b>	Direct control of EV charging (interrupted charging) either through the EVSE or using onboard vehicle telematics during DR events. This is also referred to as V1G.

## DR Potential Study

Item	Description
<b>Eligible Vehicles</b>	<ul style="list-style-type: none"> <li>All LDVs and MHDVs not enrolled in the EV TOU rate.</li> </ul>
<b>Enrollment Assumptions</b>	<ul style="list-style-type: none"> <li>Steady state participation levels for both LDVs and MHDVs: 30%               <ul style="list-style-type: none"> <li>Participation Ramp for both vehicle classes: A S-shaped ramp for participation begins from CY28 onwards, ramping up to 100% of steady state participation level by CY33.</li> </ul> </li> </ul>
<b>Unit Impact</b>	<ul style="list-style-type: none"> <li>90% of EV charging demand.<sup>75</sup></li> </ul>
<b>Levelized Costs</b>	<ul style="list-style-type: none"> <li>EV Managed Charging for LDVs: \$180/kW-yr. levelized cost<sup>76</sup></li> <li>EV Managed Charging for MHDVs: \$144/kW-yr. levelized cost<sup>77</sup></li> </ul>
<b>Incentive Splits</b>	<ul style="list-style-type: none"> <li>70% incentive split, 30% non-incentive split</li> </ul>

### 3.7.3 EV V2X

A summary table of the EV V2X option is provided in Table 26. This table includes multiplier values and costs for this option. This table states the key assumptions for potential and cost calculations for this measure as described previously in Sections 3.3.4 and 3.3.5. The basis for the assumptions is described in greater detail below the table.

**Table 3-25: EV V2X Overview**

Item	Description
<b>Overview of EV V2X Option</b>	EV V2X refers to export of power from EVs to either serve the energy needs of a building/home (V2B/V2H) or export power directly to the grid (V2G). For power export, EVs need to be equipped with bi-directional charging capability.

<sup>75</sup> These impact %s are applied to the coincident peak demand. The coincident peak demand is based on LDV and MHDV hourly charging load data for Puerto Rico and the peak period definition described in Section 3.3.1 and is estimated using the market characterization approach described in Section 3.3.2.

Unit impact %s are based on EV Managed Charging assumptions in the California statewide Demand Response Potential Study (Lawrence Berkeley National Laboratory, *The California Demand Response Potential Study, Phase 3: Final Report on the Shift Resource through 2030, 2020*, [https://eta-publications.lbl.gov/sites/default/files/ca\\_dr\\_potential\\_study\\_phase\\_3\\_shift\\_final\\_report.pdf](https://eta-publications.lbl.gov/sites/default/files/ca_dr_potential_study_phase_3_shift_final_report.pdf)[https://eta-publications.lbl.gov/sites/default/files/ca\\_dr\\_potential\\_study\\_phase\\_3\\_shift\\_final\\_report.pdf](https://eta-publications.lbl.gov/sites/default/files/ca_dr_potential_study_phase_3_shift_final_report.pdf))

<sup>76</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

<sup>77</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

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Item	Description
<b>Eligible Vehicles</b>	<ul style="list-style-type: none"> <li>All vehicles not enrolled in EV TOU or EV Managed Charging.</li> <li>The technical suitability<sup>78</sup> multiplier for this measure is assumed to increase linearly by about 3% annually starting in CY23 and stabilizes at ~65% in the long-run (in 20 years by CY42).<sup>79</sup></li> </ul> <p><i>Basis for these assumptions described below.</i></p>
<b>Participation Assumptions</b>	<ul style="list-style-type: none"> <li>Steady state participation level: 25% of all eligible vehicles.</li> <li>Participation of eligible vehicles assumed to increase linearly from 2.5% of eligible vehicles in CY30 to a steady-state participation level of 25% of eligible vehicles in CY39 (assumed linear ramp up to steady-state participation level in 10 years, beginning CY30).</li> </ul>
<b>Unit Impacts</b>	<ul style="list-style-type: none"> <li>For LDVs: 11.2 kW capacity/vehicle<sup>80</sup></li> <li>For MHDVs: 41.5 kW capacity/vehicle<sup>81</sup></li> <li>Assumed that on an average 23% of capacity is available for export.<sup>82</sup></li> </ul> <p><i>Basis for these assumptions described below.</i></p>
<b>Levelized Costs</b>	<ul style="list-style-type: none"> <li>For LDVs: \$420/kW-yr. levelized cost<sup>83</sup></li> <li>For MHDVs: \$210/kW-yr. levelized cost<sup>84</sup></li> </ul>
<b>Incentive Splits</b>	<ul style="list-style-type: none"> <li>70% incentive split, 30% non-incentive split</li> </ul>

EV V2X refers to EV bi-directional chargers that allow vehicles to transfer power from their batteries, or those built into the charger, to serve the needs of different energy consuming destinations, such as buildings (V2B), electric grid (V2G) or homes (V2H). Since this mechanism isn't necessarily related to the charging profile, but rather on the available charge across all EVs during the time of DR events, the calculation for DR impacts for this mechanism is different than others. The potential DR impact for this mechanism is calculated based on the percent of available capacity for discharge in EVs at any given

<sup>78</sup> Technical suitability refers to the various requirements (e.g., infrastructure, design, etc.) needed for this measure to be supported.

<sup>79</sup> This assumption is based on insights from industry experts which suggest that around 10% of vehicles would be V2X capable by 2025 and 90% by 2050. This is used to estimate the technical suitability factor in the analysis.

<sup>80</sup> Guidehouse market research

<sup>81</sup> Resolution E-5192. PG&E Advice Letter 6259-E pursuant to Decision 20-12-029. <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M456/K322/456322989.PDF5>

<sup>82</sup> This factor accounts for average effective per vehicle available capacity for export that takes into consideration average charging profiles, connectivity, availability, etc. and is based on information available in "Timothy E. Lipman, *Vehicle-Grid Integration Value Study Literature Review Summary*, Gridworks, 2019, <https://gridworks.org/wp-content/uploads/2019/03/VGI-Value-Literature-Review-Final.pdf><https://gridworks.org/wp-content/uploads/2019/03/VGI-Value-Literature-Review-Final.pdf>".

<sup>83</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

<sup>84</sup> The levelized cost values in these overview tables include the Puerto Rico Cost Adder (additional 20%).

## DR Potential Study

time, as there is no hourly breakdown of this information. This mechanism is also limited by the number of vehicles or chargers that are capable of exporting energy (technical suitability) and the battery export capacity (kW). Additionally, on an average, only a certain fraction of the capacity that is technically suitable is available for export and represents the effective fraction of the total available capacity after factoring in charging profiles, connectivity, availability, etc.

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## 4. Results

This section presents demand reduction and cost estimates from the DR options considered in the assessment described in Section 3. Guidehouse estimated “realistic achievable” demand reduction assumptions based on the assumptions described in Section 3 and developed levelized cost estimates for each DR option.

This section begins with the annual achievable demand reduction estimates from all DR options included in the analysis, and separately calls out demand reduction estimates from the most cost-effective DR options only. The demand reduction results are shown by sector, which help determine the relative contribution of each sector to the total potential. Additionally, it presents annual costs by DR option. This section closes with a discussion of the supply curve results from the analysis, which shows the CY 2044 cumulative demand reduction potential vs. the levelized costs for all DR options.

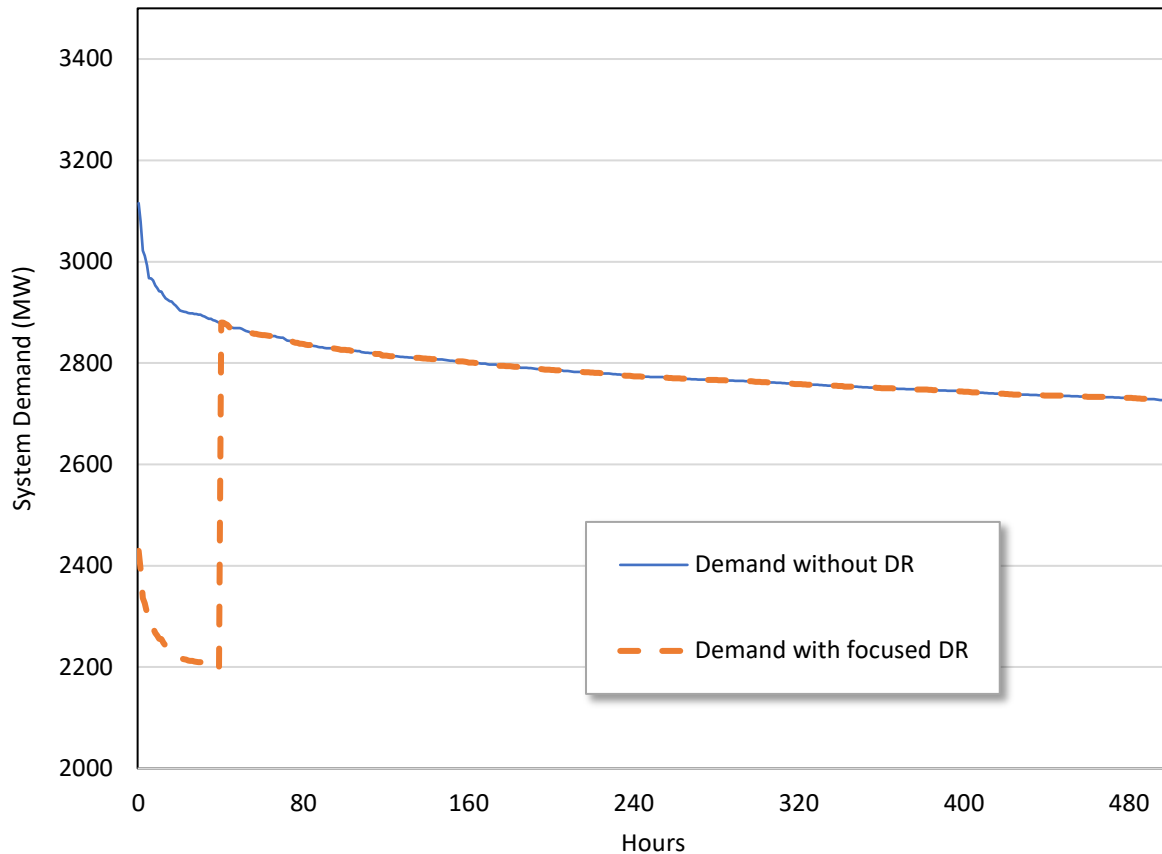
### 4.1 Overall DR Potential Results

The study results show that the potential demand reduction in CY 2044 is 686 MW at an annual cost of \$186 million. As discussed previously in chapters 1 and 2, the estimated potential can be characterized as the “achievable technical” potential since the analysis did not assess cost-effectiveness of DR measures and used “achievable” participation/enrollment assumptions in DR measures.

Note that forecast CY44 DR savings of 686 MW would not actually reduce the system peak demand by the same amount because the 41<sup>st</sup> highest peak demand hour absent any DR would become the highest demand hour after the impact of DR for the top 40 hours. This is illustrated in Figure 25 below which shows the top 500 hours of demand with and without DR. As can be seen, if the DR measures were fully deployed in the top 40 hours, the peak demand in all of these hours would be less than the peak demand in the 41<sup>st</sup> highest hour. In fact, with DR, the peak demand in what would have been the top 40 demand hours absent DR will be less than the peak demand for more than half of the hours in the year.

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Figure 25: Top 500 hours of system demand in 2044 with and without focused DR



Based on this example, it is clear that if the 686 MW of DR capacity were solely deployed during the top 40 hours that the DR would only reduce the overall system peak demand by approximately 235 MW or 7.5% reduction of the system peak (from 3115 MW down to 2880 MW, with 2880 MW representing the demand for the 41<sup>st</sup> highest demand hour of the year). When in effect, if the DR were deployed in this manner, much of it would be “wasted” because it would not contribute to a corresponding reduction in the annual system peak demand.

It should be noted that the GH analysis focused on the top 40 hours due to potential constraints on the total number of hours that some of the DR measures could be dispatched in a year. For example, GH is reasonably confident that each of the various DLC, curtailment and CPP measures could be “dispatched” for up to 10 four-hour events each year without significant participant dissatisfaction or disenrollment, but experience elsewhere has shown that dispatching these DR measures more frequently than 10 times annually or for more than four hours per DR event would likely lead to lower customer satisfaction and higher disenrollment rates.

Fortunately, that not all of the DR measures in the proposed portfolio are similarly constrained by what could be called the “customer fatigue” effect. The measures that are less constrained by this effect include:

- TOU in all sectors

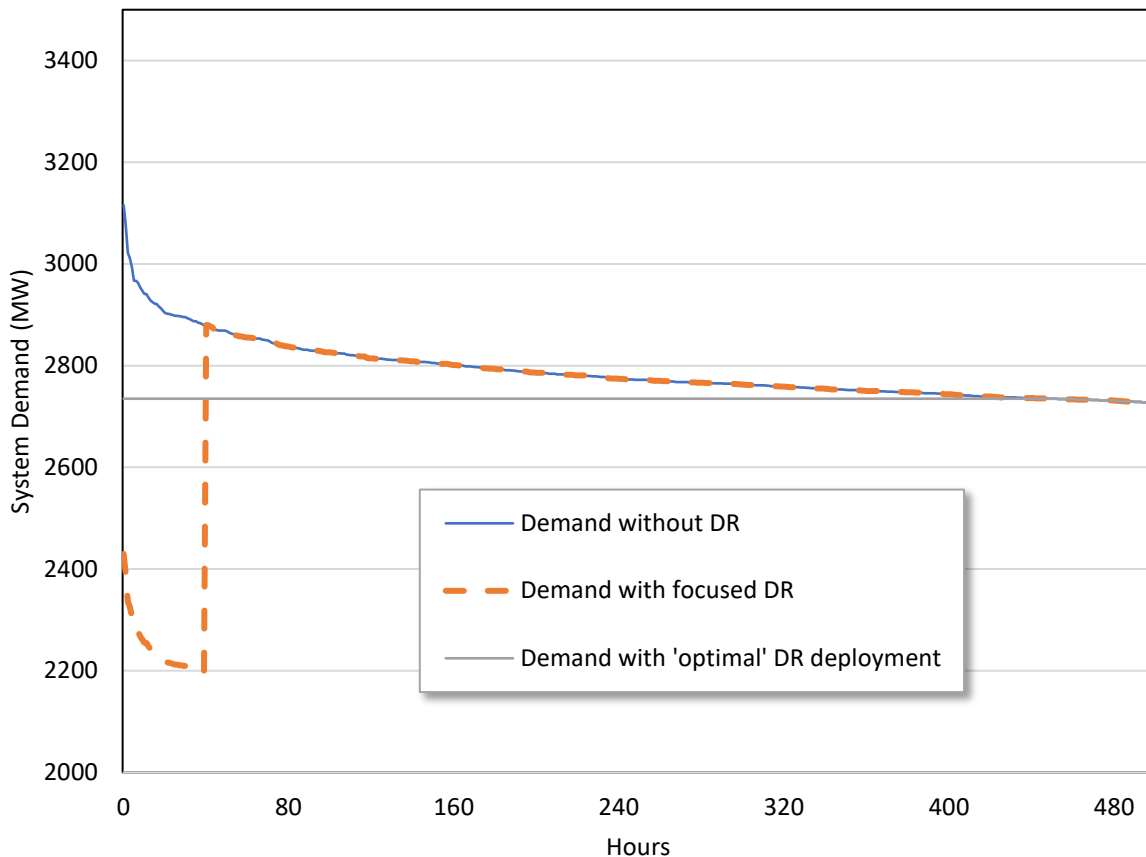
# DR Potential Study

- Res BTM Battery Dispatch
- EV Managed Charging, and
- EV V2X

The TOU measures cover more than just the top 40 demand hours by definition (since there are more than 40 on-peak hours in a year), and the other measures listed above are all dependent on equipment that would NOT be impacted (or would be significantly less impacted) by customer fatigue.

Given the availability of these relatively less constrained measures in the DR portfolio, and the relative magnitude of the expected savings for these measures, Guidehouse expects that it will be possible to “spread” the DR savings across more of the highest demand hours to further decrease the annual system peak demand (as compared to fully deploying all of the DR resources in the top 40 hours). While more detailed analysis would be required to determine the optimal deployment of the available DR resources and the resultant impact on system peak demand, a first-order approximation can be made by simply allocating the total amount of DR energy available across the highest demand hours to maximize the reduction in annual system peak demand provided by the DR. The best example of this occurs in later years and is shown in Figure 26 for 2044.

**Figure 26: Top 500 hours of system demand in 2044 with “optimal” DR deployment to minimize system peak demand**



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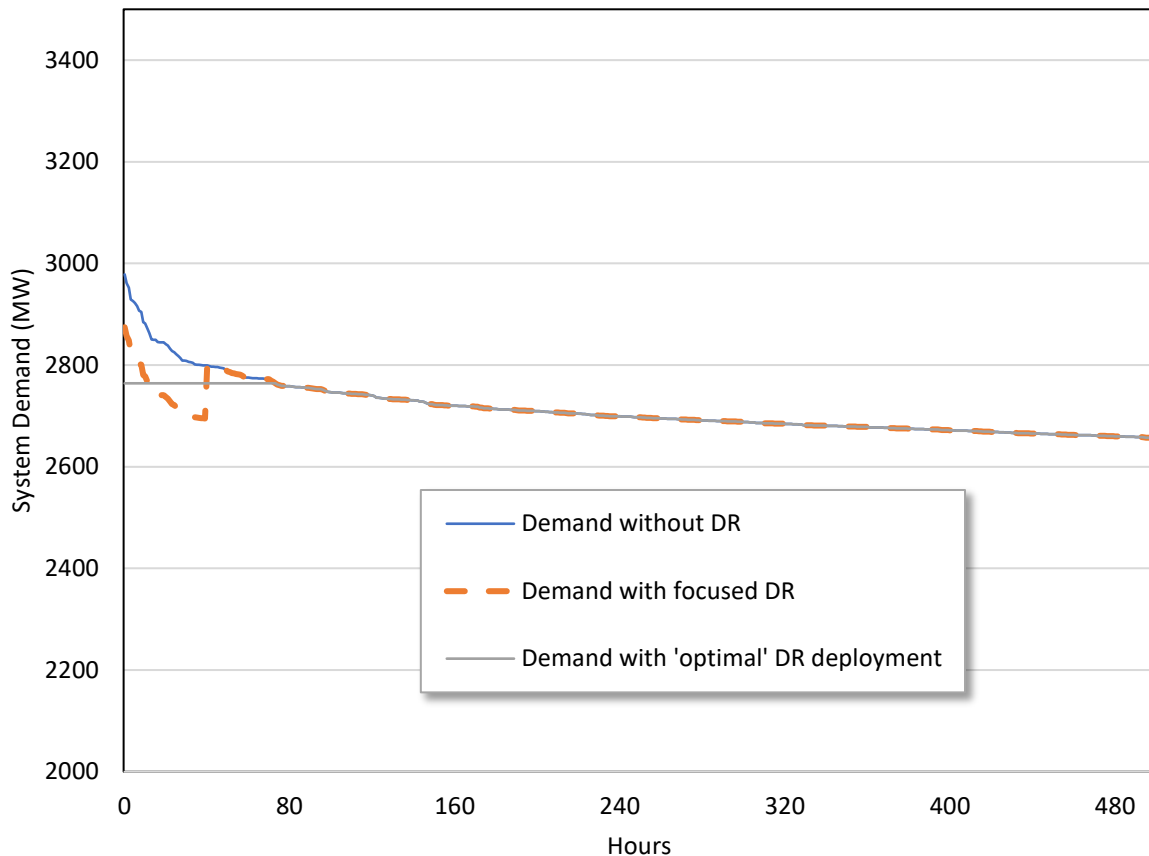
As shown in Figure 26, deploying the available DR resources optimally across the top 400 or so hours of system peak demand is expected to yield a reduction in annual peak demand of approximately 380 MW or 12% reduction of the system peak (from 3116 MW down to approximately 2735 MW). Essentially, DR would be deployed any time that the hourly peak demand is forecast to be greater than 2735 MW, with the amount of DR required in any of these hours equal to the difference between the forecast peak demand absent DR and the target peak demand of 2735 MW. In some hours, only a small amount of DR would be required and in other hours, up to the full 380 MW would be required to lower demand to the target peak demand of 2735 MW.

Further analysis beyond the scope of this report would be required to determine: 1) how closely the actual deployment of DR could match this first-order approximation, and 2) in which order the various DR measures should be deployed to minimize the overall cost of DR, based on the costs and constraints of each DR measure. Nonetheless, based on the available measures, GH is reasonably confident that a system peak demand reduction in the range of 300 – 400 MW should be achievable in 2044 through DR.

In earlier years with lower amounts of peak demand reduction, optimal DR deployment is not needed as the demand reduction is sufficiently spread across the forty event hours. For earlier years of the forecast, such as 2030, this optimal DR deployment is not reasonable, since Figure 27 shows that more load would need to be reduced at top hours to reach this smoothed system demand.

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Figure 27: Top 500 hours of system demand in 2030 with “optimal” DR deployment to minimize system peak demand



The values that result from optimal DR deployment for snapshot years are presented in Table 4-1. In years with low DR reduction potential, from 2025-2035 in the snapshot years, optimal DR is not necessary as the top 40 hours are enough to distribute the peak reduction in that year. As a result, the optimal DR reduction and the DR reduction with focused DR have the same values. However, for later years as shown in 2044 in Figure 26 and 2040 in Figure 28, less load will need to be reduced at peak hours. Starting from the 2040 snapshot year, optimal DR deployment prevents the formation of a new peak while spreading the DR savings out across the top approximately 200 hours as illustrated in Figure 28. It does not make sense to deploy optimal DR until around the snapshot year of 2040 as shown in Figure 28, where the DR reduction with the notch effect at the top hour is greater than the DR reduction with optimal deployment.

# DR Potential Study

Figure 28: Top 500 hours of system demand in 2040 with “optimal” DR deployment to minimize system peak demand

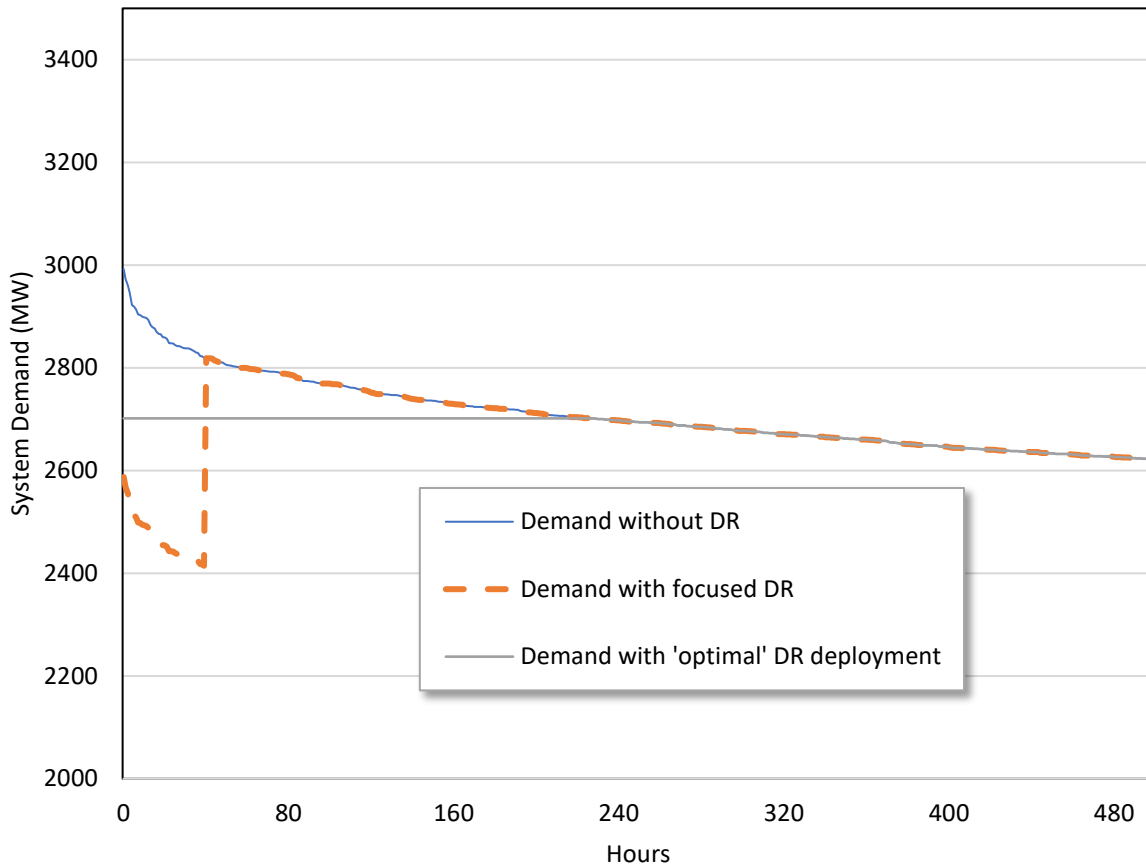


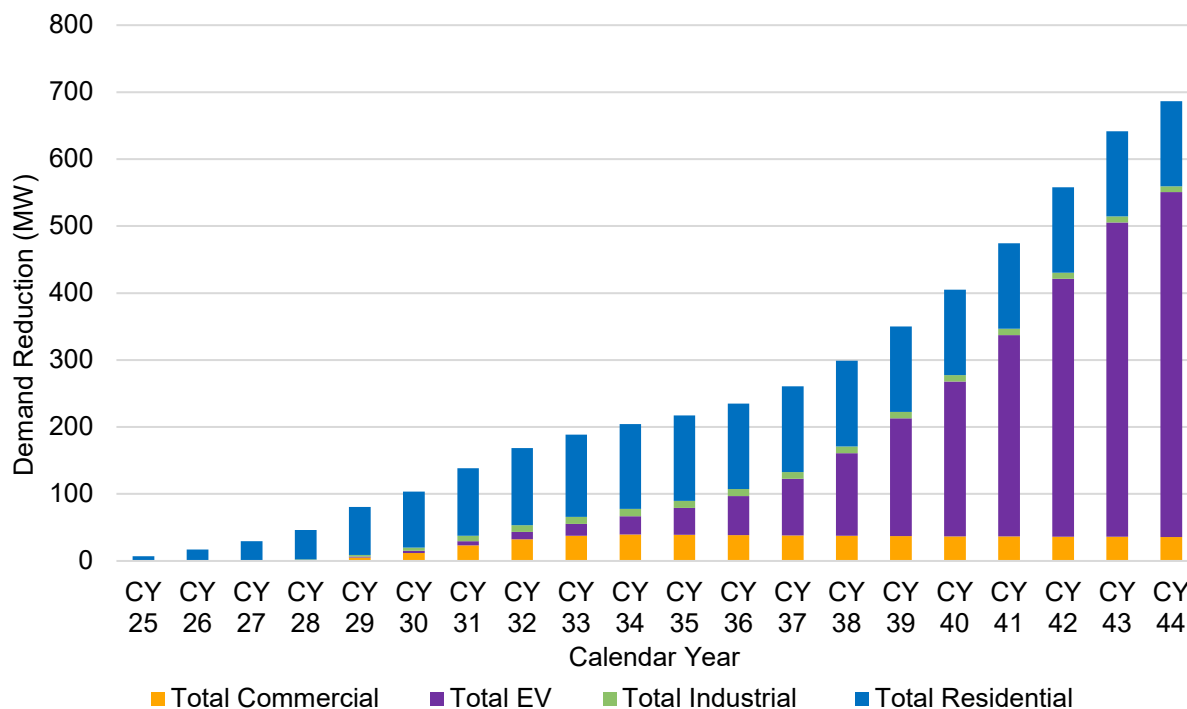
Table 4-1. DR Reduction with Optimal Deployment

Year	Demand without DR (MW)	'Optimal' DR reduction (MW)	DR reduction focused on top 40 hours (MW)
2025	2,916	7	7
2030	2,978	104	104
2035	2,940	217	217
2040	2,993	291	405
2044	3,116	380	686

Figure 28 presents the potential demand reduction over the forecast period by sector. The residential sector has the highest potential savings, followed by commercial, industrial, and then EV. Over time, EV becomes the sector with the highest potential savings due to the increase in EVs and participation in EV-related measures, primarily V2X.

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**Figure 29: Demand Reduction Over Forecast Period by Sector**



In CY 2044, the demand reduction for all measures that control end-use demand within a facility or home—therefore excluding all EV measures and BTM Battery Dispatch—represents a 3.8% reduction in the peak load of 2182 MW. The peak load excludes the peak EV load of 794 MW in CY 2044.

The levelized cost and demand reductions for CY30 and CY44 are shown in Table 27. These levelized costs include the 20% Puerto Rican cost adder discussed previously.

**Table 4-2: Levelized Cost and Demand Reduction (CY30 and CY44) by Measure**

Measure	Levelized Cost (\$/kW-yr)	CY30 Reduction (MW)	CY 44 Reduction (MW)
Com Curtailment - HVAC Control - Manual	84	0.9	0
Com Curtailment- HVAC Control - Auto DR	84	4.1	7.7
Com - TOU Rates	24	1.1	4.5
Com - CPP without enabling tech	60	1.0	0
Com - CPP with enabling tech	120	2.6	9.0
EV Managed Charging - LDV	180	1.2	68.2
EV TOU - LDV	12	0.4	12.6
EV V2X - LDV	420	0.6	346.3

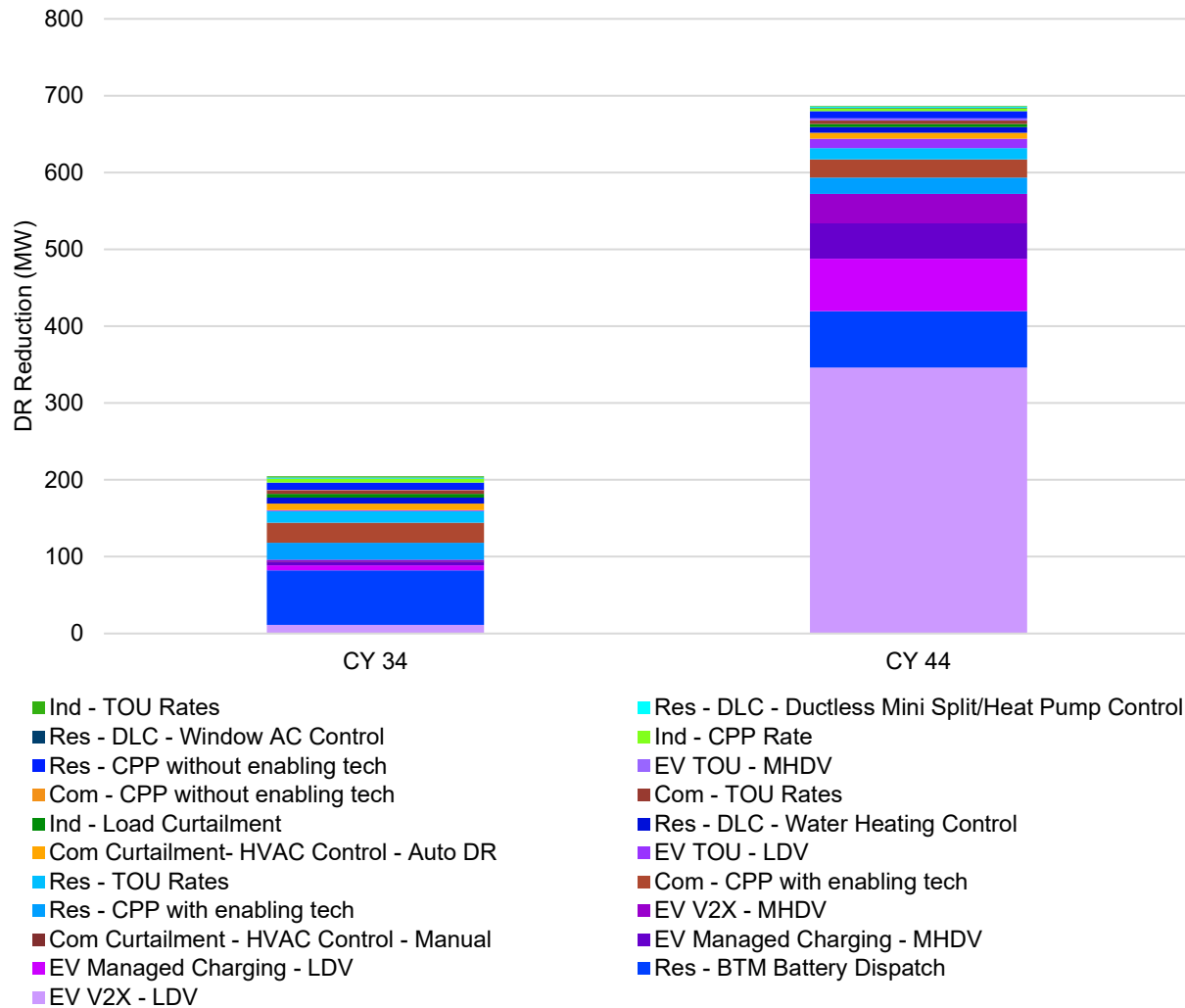
## DR Potential Study

Measure	Levelized Cost (\$/kW-yr)	CY30 Reduction (MW)	CY 44 Reduction (MW)
EV Managed Charging - MHDV	144	0.4	46.4
EV TOU - MHDV	12	0.1	3.2
EV V2X - MHDV	210	0.5	38.3
Ind - Load Curtailment	84	3.5	3.9
Ind - TOU Rates	24	0.3	1.0
Ind - CPP Rate	120	1.3	3.9
Res - DLC - Window AC Control	600	0.3	0.7
Res - DLC – Ductless Mini Split/Heat Pump Control	240	0.6	1.2
Res - DLC - Water Heating Control	240	3.9	7.3
Res - TOU Rates	12	3.5	14.6
Res - CPP without enabling tech	60	2.6	9.0
Res - CPP with enabling tech	180	6.0	21.0
Res - BTM Battery Dispatch	225.6	66.5	73.3

Figure 29 shows the annual demand reduction estimates by measure for all DR options included in the analysis, which sums to 204 MW in CY 2034 and 686 MW in CY 2044. BTM Battery Dispatch is a promising measure across all forecast years, with a reduction of 67 MW starting in CY 2030 that increases to 73 MW in CY 2043. The next most impactful measures early on in the forecast years are Residential CPP with Enabling Tech at 22 MW, Commercial CPP with enabling tech at 26 MW, and Residential TOU Rates at 15 MW in CY 2034.

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Figure 30: Demand Reduction in CY 2034 and CY 2044 by Measure

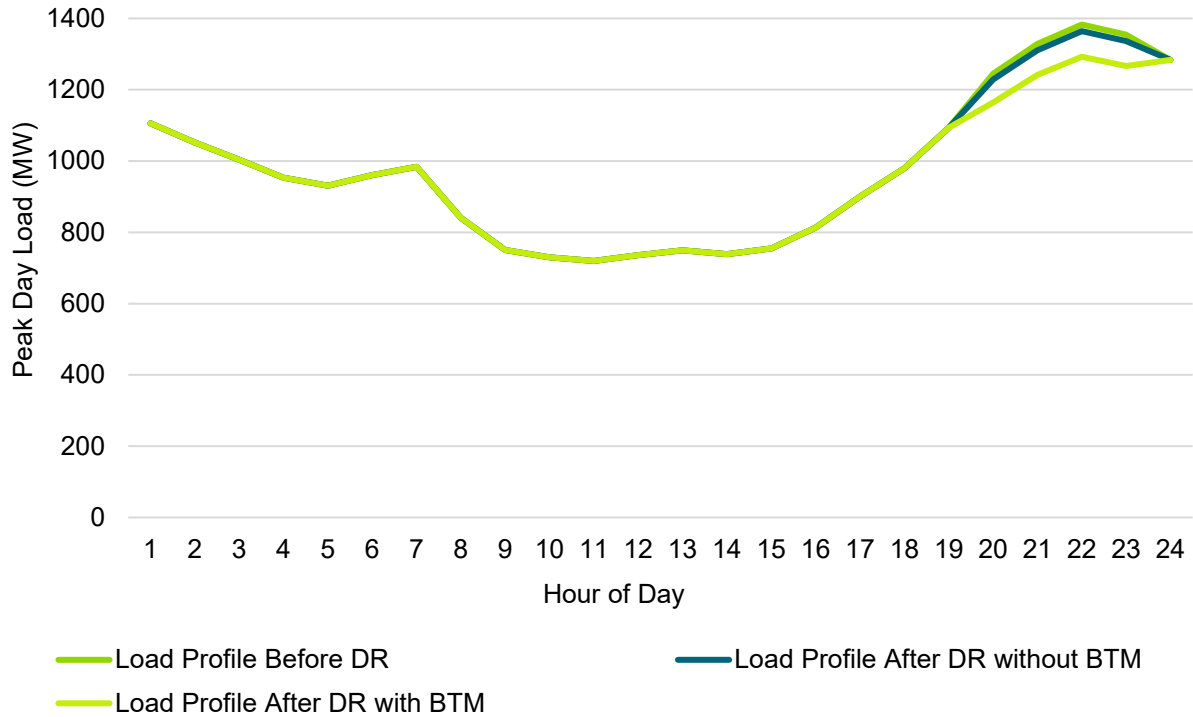


In CY 2044, the most promising measures shift due to projected development in measures like V2X and EV Managed Charging. By CY 2044, LDV V2X at 346 MW, Residential BTM Battery Dispatch at 73 MW, LDV Managed Charging at 68 MW, MHDV Managed Charging at 46 MW, and MHDV V2X at 38 MW become the five most significant contributors to the estimated DR savings, due to the projected increase of EVs in Puerto Rico. All have a levelized cost between \$120/kW-year and \$350/kW-year. After that, Residential CPP with Enabling Tech at 21 MW, Commercial CPP with Enabling Tech at 24 MW, and Residential TOU at 15 MW with Residential TOU Rates being the lowest costs of the three at \$10/kW-year.

The residential load profile on a peak day in CY 2034 is shown in Figure 30. The demand response reduction is shown over the peak four-hour period for all residential measures with and without BTM Battery Dispatch. With BTM Battery dispatch, the demand reduction is between 65 MW and 72 MW. Without BTM Battery Dispatch, the demand reduction is between 17 MW and 19 MW.

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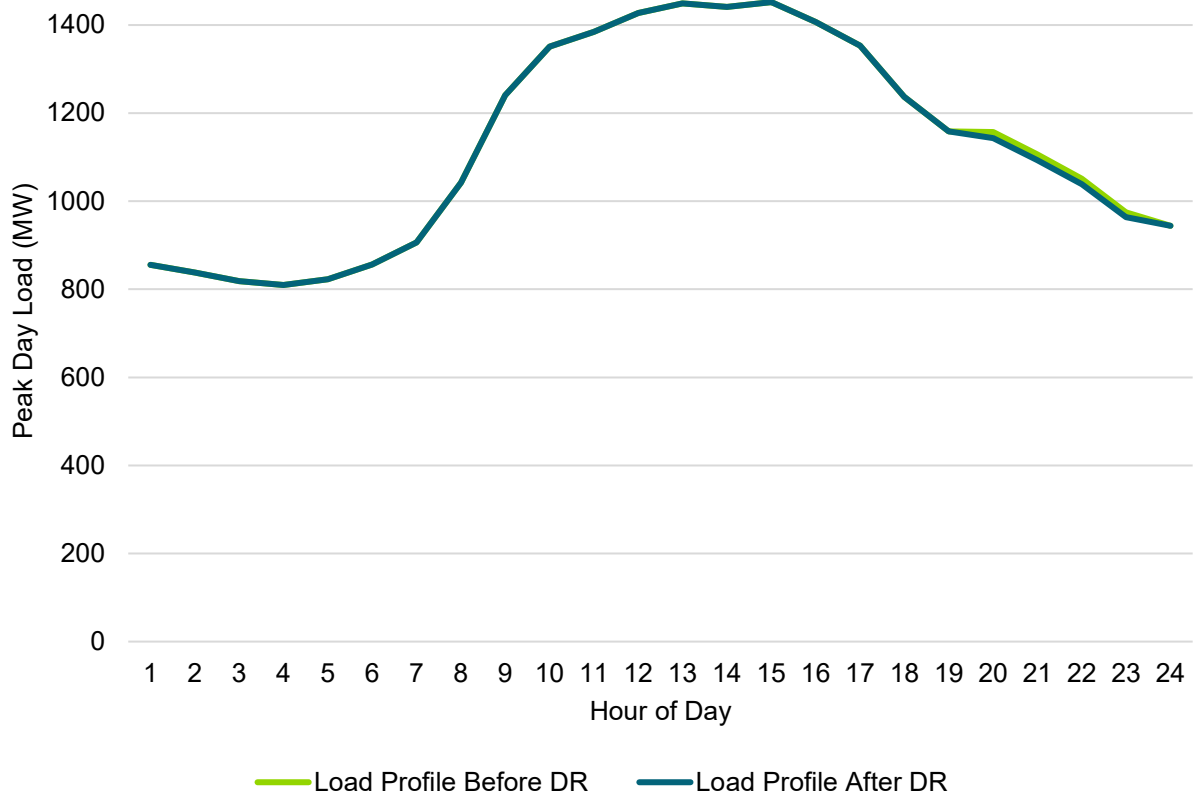
Figure 31: Residential Load Profile on a Peak Day in CY 2034



The commercial load profile on a peak day in CY 2034 is shown in Figure 31. The demand response reduction is shown over the peak four-hour period for all commercial measures. The demand reduction is between 11 and 14 MW.

# DR Potential Study

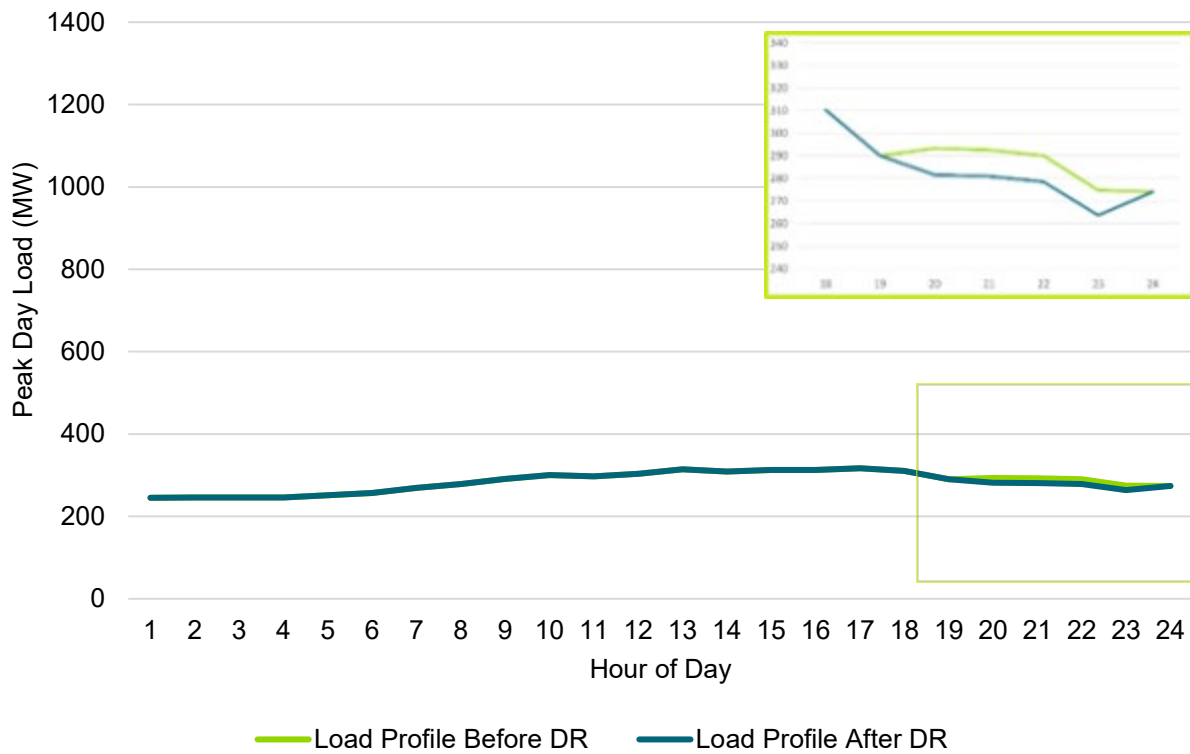
Figure 32: Commercial Load Profile on a Peak Day in CY 2034



The industrial load profile on a peak day in CY 2034 is shown in Figure 32. The demand response reduction is shown over the peak four-hour period for all industrial measures. The demand reduction fluctuates between 11 and 12 MW.

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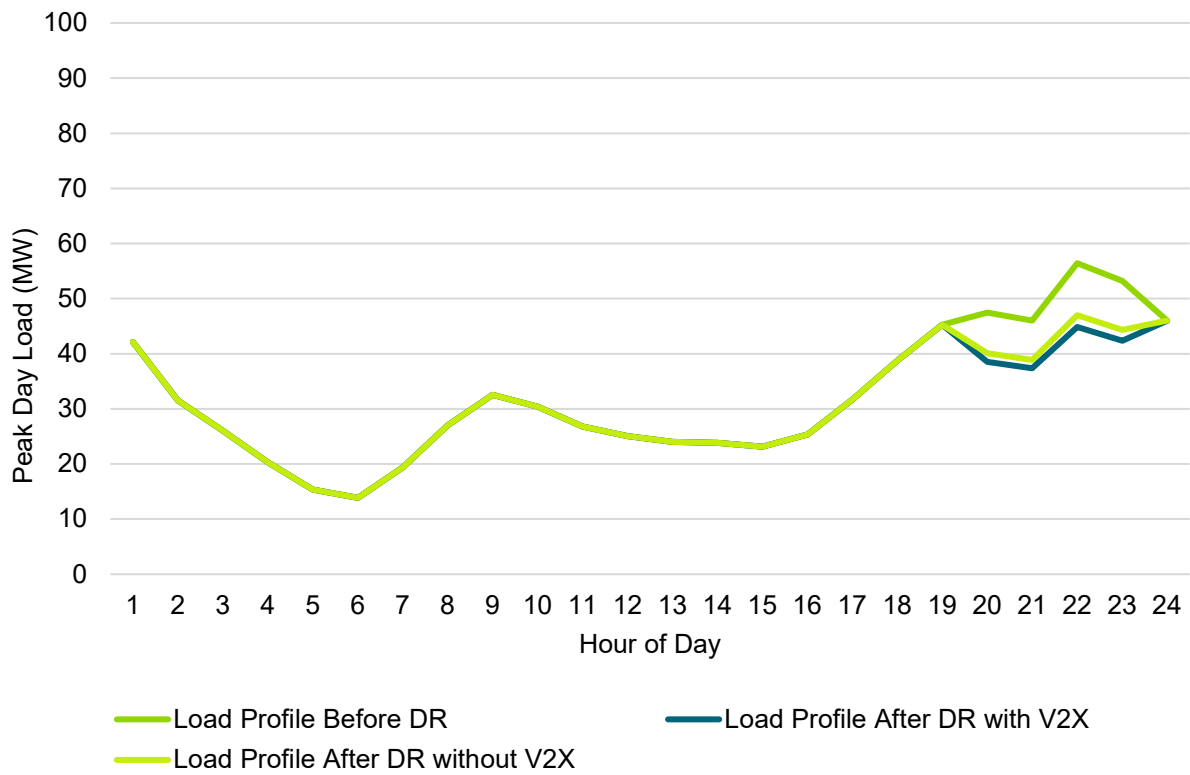
Figure 33: Industrial Load Profile on a Peak Day in CY 2034



The EV load profile on a peak day in CY 2034 is shown in Figure 33. The demand response reduction is shown over the peak four-hour period for all EV measures with and without V2X. With V2X included, the demand reduction is between 9 MW and 12 MW. Without V2X, the demand reduction is between 7 MW and 9 MW.

# DR Potential Study

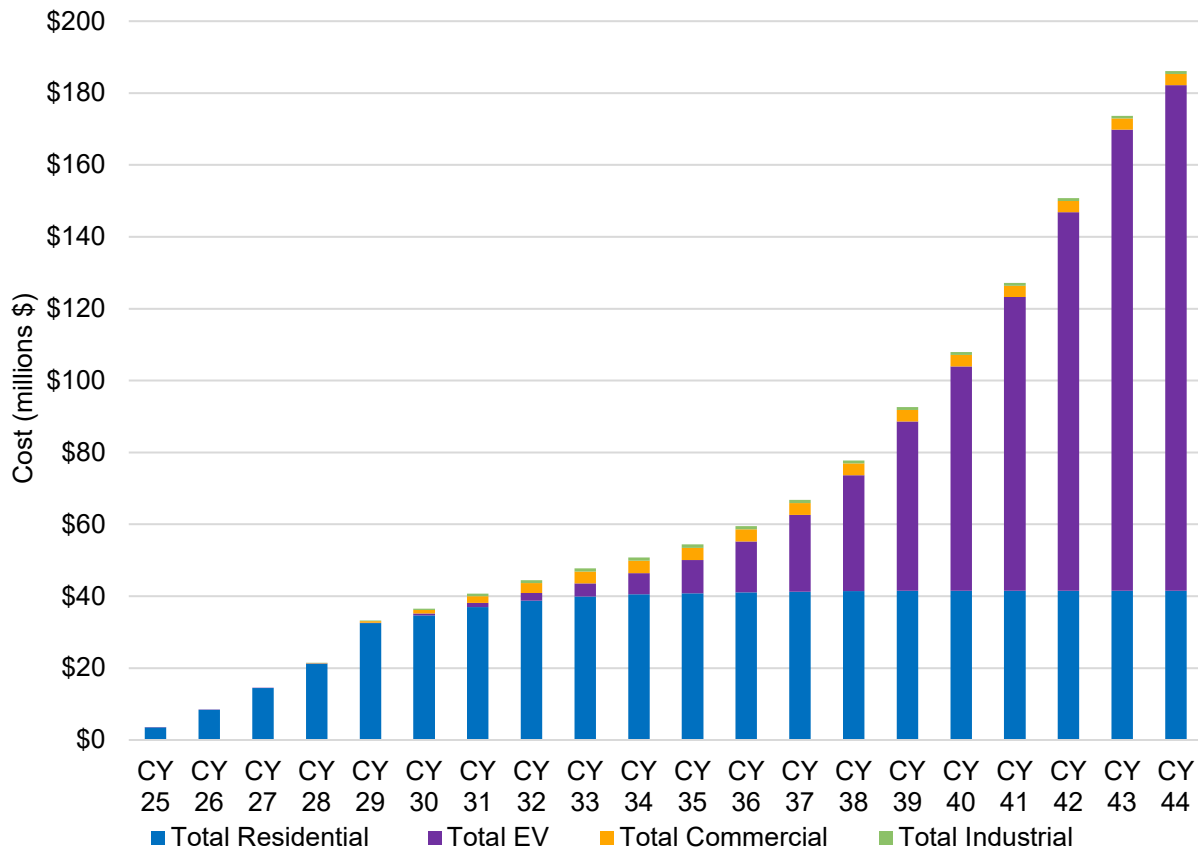
Figure 34: EV Load Profile on a Peak Day in CY 2034



The cost for each sector of implementing the DR measures discussed is shown in Figure 34. The residential sector has the highest cost over the next few years because many of the residential measures have high levelized costs as shown in Figure 35.

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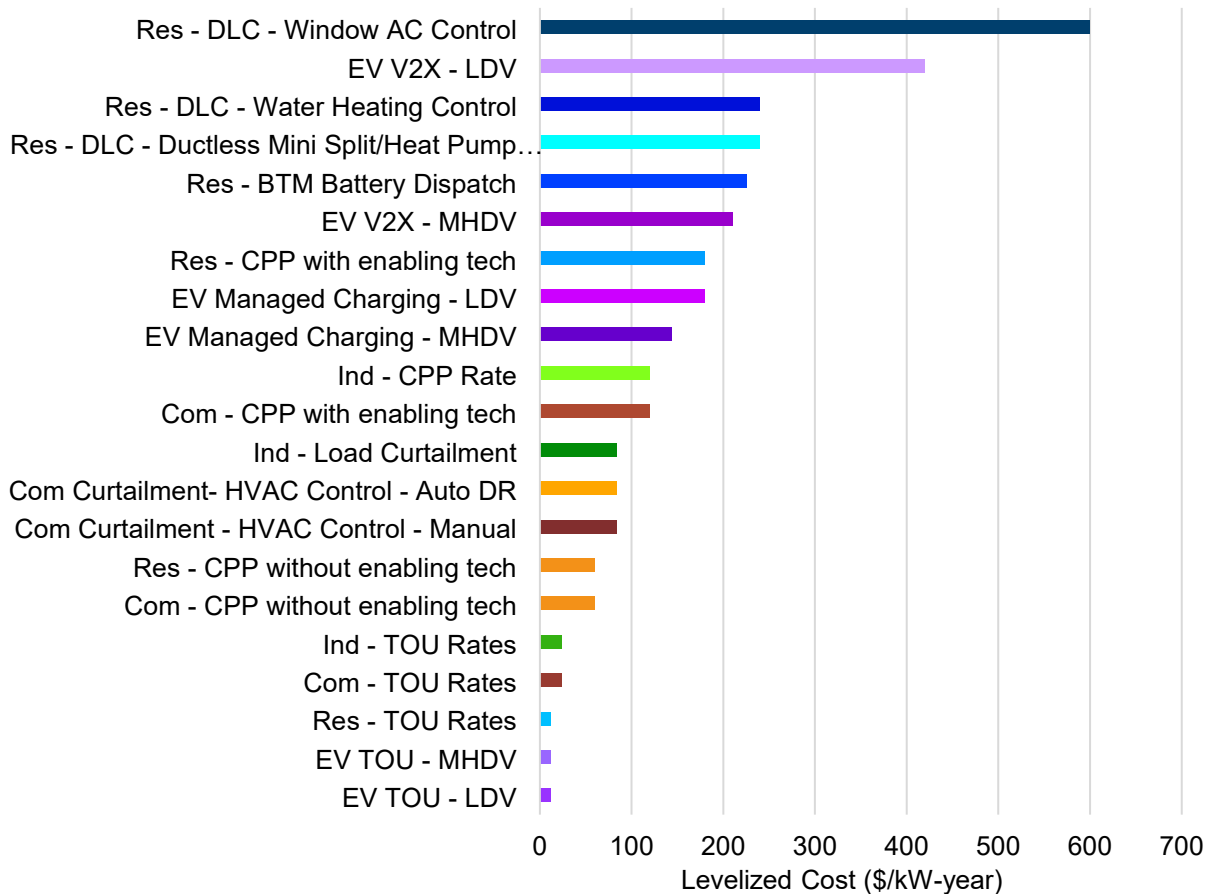
Figure 35: Cost Over Forecast Period by Sector



The comprehensive list of levelized cost values used are in Figure 35. These values include the 20% Puerto Rico Cost Adder. All Residential DLC measures, LDV and MHDV V2X, and BTM Battery Dispatch are over \$200/kW-year.

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Figure 36: Levelized Cost by Measure (\$/kW-year)

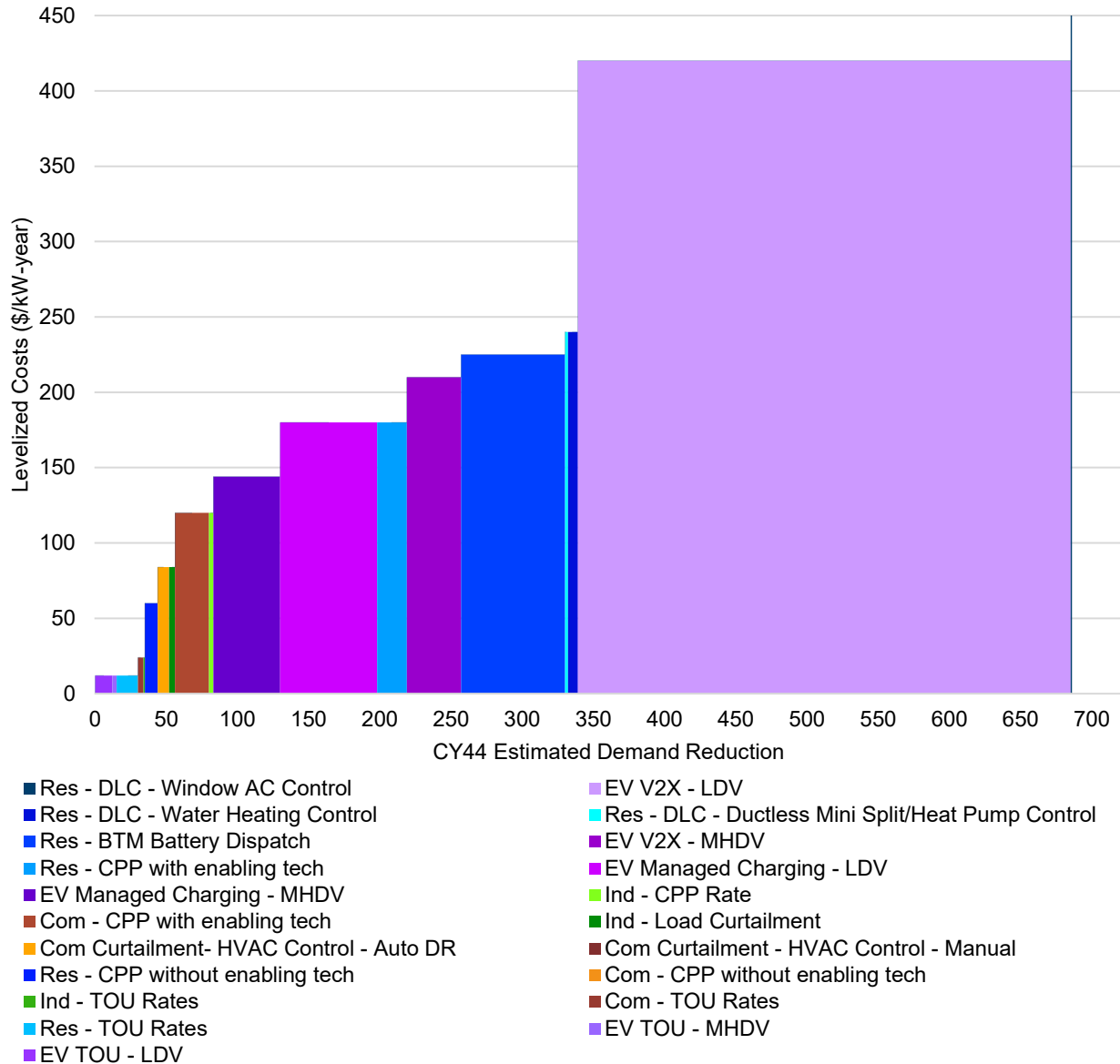


Note that most of the rate-related DR measures such as TOU rates and dynamic pricing have relatively low costs primarily because the cost of the AMI infrastructure necessary to enable TOU and dynamic pricing has NOT been included. If the cost of the AMI infrastructure were included – and the co-benefits of AMI were not considered – the various rate-related DR measures would have significantly higher costs.

Figure 36 shows the “DR Supply Stack” for CY 2044. The most significant contributors to demand response capacity for CY 2044 are BTM Battery Dispatch and V2X, but both of these are relatively high-cost measures. Excluding these and other high-cost measures, there is about 200 MW of capacity under \$200/kW-year in CY 2044.

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Figure 37: Supply Stack in CY 2044



## 4.2 Suggestions for Further Refinement

As discussed in the Introduction and Background section, there was a relative lack of comprehensive and accurate data available to inform this DR potential study, as compared with other jurisdictions. Given this relative paucity of data, Guidehouse leveraged previous DR analysis undertaken by Guidehouse in the development of the EE/DR TPP and focused its research and analytic efforts on those DR measures that are expected to provide the greatest long-term DR impact for Puerto Rico.

In terms of next steps and further refinements to this estimate of DR potential for Puerto Rico, Guidehouse suggests further research to refine the key assumptions driving the DR potential forecast,

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with a focus on the top four DR measures forecast to have the most significant contribution to the 2030 DR potential. These measures are:

- BTM Battery Dispatch,
- Residential Critical Peak Pricing with Enabling Technology,
- Commercial Critical Peak Pricing with Enabling Technology, and
- Commercial Curtailment – HVAC Control – Auto DR

In the long term, the most promising measures shift due to projected development in measures like V2X, Managed Charging, and CPP with enabling tech. These measures are:

- LDV V2X
- BTM Battery Dispatch
- LDV Managed Charging
- MHDV Managed Charging
- MHDV V2X

For the BTM DR measure, Guidehouse has received pilot information available from the BEDRP that LUMA launched in 2023. This information has informed participant impacts, among other assumptions.

For the other measures, absent better information from secondary research, we suggest that LUMA consider incorporating the most promising and cost-effective measures into to post-TPP EE/DR portfolio. By actually implementing some of these measures, even on a pilot basis, LUMA will be much better placed to refine its estimates of the long-term potential and costs of these measures, in much the same way that the BEDRP will inform future planning for the BTM DR measure.

Guidehouse primary focus in this study was identifying the “traditional” DR capacity available in Puerto Rico that could serve as a cost-effective alternative to traditional generation capacity. There are also other potential uses for DR – such as providing frequency regulation support and operating reserves – that were beyond the scope of this limited study. As time and resource permit, Guidehouse recommends that LUMA work to better understand how the current list of DR measures, and other more novel DR measures, could be modified to provide more sophisticated DR capacity for Puerto Rico.

## 4.3 Expected Evolution

In many jurisdictions in mainland United States, DR has been evolving from DR 1.0, which is primarily “shed” DR, to more advanced forms of DR (referred to as demand flexibility or DR 2.0 and 3.0) that can provide other types of grid services beyond shed DR, typically referred to as “shift”, “shape”, and

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“shimmy”.<sup>85</sup> The need for more advanced types of grid services is primarily driven by changes in the supply mix due to higher penetration of intermittent renewable energy resources, which necessitates demand to be flexible and to follow supply fluctuations to the extent possible. The DR potential assessment for LUMA considered a variety of technologies, some of which are more amenable toward providing advanced and multiple types of grid services. For example, DERs such as EVs and BTM batteries, and electric water heaters to some extent, can be dispatched or frequently and can provide daily or frequent load shifts and ancillary services (referred to as “shimmy”). The current analysis in this study estimated peak reduction potential only from these resources, but in future LUMA could consider potential estimation for multiple grid service types from these resources. Extending the use cases for EVs and BTM batteries and allowing customers to value stack from multiple revenue streams will motivate customers to participate in future demand flexibility offers. Moreover, customer hassle factor or fatigue concerns are minimal for these types of resources when compared with end-use load control at customer homes and facilities and therefore customers would be more willing to enroll in DR programs involving control of these resources. LUMA could consider building on the Battery Emergency Demand Response (BEDRP) pilot and extend the use case of the batteries for providing economic and ancillary services and for more frequent load shifts, as and when the need for these grid services arise. Similarly, LUMA should closely follow the V2X developments in the industry (especially V2G) and consider launching pilots in the area in the coming years as the technology matures since this could provide substantially high contribution not just for peak demand shed, but also for advanced types of grid services that may require more frequent dispatch with short notification and high speed of response.

LUMA could consider building a diversified portfolio for DR/demand flexibility by including other types of end-use controls and mechanisms in addition to what has been mentioned above with DERs such as EVs, BTM batteries and to some extent with water heaters. These could include smart thermostats/EMS for HVAC control, smart appliances, advanced lighting controls and other types of end-use loads with automated response capabilities. Customers may be more amenable toward voluntarily participating in these options and modifying loads in response to grid needs once the value proposition for DR/demand flexibility is established through participation of DERs such as BTM stationary batteries and EVs. The industry is moving toward a Bring Your Own (BYO) approach for DR/demand flexibility where the utility, either directly, or through third-party DR service providers is able to leverage a single common platform for controlling multiple customer side assets. LUMA could consider this for the future, as it works toward implementing the BEDRP pilot. LUMA could build on the BEDRP experience to extend the use case of batteries for non-emergency types of grid services, evolve toward using EVs as penetration of EVs increases and then consider adding other types of end-use controls at customer homes/facilities. In order for LUMA to evolve into the utility of the future, LUMA could consider closely tracking pilots/programs being considered and currently being implemented by other utilities and draw on key insights and lessons learned from these experiences on the road ahead toward building a future DR portfolio.

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<sup>85</sup> 2025 California Demand Response Potential Study, LBNL, 2019.

# DR Potential Study

## APPENDIX A

### Glossary of Terms

Term	Definition
AMI	Advanced Metering Infrastructure
BTM	Behind the Meter
BUGs	Back Up Generators
C&I	Commercial & Industrial
Control Strategy Eligibility	Determines what fraction of total devices are eligible to be controlled and can participate
CPP	Critical Peak Pricing
CY	Calendar Year
DERMS	Distributed Energy Resource Management System
DLC	Direct Load Control
DR	Demand Response
DRMS	Demand Response Management System
EDR	Emergency Demand Response
End Use Saturation	Percentage of customers with a specific end use
EV	Electric Vehicle
FCA	Fuel Charge Adjustment
FD	Flexible Demand – includes both DR measures and measures that support an increase in demand.
Impact Multiplier	Load reduction per customer. Consists of the end use saturation, unit impacts, and opt out factor.
IRP	Integrated Resource Plan
LBNL	Lawrence Berkeley National Laboratory
LDV	Light Duty Vehicles
MHDV	Medium/Heavy Duty Vehicles
NEM	Net Energy Metering
NREL	National Renewable Energy Laboratory
NWA	Non-Wires Alternative
OAT	Otherwise Applicable Tariff
Participation Hierarchy	A method to stack measures and aggregate DR impacts from multiple DR measures applicable to the same sector. Avoids double counting of DR impacts from measures targeting the same sector and end use.
Participation Multiplier	Multiplier consisting of the control strategy eligibility, participation ramp, and steady-state participation
PR-DRIFT	Puerto Rico Demand Response Impact and Forecast Tool
Steady-State Participation	Participation levels in mature programs after the option is fully ramped up
Technology-Enabled	Technology that automates customer response
TOU	Time of Use
TPP	Transition Period Plan
V1G	EV Managed Charging
V2X	Vehicle to Everything

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Term	Definition
VAST	Vehicle Analytics & Simulation Tool

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## APPENDIX B

### DR Measure Factors

Table 4-3: Static Multipliers for Residential Measures

Multiplier	Res - DLC - Window AC Control	Res - DLC - Ductless Mini Split/Heat Pump Control	Res - DLC - Water Heating Control	Res - TOU Rates	Res - CPP without enabling tech	Res - CPP with enabling tech	Res - BTM Battery Dispatch
End Use Saturation	19%	35%	94%	100%	100%	100%	100%
Steady State Participation	15%	15%	20%	20%	20%	20%	50%
Unit Impacts	0.084 kW per device	0.084 kW per device	0.1 kW per device	6%	10%	20%	1.1 kW per battery
Opt Out Factor	10%	10%	5%				20%
Levelized Cost <sup>86</sup>	\$600	\$240	\$240	\$12	\$50	\$180	\$225.6
Incentive share (%)	70%	70%	0%	0%	70%	70%	80%
Non-Incentive share (%)	30%	30%	100%	100%	30%	30%	20%

<sup>86</sup> The levelized cost values in these overview tables factor in the Puerto Rico Cost Adder (additional 20%).

# DR Potential Study

Table 4-4: Window AC Control Key Inputs

Year	Eligible Customer Count	Control Strategy Eligibility	Participation Multiplier (Ramp*Steady State Participation)
CY 2025	1,363,493	20%	0.0%
CY 2026	1,363,567	30%	0.0%
CY 2027	1,363,792	40%	0.0%
CY 2028	1,364,263	50%	1.5%
CY 2029	1,310,645	60%	3.5%
CY 2030	1,244,944	70%	7.5%
CY 2031	1,105,837	80%	11.7%
CY 2032	974,858	90%	13.5%
CY 2033	918,019	100%	15.0%
CY 2034	873,782	100%	15.0%
CY 2035	873,775	100%	15.0%
CY 2036	873,742	100%	15.0%
CY 2037	873,633	100%	15.0%
CY 2038	873,486	100%	15.0%
CY 2039	873,305	100%	15.0%
CY 2040	873,106	100%	15.0%
CY 2041	872,912	100%	15.0%
CY 2042	872,723	100%	15.0%
CY 2043	872,518	100%	15.0%
CY 2044	872,310	100%	15.0%

# DR Potential Study

Table 4-5: Ductless Mini Split/Heat Pump Control Key Inputs

Year	Eligible Customer Count	Control Strategy Eligibility	Participation Multiplier (Ramp*Steady State Participation)
CY 2025	1,363,493	20%	0.0%
CY 2026	1,363,567	30%	0.0%
CY 2027	1,363,792	40%	0.0%
CY 2028	1,364,263	50%	1.5%
CY 2029	1,310,645	60%	3.5%
CY 2030	1,244,944	70%	7.5%
CY 2031	1,105,837	80%	11.7%
CY 2032	974,858	90%	13.5%
CY 2033	918,019	100%	15.0%
CY 2034	873,782	100%	15.0%
CY 2035	873,775	100%	15.0%
CY 2036	873,742	100%	15.0%
CY 2037	873,633	100%	15.0%
CY 2038	873,486	100%	15.0%
CY 2039	873,305	100%	15.0%
CY 2040	873,106	100%	15.0%
CY 2041	872,912	100%	15.0%
CY 2042	872,723	100%	15.0%
CY 2043	872,518	100%	15.0%
CY 2044	872,310	100%	15.0%

# DR Potential Study

Table 4-6: Water Heating Key Inputs

Year	Eligible Customer Count	Control Strategy Eligibility	Participation Multiplier (Ramp*Steady State Participation)
CY 2025	1,363,493	20%	0.0%
CY 2026	1,363,567	30%	0.0%
CY 2027	1,363,792	40%	0.0%
CY 2028	1,364,263	50%	2.0%
CY 2029	1,310,645	60%	4.6%
CY 2030	1,244,944	70%	10.0%
CY 2031	1,105,837	80%	15.6%
CY 2032	974,858	90%	18.0%
CY 2033	918,019	100%	20.0%
CY 2034	873,782	100%	20.0%
CY 2035	873,775	100%	20.0%
CY 2036	873,742	100%	20.0%
CY 2037	873,633	100%	20.0%
CY 2038	873,486	100%	20.0%
CY 2039	873,305	100%	20.0%
CY 2040	873,106	100%	20.0%
CY 2041	872,912	100%	20.0%
CY 2042	872,723	100%	20.0%
CY 2043	872,518	100%	20.0%
CY 2044	872,310	100%	20.0%

# DR Potential Study

Table 4-7: Static Multipliers for Commercial Measures

Multiplier	Com Curtailment - HVAC Control - Manual	Com Curtailment- HVAC Control - Auto DR	Com - TOU Rates	Com - CPP without enabling tech	Com - CPP with enabling tech
End Use Saturation	57%	57%	100%	100%	100%
Steady State Participation	30%	30%	15%	20%	20%
Unit Impacts	33%	66%	3%	7%	14%
Opt Out Factor	10%	10%			
Levelized Cost <sup>87</sup>	\$84	\$84	\$24	\$60	\$120
Incentive share (%)	70%	70%	0%	0%	70%
Non-Incentive share (%)	30%	30%	100%	100%	30%

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<sup>87</sup> The levelized cost values in these overview tables factor in the Puerto Rico Cost Adder (additional 20%).

# DR Potential Study

Table 4-8: Manual Curtailment Key Inputs

Year	Eligible Customer Count	Control Strategy Eligibility	Participation Multiplier (Ramp*Steady State Participation)
CY 2025	123,683	80%	0.0%
CY 2026	121,849	70%	0.0%
CY 2027	119,705	60%	0.0%
CY 2028	114,801	50%	3.0%
CY 2029	109,824	40%	6.9%
CY 2030	107,554	30%	15.0%
CY 2031	105,711	20%	23.4%
CY 2032	105,622	10%	27.0%
CY 2033	105,449	0%	30.0%
CY 2034	105,198	0%	30.0%
CY 2035	104,881	0%	30.0%
CY 2036	104,427	0%	30.0%
CY 2037	103,924	0%	30.0%
CY 2038	103,414	0%	30.0%
CY 2039	102,920	0%	30.0%
CY 2040	102,458	0%	30.0%
CY 2041	102,099	0%	30.0%
CY 2042	101,676	0%	30.0%
CY 2043	101,285	0%	30.0%
CY 2044	100,923	0%	30.0%

# DR Potential Study

Table 4-9: Auto DR Curtailment Key Inputs

Year	Eligible Customer Count	Control Strategy Eligibility	Participation Multiplier (Ramp*Steady State Participation)
CY 2025	123,683	20%	0.0%
CY 2026	121,849	30%	0.0%
CY 2027	119,705	40%	0.0%
CY 2028	114,801	50%	3.0%
CY 2029	109,824	60%	6.9%
CY 2030	107,554	70%	15.0%
CY 2031	105,711	80%	23.4%
CY 2032	105,622	90%	27.0%
CY 2033	105,449	100%	30.0%
CY 2034	105,198	100%	30.0%
CY 2035	104,881	100%	30.0%
CY 2036	104,427	100%	30.0%
CY 2037	103,924	100%	30.0%
CY 2038	103,414	100%	30.0%
CY 2039	102,920	100%	30.0%
CY 2040	102,458	100%	30.0%
CY 2041	102,099	100%	30.0%
CY 2042	101,676	100%	30.0%
CY 2043	101,285	100%	30.0%
CY 2044	100,923	100%	30.0%

# DR Potential Study

**Table 4-10: Static Multipliers for Industrial Measures**

Multiplier	Ind - Load Curtailment	Ind - TOU Rates	Ind - CPP Rate
End Use Saturation		100%	100%
SS Participation	25%	15%	20%
Control Strategy Eligibility	100%	100%	100%
Unit Impacts	10%	3%	10%
Levelized Cost <sup>88</sup>	\$84	\$24	\$120
Incentive share (%)	70%	0%	0%
Non-Incentive share (%)	30%	100%	100%

**Table 4-11: Industrial TOU Rates Key Inputs**

Year	Eligible Customer Count	Participation Multiplier (Ramp*Steady State Participation)
CY 2025	588	0.0%
CY 2026	585	0.0%
CY 2027	582	0.0%
CY 2028	579	2.5%
CY 2029	576	5.8%
CY 2030	573	12.5%
CY 2031	570	19.5%
CY 2032	567	22.5%
CY 2033	564	25.0%
CY 2034	561	25.0%
CY 2035	558	25.0%
CY 2036	555	25.0%
CY 2037	552	25.0%
CY 2038	549	25.0%
CY 2039	546	25.0%
CY 2040	543	25.0%
CY 2041	540	25.0%
CY 2042	537	25.0%
CY 2043	534	25.0%
CY 2044	531	25.0%

<sup>88</sup> The levelized cost values in these overview tables factor in the Puerto Rico Cost Adder (additional 20%).

# DR Potential Study

**Table 4-12: Industrial Load Curtailment Key Inputs**

Year	Eligible Customer Count	Participation Multiplier (Ramp*Steady State Participation)
CY 2025	582	0.0%
CY 2026	579	0.0%
CY 2027	576	0.0%
CY 2028	573	2.5%
CY 2029	550	5.6%
CY 2030	523	12.5%
CY 2031	470	19.4%
CY 2032	419	22.5%
CY 2033	396	25.0%
CY 2034	377	25.0%
CY 2035	375	25.0%
CY 2036	373	25.0%
CY 2037	371	25.0%
CY 2038	369	25.0%
CY 2039	367	25.0%
CY 2040	365	25.0%
CY 2041	363	25.0%
CY 2042	361	25.0%
CY 2043	359	25.0%
CY 2044	357	25.0%

**Table 4-13: Static Multipliers for EV Measures**

Multiplier	EV Managed Charging - LDV	EV TOU - LDV	EV V2X - LDV	EV Managed Charging - MHDV	EV TOU - MHDV	EV V2X - MHDV
Steady State Participation	30%	15%	25%	30%	15%	25%
Unit Impacts	90%	11%		90%	11%	
Charger Capacity (kW)			11.2			41.5
Derating Factor			23%			23%
Levelized Cost <sup>89</sup>	\$180	\$12	\$420	\$144	\$12	\$210
Incentive share (%)	70%	0%	70%	70%	0%	70%
Non-Incentive share (%)	30%	100%	30%	30%	100%	30%

<sup>89</sup> The levelized cost values in these overview tables factor in the Puerto Rico Cost Adder (additional 20%).

# DR Potential Study

**Table 4-14: Levelized Cost (With the Puerto Rico Cost Adder) by Measure**

Measure	Levelized Cost (\$/kW-yr)
Com Curtailment - HVAC Control - Manual	84
Com Curtailment- HVAC Control - Auto DR	84
Com - TOU Rates	24
Com - CPP without enabling tech	60
Com - CPP with enabling tech	120
EV Managed Charging - LDV	180
EV TOU - LDV	12
EV V2X - LDV	420
EV Managed Charging - MHDV	144
EV TOU - MHDV	12
EV V2X - MHDV	210
Ind - Load Curtailment	84
Ind - TOU Rates	24
Ind - CPP Rate	120
Res - DLC - Window AC Control	600
Res - DLC – Ductless Mini Split/Heat Pump Control	240
Res - DLC - Water Heating Control	240
Res - TOU Rates	12
Res - CPP without enabling tech	60
Res - CPP with enabling tech	180
Res - BTM Battery Dispatch	225.6

# DR Potential Study

## APPENDIX C

### Load Forecast Data

Table 4-15: Load Forecast (MW) by Sector

Year	CY 25	CY 26	CY 27	CY 28	CY 29	CY 30	CY 31	CY 32	CY 33	CY 34
Residential	1,406	1,392	1,390	1,388	1,385	1,381	1,377	1,371	1,366	1,361
Commercial	1,097	1,105	1,130	1,145	1,148	1,147	1,145	1,136	1,128	1,120
Industrial	289	292	304	311	313	312	311	306	301	297
EV	5	6	8	11	14	19	25	32	43	56
Public Lighting	93	93	93	93	93	93	93	93	93	93
Agriculture	2	2	2	2	2	2	2	2	2	2
Other	6	6	6	6	6	6	6	6	6	6
Year	CY 35	CY 36	CY 37	CY 38	CY 39	CY 40	CY 41	CY 42	CY 43	CY 44
Residential	1,356	1,350	1,344	1,337	1,331	1,325	1,319	1,313	1,307	1,302
Commercial	1,110	1,090	1,074	1,061	1,050	1,042	1,040	1,025	1,017	1,010
Industrial	292	281	273	266	260	256	254	246	242	238
EV	74	97	126	163	210	268	337	419	513	563
Public Lighting	93	93	93	93	93	93	93	93	93	93
Agriculture	2	2	2	2	2	2	2	2	2	2
Other	6	6	6	6	6	6	6	6	6	6

# DR Potential Study

## Customer Count Data

Table 4-16: Customer Count by Customer Class

Customer Class	CY 24	CY 25	CY 26	CY 27	CY 28	CY 29	CY 30	CY 31	CY 32	CY 33
<b>Residential</b>	1,363,455	1,363,493	1,363,567	1,363,792	1,364,263	1,364,687	1,365,033	1,365,231	1,365,299	1,365,287
<b>Commercial</b>	123,723	123,683	123,705	123,886	124,110	124,270	124,340	124,365	124,261	124,058
<b>Industrial</b>	585	582	579	576	573	570	567	564	561	558
<b>Batteries</b>	54,602	68,441	81,517	92,984	101,950	122,254	126,053	128,321	130,440	132,332
<b>EVs</b>	9,621	12,899	17,031	22,255	29,000	37,873	49,513	64,833	84,790	110,718

Customer Class	CY 34	CY 35	CY 36	CY 37	CY 38	CY 39	CY 40	CY 41	CY 42	CY 43	CY 44
<b>Residential</b>	1,365,284	1,365,274	1,365,222	1,365,051	1,364,822	1,364,539	1,364,228	1,363,925	1,363,629	1,363,309	1,362,985
<b>Commercial</b>	123,762	123,389	122,855	122,264	121,663	121,083	120,538	120,116	119,619	119,159	118,733
<b>Industrial</b>	555	552	549	546	543	540	537	534	531	528	525
<b>Batteries</b>	133,923	135,153	136,202	137,064	137,711	138,134	138,326	138,485	138,624	138,744	138,845
<b>EVs</b>	144,284	187,538	242,948	313,390	402,077	512,361	647,380	809,503	999,576	1,216,082	1,333,876

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Table 4-17: EV Count by EV Class

EV Class	CY 23	CY 24	CY 25	CY 26	CY 27	CY 28	CY 29	CY 30	CY 31	CY 32	CY 33
<b>LDVs</b>	6,896	9,411	12,541	16,501	21,554	28,133	36,842	48,293	63,368	82,486	107,710
<b>MHDVs</b>	91	210	358	530	701	867	1,031	1,220	1,465	2,304	3,008

EV Class	CY 34	CY 35	CY 36	CY 37	CY 38	CY 39	CY 40	CY 41	CY 42	CY 43	CY 44
<b>LDVs</b>	140,364	182,442	236,347	304,875	391,152	498,439	629,789	787,507	972,416	1,183,039	1,297,632
<b>MHDVs</b>	3,920	5,096	6,601	8,515	10,925	13,922	17,591	21,996	27,160	33,043	36,244

# DR Potential Study

## APPENDIX D

### Study Results

Table 4-18: Demand Reduction (MW at Generator) by Measure Over Forecast Period by Calendar Year

DR Measure	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44
Res - BTM Battery Dispatch	7	17	29	43	64	66	68	69	70	71	71	72	72	73	73	73	73	73	73	73
Com - CPP with enabling tech	0	0	0	0	2	5	12	19	24	26	26	25	25	25	25	24	24	24	24	24
Res - CPP with enabling tech	0	0	0	0	3	6	13	18	20	22	22	22	22	22	21	21	21	21	21	21
Res - TOU Rates	0	0	0	0	2	3	8	12	14	15	15	15	15	15	15	15	15	15	15	15
EV V2X - LDV	0	0	0	0	0	1	2	3	6	11	19	31	49	76	114	152	200	259	316	346
Res - CPP without enabling tech	0	0	0	0	1	3	5	8	9	9	9	9	9	9	9	9	9	9	9	9
Com Curtailment-HVAC Control - Auto DR	0	0	0	1	2	4	7	8	9	8	8	8	8	8	8	8	8	8	8	8
Res - DLC - Water Heating Control	0	0	0	1	2	4	6	7	8	8	8	8	8	8	7	7	7	7	7	7
EV Managed Charging - LDV	0	0	0	0	0	1	2	4	5	7	9	12	15	20	25	32	41	51	62	68
Com - TOU Rates	0	0	0	0	1	1	3	4	4	5	5	5	5	5	5	5	5	5	4	4
Ind - CPP Rate	0	0	0	0	1	1	3	4	4	5	5	5	4	4	4	4	4	4	4	4
Ind - Load Curtailment	0	0	0	1	2	3	5	5	5	5	5	5	4	4	4	4	4	4	4	4
EV Managed Charging - MHDV	0	0	0	0	0	0	1	2	3	5	6	8	10	13	17	22	28	35	42	46
EV V2X - MHDV	0	0	0	0	0	0	1	1	2	3	4	5	7	9	13	17	22	29	35	38
Ind - TOU Rates	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
EV TOU - LDV	0	0	0	0	0	0	1	1	1	1	2	2	3	4	5	6	8	9	12	13
Res - DLC - Ductless Mini Split/Heat Pump Control	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

# DR Potential Study

DR Measure	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44
Res - DLC - Window AC Control	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
EV TOU - MHDV	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	2	2	2	3	3
Com - CPP without enabling tech	0	0	0	0	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0
Com Curtailment - HVAC Control - Manual	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
<b>Total All Sectors</b>	<b>7</b>	<b>17</b>	<b>30</b>	<b>46</b>	<b>81</b>	<b>104</b>	<b>139</b>	<b>169</b>	<b>189</b>	<b>204</b>	<b>217</b>	<b>235</b>	<b>261</b>	<b>299</b>	<b>350</b>	<b>405</b>	<b>474</b>	<b>558</b>	<b>642</b>	<b>686</b>

Table 4-19: Costs (Millions \$)<sup>90</sup> by Measure Over Forecast Period

DR Measure	CY 25	CY 26	CY 27	CY 28	CY 29	CY 30	CY 31	CY 32	CY 33	CY 34
Com Curtailment - HVAC Control - Manual	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.02	\$ 0.04	\$ 0.06	\$ 0.06	\$ 0.03	\$ 0.00	\$ 0.00
Com Curtailment- HVAC Control - Auto DR	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.05	\$ 0.12	\$ 0.30	\$ 0.48	\$ 0.55	\$ 0.64	\$ 0.61
Com - TOU Rates	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.01	\$ 0.02	\$ 0.05	\$ 0.08	\$ 0.09	\$ 0.10
Com - CPP without enabling tech	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.03	\$ 0.05	\$ 0.08	\$ 0.06	\$ 0.00	\$ 0.00
Com - CPP with enabling tech	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.19	\$ 0.49	\$ 1.20	\$ 1.98	\$ 2.49	\$ 2.70
EV Managed Charging - LDV	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.02	\$ 0.06	\$ 0.17	\$ 0.36	\$ 0.52	\$ 0.76	\$ 1.00
EV TOU - LDV	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.01	\$ 0.01	\$ 0.01	\$ 0.01
EV V2X - LDV	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.22	\$ 0.57	\$ 1.17	\$ 2.20	\$ 3.89
EV Managed Charging - MHDV	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.02	\$ 0.04	\$ 0.12	\$ 0.26	\$ 0.39	\$ 0.57
EV TOU - MHDV	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00
EV V2X - MHDV	\$ 0.00	\$ 0.01	\$ 0.02	\$ 0.03	\$ 0.06	\$ 0.08	\$ 0.11	\$ 0.20	\$ 0.30	\$ 0.46
Ind - Load Curtailment	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.06	\$ 0.13	\$ 0.27	\$ 0.38	\$ 0.39	\$ 0.40	\$ 0.38

<sup>90</sup> All costs are reported in 2023 real dollars. Section 3.3.5 of the report describes what constitutes these costs.

# DR Potential Study

DR Measure	CY 25	CY 26	CY 27	CY 28	CY 29	CY 30	CY 31	CY 32	CY 33	CY 34
Ind - TOU Rates	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.01	\$ 0.02	\$ 0.02	\$ 0.03	\$ 0.03
Ind - CPP Rate	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.07	\$ 0.15	\$ 0.31	\$ 0.45	\$ 0.51	\$ 0.54
Res - DLC - Window AC Control	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.03	\$ 0.07	\$ 0.17	\$ 0.26	\$ 0.30	\$ 0.35	\$ 0.33
Res - DLC - Ductless Mini Split/Heat Pump Control	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.02	\$ 0.05	\$ 0.12	\$ 0.19	\$ 0.22	\$ 0.25	\$ 0.24
Res - DLC - Water Heating Control	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.12	\$ 0.31	\$ 0.75	\$ 1.18	\$ 1.36	\$ 1.57	\$ 1.49
Res - TOU Rates	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.02	\$ 0.03	\$ 0.08	\$ 0.12	\$ 0.13	\$ 0.15
Res - CPP without enabling tech	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.06	\$ 0.12	\$ 0.26	\$ 0.38	\$ 0.42	\$ 0.46
Res - CPP with enabling tech	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.40	\$ 0.87	\$ 1.83	\$ 2.65	\$ 2.97	\$ 3.21
Res - BTM Battery Dispatch	\$ 1.32	\$ 3.14	\$ 5.37	\$ 7.85	\$ 11.77	\$ 12.13	\$ 12.35	\$ 12.56	\$ 12.74	\$ 12.89
<b>Total</b>	<b>\$ 1.32</b>	<b>\$ 3.15</b>	<b>\$ 5.39</b>	<b>\$ 8.20</b>	<b>\$ 13.39</b>	<b>\$ 16.09</b>	<b>\$ 19.88</b>	<b>\$ 23.30</b>	<b>\$ 26.27</b>	<b>\$ 29.06</b>

DR Measure	CY 35	CY 36	CY 37	CY 38	CY 39	CY 40	CY 41	CY 42	CY 43	CY 44
Com Curtailment - HVAC Control - Manual	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Com Curtailment- HVAC Control - Auto DR	\$0.61	\$0.60	\$0.59	\$0.58	\$0.57	\$0.57	\$0.57	\$0.56	\$0.56	\$0.55
Com - TOU Rates	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10	\$0.09	\$0.09	\$0.09	\$0.09
Com - CPP without enabling tech	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Com - CPP with enabling tech	\$2.67	\$2.63	\$2.59	\$2.56	\$2.53	\$2.51	\$2.50	\$2.47	\$2.45	\$2.43
EV Managed Charging - LDV	\$1.31	\$1.71	\$2.23	\$2.89	\$3.72	\$4.73	\$5.96	\$7.41	\$9.07	\$9.95
EV TOU - LDV	\$0.02	\$0.02	\$0.03	\$0.04	\$0.05	\$0.06	\$0.07	\$0.09	\$0.11	\$0.12
EV V2X - LDV	\$6.53	\$10.57	\$16.62	\$25.99	\$38.93	\$51.87	\$68.21	\$88.37	\$107.52	\$117.93
EV Managed Charging - MHDV	\$0.75	\$0.99	\$1.28	\$1.66	\$2.14	\$2.73	\$3.43	\$4.27	\$5.23	\$5.73
EV TOU - MHDV	\$0.00	\$0.01	\$0.01	\$0.01	\$0.01	\$0.02	\$0.02	\$0.02	\$0.03	\$0.03
EV V2X - MHDV	\$0.64	\$0.89	\$1.22	\$1.69	\$2.28	\$3.04	\$4.00	\$5.18	\$6.31	\$6.92
Ind - Load Curtailment	\$0.37	\$0.36	\$0.35	\$0.34	\$0.33	\$0.33	\$0.33	\$0.32	\$0.31	\$0.31
Ind - TOU Rates	\$0.03	\$0.03	\$0.03	\$0.03	\$0.03	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02

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DR Measure	CY 35	CY 36	CY 37	CY 38	CY 39	CY 40	CY 41	CY 42	CY 43	CY 44
<b>Ind - CPP Rate</b>	\$0.53	\$0.52	\$0.50	\$0.49	\$0.48	\$0.47	\$0.47	\$0.45	\$0.44	\$0.44
<b>Res - DLC - Window AC Control</b>	\$0.33	\$0.33	\$0.33	\$0.33	\$0.32	\$0.32	\$0.32	\$0.32	\$0.32	\$0.32
<b>Res - DLC - Ductless Mini Split/Heat Pump Control</b>	\$0.24	\$0.24	\$0.24	\$0.24	\$0.24	\$0.23	\$0.23	\$0.23	\$0.23	\$0.23
<b>Res - DLC - Water Heating Control</b>	\$1.49	\$1.48	\$1.47	\$1.47	\$1.46	\$1.45	\$1.45	\$1.44	\$1.43	\$1.43
<b>Res - TOU Rates</b>	\$0.15	\$0.15	\$0.15	\$0.15	\$0.15	\$0.14	\$0.14	\$0.14	\$0.14	\$0.14
<b>Res - CPP without enabling tech</b>	\$0.46	\$0.45	\$0.45	\$0.45	\$0.45	\$0.45	\$0.44	\$0.44	\$0.44	\$0.44
<b>Res - CPP with enabling tech</b>	\$3.20	\$3.18	\$3.17	\$3.15	\$3.14	\$3.12	\$3.11	\$3.10	\$3.08	\$3.07
<b>Res - BTM Battery Dispatch</b>	\$13.01	\$13.11	\$13.19	\$13.26	\$13.30	\$13.31	\$13.33	\$13.34	\$13.35	\$13.36
<b>Total</b>	\$32.43	\$37.35	\$44.54	\$55.41	\$70.21	\$85.48	\$104.71	\$128.28	\$151.15	\$163.52

# DR Potential Study

## APPENDIX E

### Loadshift to Back-up Generators

Many of LUMA's medium and large business customers have back-up generators to provide resiliency in the event of a power outage. Recognizing the significant DR capacity this large installed base of back-up generators could represent, LUMA included an Emergency DR program targeting these generators as part of the EE/DR TPP that was approved by the Energy Bureau.

Since receiving approval of TPP, LUMA has actively engaged with a wide variety of business customers to explore their willingness to enroll their back-up generator in the Emergency DR program. Customers have expressed interest in the program but note that the operating permit for their back-up generator limits its operation for emergency use only during power outages.

There may, however, be an opportunity to retrofit the largest of installed back-up generator with some form of exhaust aftertreatment that would allow the generator to fall under a less restrictive operating permit that would allow it to operate during DR events. There may also be an opportunity to upgrade the transfer switching equipment for these generators to provide a seamless transition to “islanded mode” from grid power (most back-up generators are “break before make” and so the power to the facility has to go off first and then the power can come back on once the generator starts and comes up to power). LUMA is contemplating providing an incentive towards these upgrades to customers' back-up generators combined with an incentive for power delivered during an emergency DR event in return for a long-term commitment from the back-up generator's manager to provide emergency DR resources to LUMA. Given that the upgrade costs are significant and largely independent of the generator size, LUMA plans to focus on the largest 5 – 10 back-up generators on the island which are expected to represent up to 100 MW of DR capacity.

This research and analysis are just in the very early stages, but Guidehouse believes it is important to consider this as a possible emergency DR resource. It is possible that some of the generators (and their switching equipment) can be upgraded economically, and the back-up generator operating permits can be revised to allow the generators to provide emergency DR capacity. On the other hand, it is also possible that there are no economic opportunities available for any of the back-up generators on the island to provide emergency DR capacity within Puerto Rico's current environmental regulatory framework. Given this uncertainty, Guidehouse believes that back-up generators should only be included as a potential DR resource if and when this resource is definitively proven to be viable or achievable. As such, Loadshift to Back-up Generators has not been included in the DR potential estimates given elsewhere in the report.

Based on preliminary Guidehouse analysis, Loadshift to Back-up Generators may be able to contribute 122MW of emergency DR capacity starting in CY 2027 and staying constant for the entire forecast period. With a levelized cost of \$70 / kW-year, the estimated cost for this emergency DR capacity would be approximately \$24 million annually.

Guidehouse recommends that LUMA engage with an environmental specialist with knowledge of the local generation permitting process to determine whether and how the operating permits for the largest BUGS could be revised to allow operation during system emergencies (i.e., when supply is not expected to be able to meet demand and rolling outages are imminent). Guidehouse expects that this would require some sort of modifications to the generator – such as exhaust after-treatment – and also to the

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generation interconnection with the host facility – such as a synchronous transfer switch. Understanding whether or not the permits can be revised, and what needs to get done and how much this would cost in order to revise the permits is critical to inform LUMA's further efforts on this DR opportunity.