EM&V Report for the PowerShare® Program 2022-2023

Prepared for:

Duke Energy Carolinas

FINAL

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Executive Summary

Duke Energy Carolina's (DEC) PowerShare program is a demand response (DR) program, offered to commercial and industrial customers, that provides a financial incentive to reduce their electricity consumption when called upon by DEC. This report includes the methodology and results of the evaluation performed by Guidehouse Inc. (Guidehouse) for the period of June 1, 2022 through May 31, 2023. The evaluation included an impact assessment to quantify participant load curtailment during DR events.

The PowerShare program offers customers three options for participation:[1]

- **Mandatory Curtailment:** Participants enrolled in the Mandatory Curtailment Option are required to reduce and maintain load during each Mandatory Curtailment Period to the level specified in their PowerShare contract. Curtailment is activated when Duke Energy experiences capacity constraints. Capacity Credits are paid monthly and Energy Credits are paid for the load curtailed during each event.
- **Voluntary Curtailment:** Participants enrolled in the Voluntary Curtailment Option can take part in Voluntary Curtailment Periods on a per-event basis. If a participant elects to participate in an event, they should reduce and maintain their load to a pre-specified level. A Voluntary Curtailment Period is initiated at Duke Energy's discretion. Notification of the event is typically provided one business day in advance. Energy Credits are paid for the load curtailed during each event.
- **Generator Curtailment:** Participants enrolled in the Generator Curtailment Option are required to transfer load from their Duke Energy power source to a private generation source during each Generator Curtailment Period. A Generator Curtailment Period is implemented when Duke Energy experiences capacity constraints. Capacity Credits and Energy Credits are paid for the load transferred to the generator during readiness tests and events.

The PowerShare program is designed to encourage the participating organizations to reduce their electricity consumption. Customers may qualify for the program if they can provide 100 kW in curtailable load (for the Mandatory and Voluntary Curtailment options) or if they can transfer 100 kW of load from the utility source to a generator (for the Generator Curtailment option). Mandatory Curtailment Periods and Generator Curtailment Periods are limited to 10 hours per event and 100 hours per year, while Voluntary Curtailment Periods may exceed these limits.

Duke Energy contracts with Schneider Electric, a firm that provides energy management services, to calculate monthly customer settlements for the PowerShare program. The PowerShare settlements are calculated with the use of Schneider Electric's Energy Profiler Online (EPO), a third-party hosted software application. EPO uses participant interval data, EPO-generated participant baselines, and a set of program option-specific calculations to determine the event energy (kWh) and monthly capacity (kW) values that determine participant settlement payments.

During 2022-2023, the PowerShare program called two emergency DR events for 160 accounts, most of whom (41 percent) were in the manufacturing market segment. Both events were called during Winter 2022 (December 24 and December 26, 2022).

[1] This summary of participation options was drawn directly from the PowerShare program brochure in July 2023. The PowerShare program brochure may be found here: https://www.duke-energy.com/business/products/powershare

For the impact evaluation, Guidehouse used advanced metering infrastructure (AMI) consumption data (kWh) for DEC participants to estimate demand response impacts on event days. To do so, Guidehouse selected a baseline approach that minimizes the root mean squared error (RMSE) between actual and predicted load on specific event-like days across all participants. Guidehouse then calculated a baseline for each event participant for each event and estimated demand response impacts for each participant by taking the difference between estimated baseline demand and actual observed demand during event hours.

Key Findings and Recommendations

Impact Findings

Table ES-1 shows the average estimated program impacts using the baseline testing approach for the two Emergency Events called between June 1, 2022 and May 31, 2023. Accounts in both the Generator and Mandatory enrollment options were called for the Emergency Events. The Emergency Events on December 24 and December 26 yielded an average total load reduction of 360.02 MW during event hours.

Table ES-1. Total Estimated Load Reductions for 2022-2023 DEC PowerShare Events

Date	Accounts Called*	Total Reported Load Reduction (MW)	Total Estimated Load Reduction (MW)	Margin of Error (± MW, 90% CI)	Relative Precision (± %)
12/24/2022	160	330.22	357.20	16.69	5%
12/26/2022	160	333.94	362.84	16.82	5%
Overall	**160**	**332.08**	**360.02**	**16.75**	**5%**

*Guidehouse estimated Emergency Event impacts for 158 of 160 accounts called, as two accounts were missing AMI data on the Emergency Event days.

Source: Guidehouse analysis of participant AMI data and event settlement data

The key findings of Guidehouse's impact evaluation of the DEC PowerShare program for 2022-2023 are:

- **Guidehouse estimated an average total curtailment of 360.02 MW across the two Emergency Events called in 2022-2023, resulting in a 108 percent realization rate.** The two Emergency Events, which were called for customers enrolled in the Mandatory Curtailment and Generator Curtailment program options, yielded estimated total load shed of 357 MW on December 24 and 363 MW on December 26. This estimated load curtailment exceeded reported load curtailment received from Duke Energy, with a realization rate of 108 percent when comparing estimated to reported load curtailment across the two events.

- **In aggregate, Emergency Events result in reliable and effective load curtailment during the event hours.** When assessing event participation, Guidehouse examined aggregate load shapes and realization rates for load curtailment estimated for each customer for each event. Inspection of aggregate load shapes revealed a program-wide response to the Emergency Events, with a marked reduction in load throughout the duration of the two events. In addition, approximately 90 percent of customers had a realization rate (estimated impacts/reported imacts) greater than 67 percent.

- **A limited number of customer accounts had little to no demand response to the Emergency Events.** When estimating load curtailment for the two Emergency Events, Guidehouse observed that realization rates for a subset of customers (12 accounts of the 160 accounts called) were less than 33 percent, indicating a large gap between anticipated curtailment and estimated curtailment. Consistent with this finding, Guidehouse's inspection of aggregate load shapes for these customer accounts revealed a weak response to the called events, with almost no change in observed load during the event hours.

Based on the findings above, Guidehouse developed the following recommendations:

- **Given the reliable and effective load curtailment during Emergency Events, continue to call events when system capacity is constrained.** Based on estimated reductions in load across the two Emergency Events, the events are capable of encouraging load shed among enrolled participants. As such, Guidehouse recommends that Duke Energy continue to call Emergency Events as a means of shedding load during times of system capacity constraints.

- **Consider investigating what drove lower event participation for a subset of accounts.** A limited number of accounts exhibited little to no response to the Emergency Events. Since the two called Emergency Events overlapped with December holiday season, an initial hypothesis of what drove a weak response for a subset of accounts was that the customers' load was already at or below their contract demand (i.e., the demand they must maintain during events). Investigation of aggregate load shapes against contract demand did not support this hypothesis, with average observed load leading up to and during the event exceeding contract demand amounts. Gathering an understanding of what drove lower participation amongst a subset of accounts will give Duke Energy an indication of what, if any, program components may be improved to encourage participation during Emergency Events.

1. Program Description

Duke Energy Carolinas' (DEC) PowerShare program is a demand response (DR) program, offered to commercial and industrial customers, that provides customers a financial incentive to reduce their electricity consumption when called upon by DEC. This report includes the methodology and results of the evaluation performed by Guidehouse Inc. (Guidehouse) for the period of June 1, 2022 through May 31, 2023. The evaluation included an impact assessment to quantify participant load curtailment during DR events.

The PowerShare program offers customers three options for participation, summarized in Table 1-1 below:[2]

- **Mandatory Curtailment:** Participants enrolled in the Mandatory Curtailment Option are required to reduce and maintain load during each Mandatory Curtailment Period to the level specified in their PowerShare contract. Curtailment is activated when Duke Energy experiences capacity constraints. Capacity Credits are paid monthly and Energy Credits are paid for the load curtailed during each event.
- **Voluntary Curtailment:** Participants enrolled in the Voluntary Curtailment Option can take part in Voluntary Curtailment Periods on a per-event basis. If a participant elects to participate in an event, they should reduce and maintain their load to a pre-specified level. A Voluntary Curtailment Period is initiated at Duke Energy's discretion. Notification of the event is typically provided one business day in advance. Energy Credits are paid for the load curtailed during each event.
- **Generator Curtailment:** Participants enrolled in the Generator Curtailment Option are required to transfer load from their Duke Energy power source to a private generation source during each Generator Curtailment Period. A Generator Curtailment Period is implemented when Duke Energy experiences capacity constraints. Capacity Credits and Energy Credits are paid for the load transferred to the generator during readiness tests and events.

Table 1-1. PowerShare Participation Options

Participation Option	Conditions Triggering Curtailment Periods	Timing of Curtailment Periods	Maximum Duration of Curtailment Periods
Mandatory Curtailment (PS-M)	System capacity constraints	Anytime	10 hours/period 100 hours/year
Voluntary Curtailment (PS-V)	System capacity constraints, mutual economic opportunity	Anytime	At DEC's Discretion
Generator Curtailment (PS-G)	System capacity constraints	Anytime	10 hours/period 100 hours/year

Source: Guidehouse analysis of Duke Energy program brochure

The PowerShare program is designed to encourage the participating organizations to reduce their electricity consumption during select curtailment events. Customers may qualify for the program if they can provide 100 kW in curtailable load (for the Mandatory and Voluntary

[2] This summary of participation options was drawn directly from the PowerShare program brochure in July 2023. The PowerShare program brochure may be found here: https://www.duke-energy.com/business/products/powershare

Curtailment options) or if they can transfer 100 kW of load from the utility source to the generator (for the Generator Curtailment option). Mandatory Curtailment Periods and Generator Curtailment Periods are limited to 10 hours per event and 100 hours per year, while Voluntary Curtailment Periods may exceed these limits.

Duke Energy contracts with Schneider Electric, a firm that provides energy management services, to calculate monthly customer settlements for the PowerShare program. The PowerShare settlements are calculated with the use of Schneider Electric's Energy Profiler Online (EPO), a third-party hosted software application. EPO uses participant interval data, EPO-generated participant baselines and a set of program option-specific calculations to determine the event energy (kWh) and monthly capacity (kW) values that determine participant settlement payments.

The following two subsections provide additional detail on program enrollment, as well as events called between June 1, 2022 and May 31, 2023.

1.1 Program Enrollment

A total of 160 accounts were called to curtail in the PowerShare program during 2022-2023. Of these accounts, 152 were enrolled in the Mandatory Curtailment program option and nine were enrolled in the Generator Curtailment program option. For 2022-2023, all 160 accounts were called to curtail load for at least one event. There were two Emergency Events called during 2022-2023, during which all accounts enrolled in the Mandatory Curtailment and Generator Curtailment program options were called to participate. Table 1-2 provides an overview of PowerShare program enrollment and participation by program option.

Table 1-2. PowerShare Participation by Program Option

Program Option	Number of Called Accounts	Number of Emergency Events
Mandatory Curtailment	152	2
Voluntary Curtailment	-	-
Generator Curtailment	8	2
Overall	**160**	**2**

Source: Guidehouse analysis of event settlement data

The majority of accounts called were comprised of customers in the Manufacturing market segment (41 percent of total enrollments), shown in Table 1-3. The State and Local Government and Process Industry market segments were also common, making up 19 and 13 percent of total enrollments.

Table 1-3. Participation by Market Segment

Market Segment	Number of Enrolled Accounts	Percent of Enrolled Accounts
Education	1	1%
Commercial Real Estate, Real Estate Investment Trusts, and Hospitality	2	1%
Hospitals and Healthcare	3	2%
Retail and Distribution	5	3%
Other	6	4%

Market Segment	Number of Enrolled Accounts	Percent of Enrolled Accounts
Transportation	10	6%
Data Centers and Telecom	16	10%
Process Industry	21	13%
State and Local Government	31	19%
Manufacturing	65	41%
Total	**160**	**100%**

Source: Guidehouse analysis of participant cross-sectional data

1.2 PowerShare Events

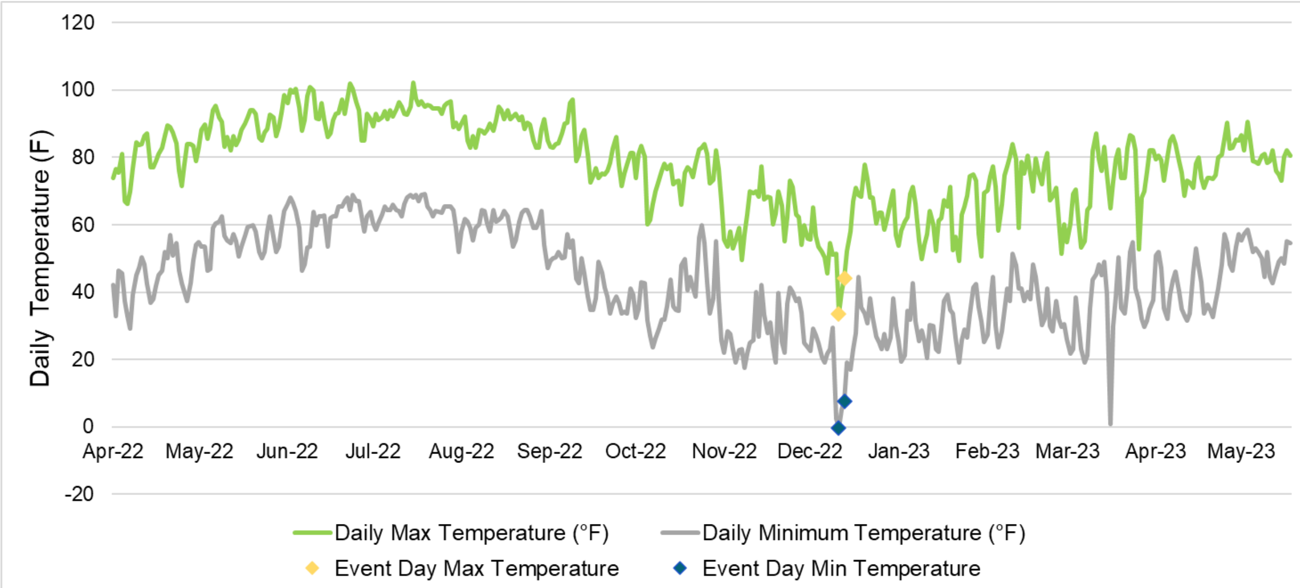
During 2022-2023, DEC called 14 events (6 Summer, 8 Winter), which are listed in Table 1-4. Twelve events called during the season were test events for accounts enrolled in the Generator Curtailment program option. The remaining two events, called on December 24 and December 26, were Emergency Events in which Mandatory Curtailment and Generator Curtailment program participants were called to curtail. Figure 1-1 illustrates that these events were called during the two coldest winter days in 2022-2023. **The evaluation results in this report focus only on the two Emergency Events**.

Table 1-4. DEC PowerShare Events, June 2022 - May 2023

Season	Event Date	Event Time (EST)	Type	Groups Called	Accounts Called
Summer	6/15/2022	3 pm – 4 pm	Test	PS-G	9
	7/20/2022	3 pm – 4 pm	Test	PS-G	9
	8/17/2022	3 pm – 4 pm	Test	PS-G	9
	9/21/2022	3 pm – 4 pm	Test	PS-G	8
	10/19/2022	9 am – 10 am	Test	PS-G	8
Winter	11/16/2022	9 am – 10 am	Test	PS-G	8
	12/21/2022	9 am – 10 am	Test	PS-G	8
	12/24/2022	4 am – 12 pm	Emergency	PS-G & PS-M	160
	12/26/2022	6 am – 10 am	Emergency	PS-G & PS-M	160
	1/18/2023	9 am – 10 am	Test	PS-G	8
	2/15/2023	9 am – 10 am	Test	PS-G	8
	3/15/2023	9 am – 10 am	Test	PS-G	8
	4/19/2023	9 am – 10 am	Test	PS-G	8
Summer	5/17/2023	9 am – 10 am	Test	PS-G	8

Source: Guidehouse analysis of event settlement data

Figure 1-1. Time Series of Weather and Emergency Events



Source: Guidehouse analysis of event settlement data and NOAA weather data

2. Impact Evaluation

This section summarizes the impact evaluation methods utilized to estimate curtailment across the events called for the PowerShare program. The following subsections describe the research objectives, data collection, and analytical steps in greater detail.

2.1 Key Research Objectives

The research objectives of this evaluation were to estimate the demand response (kW) delivered by PowerShare participants on Emergency Event event days from June 1, 2022 through May 31, 2023. Specifically:

1. Estimate verified demand (kW) impacts using a baseline testing approach (described in Section 2.4 and Appendix A. Detailed Impact Evaluation Methodology) among seven regression-based baselines and 23 customer baselines (CBLs). These impacts include:

    a. Average kW demand impact per customer for each event, and on average across all events

    b. Total program kW demand impact for each event, and on average across all events

2.2 Data Sources

The data sources used for the impact evaluation include:

- **Participant Advanced Metering Infrastructure (AMI) Data:** Half-hourly consumption data for all participants for the entire evaluation period and for the 45 days immediately preceding (i.e., 2022-04-15 through 2023-05-31).
- **Participant Cross-Sectional Data:** This data includes curtailment option, industry type, and other firmographic information.
- **Event Tracking Data:** This data includes information on the type and timing of each PowerShare event called, as well as performance data for each participant for each event, including reported curtailment (in kW) during each of the 14 called events.
- **National Oceanic and Atmospheric Administration (NOAA) Weather Data:** Guidehouse collected data for 38 weather stations from NOAA, which includes hourly dry bulb temperature and relative humidity for select areas in North Carolina and South Carolina.

2.3 Weather Data at Customer Sites

Guidehouse estimated 2022-2023 weather experienced by each participant by collecting historical data from NOAA for 38 weather stations throughout North Carolina and South Carolina.[3] After collecting data from weather stations, Guidehouse assigned weather data to each customer by selecting the closest weather station by ZIP code for each customer site.

[3] See https://www.ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/quality-controlled-local-climatological-data-qclcd

2.4 Estimating Verified Impacts Using a Baseline Testing Approach

Once all data was compiled, Guidehouse conducted baseline testing to inform the estimation of program impacts. The objective of this task was to select the most accurate method to construct baseline (i.e., counterfactual) load profiles for each participant, which are compared to actual in-event load to determine total load curtailment. Guidehouse selected a baseline approach by testing a variety of potential methods and selecting the best performing method that showed the smallest root mean squared error (RMSE) between actual and predicted load on specific event-like days[4] across all participants. This process is detailed in Appendix A.1 Estimating Verified Impacts Using a Baseline Testing Approach and involved:

- **Testing of Candidate Baseline Methods.** Guidehouse tested a set of Customer Baselines (CBLs) and regression specifications, with and without day-of-adjustment, to determine the approach to be used for estimating verified impacts.
- **Estimating Verified Impacts.** Guidehouse estimated baseline demand using the best-performing baseline approach. Guidehouse then estimated verified impacts by calculating the difference between observed in-event demand and estimated baseline demand for each participant. Guidehouse estimated verified impacts for each event in the evaluation period, as well as the average across all events, for each customer and for all customers in aggregate (i.e., the program total).

Table 2-1 provides a description of the best-performing baseline method for the winter season, which was then used to estimate baseline demand for each account called to participate in the two called Emergency Events. In total, Guidehouse tested 23 CBLs and seven regression models, using three event-like non-event days in the winter season.[5]

Table 2-1. Winning Baseline Methods for Estimating Verified Impacts

Season	Winning Method	Day-of Adjustment?	Method Description
Winter	7-of-7 CBL	No	Baseline (i.e., counterfactual) demand for each event day's hour is the average of each respective hour's demand observed over the seven non-holiday, non-event weekdays immediately preceding the event day.

Note: With the exception of the December 24 emergency event, Guidehouse removed weekend days from the analysis dataset, as all but one event were called on weekdays, and demand on weekend days were a departure from typical weekday demand for most participants. Therefore, for baseline accuracy, the two winning CBL methods used data looking back across a set of preceding weekdays.

Source: Guidehouse

It is important to note that Guidehouse's winning baseline methods do not include any day-of adjustments[6] to demand for program participants. Emergency Events called on December 24

[4] Event-like days are defined on the basis of the day's temperature profile. For each event, a test day is selected from the pool of non-event days which has a temperature profile most like the given event day.

[5] Three event-like non-event days were selected for each account for each season based on similarity of observed weather with the event days the participant was called to participate in. Different event-like non-event days were selected for each account, as weather data were matched to each account based on proximity of the account to a specific NOAA weather station.

[6] The day-of-load adjustment is calculated as the average difference between the baseline and the actual demand during the three hours of demand observed starting one hour prior to customer notification of the event. A day-of load adjustment is not appropriate for participants that received day-ahead notifications of events, as participants may modify behavior on the entire event day notification (e.g., by shifting load to pre- or post-event hours).

and December 26 included day-ahead notifications. Participants that received a day-ahead notification may have shifted load on event days (e.g., by halting or modifying operations in the hours leading up to the events). Since day-of adjustments are informed by observed demand in the hours leading up to an event, any verified impacts estimated using a baseline that has a day-of adjustment would be biased by behavior changes made by participants with day-ahead knowledge of an upcoming event. Guidehouse therefore did not include a day-of adjustment when calculating verified impacts.

3. Impact Findings

The discussion of program impacts is divided into the following sections:

1. **Demand Response Impacts – Overall.** This section provides the estimated *aggregate* impacts of curtailment during the two emergency demand response events called from June 1, 2022 through May 31, 2023, using Guidehouse's baseline testing approach. These events are listed in Table 3-1.
2. **Demand Response Impacts – Per Participant.** This section provides the estimated *per participant* impacts of curtailment during the two emergency demand response events called from June 1, 2022 through May 31, 2023, using Guidehouse's baseline testing approach. These events are listed in Table 3-1.
3. **Net-to-Gross.** This section outlines why the appropriate net-to-gross factor for this program should be 1.

Table 3-1. Events and Daily Peak Temperatures

Date	Season	Event Type	Enrollment Options Called	Event Time	Daily Minimum Temp. (°F)	Customers Called
12/24/2022	Winter	Emergency	PS-M, PS-G	4 am – 12 pm	-0.3	160
12/26/2022	Winter	Emergency	PS-M, PS-G	6 am – 10 am	7.7	160

Source: Guidehouse analysis of event settlement data and NOAA weather data

3.1 Demand Response Impacts – Overall

Guidehouse selected a baseline approach by testing a variety of potential methods and determining the best performing model in aggregate, as detailed in Appendix A.1 Estimating Verified Impacts Using a Baseline Testing Approach. Previously summarized in Section 2.4, the winning method was a 7-of-7 day CBL without day-of adjustment for the winter events. With this approach, the baseline is delivered by the average event window demand on the X days in which that demand was highest within a Y-day window preceding the event. These winning CBLs were used to estimate impacts for each account individually. Guidehouse aggregated the per-participant impacts for each event to estimate total load reduction by event.

Table 3-2 shows the estimated impacts by event and averaged across both events. For winter Emergency Events, the average reduction was 360.02 MW. A total of 160 customers were called across the events.

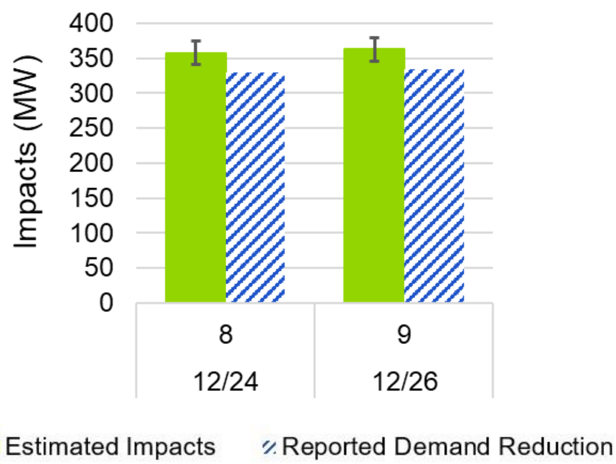
Table 3-2. Summary of Estimated Load Reduction by Event

Date	Accounts Called	Total Estimated Load Reduction (MW)	Margin of Error (± MW, 90% CI)	Relative Precision (± %)
12/24/2022	160	357.20	16.69	5%
12/26/2022	160	362.84	16.82	5%
Overall	**160**	**360.02**	**16.75**	**5%**

Source: Guidehouse analysis of participant AMI data and event settlement data

Figure 3-1 shows the average estimated event impacts compared to reported event impacts.[7] The reported event impacts presented in the blue bars represents the total reported load curtailment. The estimated impacts presented in the green bars represents the Guidehouse-estimated amount of curtailment that occurred during the event. In addition to showing the aggregate impact on each date, this plot shows the 90 percent confidence interval, represented by the whiskers straddling the top of the green columns.

Figure 3-1. Estimated Event Load Reduction vs. Reported Demand Reduction for Emergency Events



Source: Guidehouse analysis of participant AMI data and event settlement data

To provide further context into how accounts curtailed during events, Table 3-3 presents average estimated impacts per event, with results provided for accounts grouped by realization rate.[8] For Emergency Events, more than 90% of enrolled accounts had a realization rate of greater than 90%. Table 3-3 also provides context for how estimated impacts compare to reported impacts, the table lists average load reductions that were reported and verified by Guidehouse.

Table 3-3. Average Estimated Impacts per Event by Participation Category

Season	Event Type	Participation Category	Average Number of Accounts per Event*	Average Total Reported Curtailment (MW)	Average Total Estimated Impact (MW)	Realization Rate (Estimated / Reported)
Winter	Emergency	(< 33% of reported)	12	1.71	0.22	13%
		(34%-66% of reported)	4	2.34	1.03	44%
		(> 67% of reported)	143	328.03	358.78	109%
		Overall	**158**	**332.08**	**360.02**	**108%**

[7] The PowerShare program requires most customers to **curtail to** a pre-determined demand level, with some select customer types not required to curtail to a specific demand level due to the sensitive nature of their operations. Since PowerShare participants **curtail to** a certain demand level, rather than being required to **curtail by** a pre-determined amount, Guidehouse compared estimated load reductions to reported load reductions. This is a shift from evaluations provided for other jurisdictions, in which participants must **curtail by** a predetermined amount, in which Guidehouse compares estimated load reductions to contracted (curtail by) load reductions.

[8] Realization rate is calculated as estimated impact/reported curtailed.

*Guidehouse estimated Emergency Event impacts for 158 of 160 accounts called, as two accounts were missing AMI data on the Emergency Event days.

Source: Guidehouse analysis of participant AMI data and event settlement data

3.2 Demand Response Impacts – Per Participant

In the previous section, Guidehouse aggregated the per-participant impacts for each event to provide a total estimated load reduction by event. This section provides the estimated per-participant impacts from the two emergency demand response events called during 2022-2023.

Table 3-4 shows per-participant estimated impacts by event and averaged across events. Similar to total estimated load reductions summarized in the previous section, estimated per participant load impacts for winter Emergency Events exceeded reported load impacts. On average across the two Emergency Events, Guidehouse estimated per-participant load reduction of 2.28 MW, which exceeded the average reported per-participant load reduction of 2.10 MW.

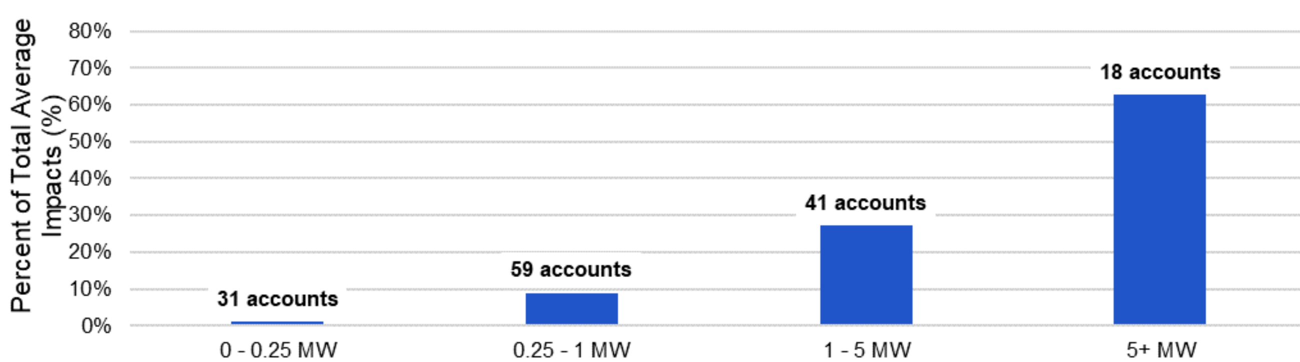
Table 3-4. Summary of Estimated Load Reduction by Event – Per Participant

Date*	Accounts Called	Per Participant Load Reduction (MW)	Margin of Error (± MW, 90% CI)	Relative Precision (± %)
12/24/2022	160	2.26	0.11	5%
12/26/2022	160	2.30	0.11	5%
Overall	**160**	**2.28**	**0.11**	**5%**

Source: Guidehouse analysis of participant AMI data and event settlement data

Figure 3-2 shows the distribution of average impacts by account across Emergency Events called in the winter. Nine accounts with zero or negative impacts are not shown. A small number of called accounts (18 accounts in total) provided more than 60 percent of the curtailed load across the two events, with these accounts having large estimated absolute load reductions amounting to greater than 5 MW. An additional 30 percent of load shed during the two Emergency Events was driven by 41 additional accounts that were estimated to have shed between 1 and 5 MW during the two called events. A large number of accounts (90 accounts in total) contributed to the remaining 10 percent of load shed during events, with these accounts being estimated to have shed less than 1 MW of load during the called events.

Figure 3-2. Distribution of Average Load Reduction by Account



Average impact per event (MW) per account is calculated using all events a participant was called for. As a result, the total average impact represents the estimated impact if all accounts were called for an event. A total of 9 accounts are not presented for the winter, as impacts for these accounts were zero or negative.

Source: Guidehouse analysis of participant AMI data and event settlement data.

Table 3-5 shows per participant average load reductions reported (per DEC settlement procedure), and verified (through this evaluation).

Table 3-5. Average Verified and Reported Load Reductions per Participant

Load Reduction Category	Average Estimated Per-Participant Load Reduction (MW)
Reported (settlement)	2.10
Verified (evaluation)*	2.28
Realization Rate (Verified / Reported)	**108%**

*The verified per-participant load reduction is calculated as the weighted average per-participant load reduction based on the number of participants in each event (i.e., impacts from events with more participants contributed greater weight to the average estimated per-participant load reduction).

Source: Guidehouse analysis of participant AMI data and event settlement data.

3.3 Net-to-Gross

Evaluations of demand-side management programs typically estimate both net and gross savings, and often present a net-to-gross (NTG) ratio based on the evaluated percentage of demand reductions that may be ascribed either to free ridership (which decreases the NTG ratio) or to program spillover (which increases it). Free ridership is typically defined as the percentage of savings that would have occurred absent the presence of the program. Spillover is typically defined as incremental savings actions undertaken by a program's participants not directly claimed by the program.

Since demand reductions are estimated in contrast to an estimated baseline that captures expected participant behavior absent an event, Guidehouse can confidently state that the free ridership is zero. Absent the program, none of the observed demand reductions would have taken place. There is no reason to think non-participants would curtail in absence of the incentives and structure of the program and so spillover is zero. With both freeridership and spillover at zero, the NTG ratio is 1.0 and all savings presented in this report should be considered net.

4. Findings, Conclusions, and Recommendations

This section includes a summary of the key findings presented throughout this report, along with some recommendations for DEC to consider.

4.1 Findings

The key findings of Guidehouse's impact evaluation of the DEC PowerShare program for this evaluation period are:

- **Guidehouse estimated an average total curtailment of 360.02 MW across the two Emergency Events called in 2022-2023, resulting in a 108 percent realization rate.** The two Emergency Events, which were called for customers enrolled in the Mandatory Curtailment and Generator Curtailment program options, yielded estimated total load shed of 357 MW on December 24 and 363 MW on December 26. This estimated load curtailment exceeded reported load curtailment received from Duke Energy, with a realization rate of 108 percent when comparing estimated to reported load curtailment across the two events.

- **In aggregate, Emergency Events result in reliable and effective load curtailment during the event hours.** When assessing event participation, Guidehouse examined aggregate load shapes and realization rates for load curtailment estimated for each customer for each event. Inspection of aggregate load shapes revealed a program-wide response to the Emergency Events, with a marked reduction in load throughout the duration of the two events. In addition, approximately 90 percent of customers had a realization rate (estimated impacts/reported imacts) greater than 67 percent.

- **A limited number of customer accounts had little to no demand response to the Emergency Events.** When estimating load curtailment for the two Emergency Events, Guidehouse observed that realization rates for a subset of customers (12 accounts of the 160 accounts called) were less than 33 percent, indicating a large gap between anticipated curtailment and estimated curtailment. Consistent with this finding, Guidehouse's inspection of aggregate load shapes for these customer accounts revealed a weak response to the called events, with almost no change in observed load during the event hours.

4.2 Recommendations

Based on the findings above, Guidehouse developed the following recommendations:

- **Continue to call Emergency Events during times in which system capacity is constrained.** Based on estimated reductions in load across the two Emergency Events, Guidehouse estimates that across the majority of enrolled customers, Emergency Events are capable of encouraging load shed. As such, Guidehouse recommends that Duke Energy continue to call Emergency Events as a means of shedding load during times of system capacity constraints.

- **Consider investigating what drove lower event participation for a subset of accounts.** A limited number of accounts exhibited little to no response to the Emergency Events. Since the two called Emergency Events overlapped with December holiday season, an initial hypothesis of what drove a weak response for a subset of accounts was that the customers' load was already at or below their contract demand (i.e., the demand they must maintain during events). Investigation of aggregate load shapes against contract demand did not support this hypothesis, with average observed load leading up to and during the event exceeding contract demand amounts. Gathering an understanding of what drove lower participation amongst a subset of accounts will give Duke Energy an indication of what, if any, program components may be improved to encourage participation during Emergency Events.

5. Summary Form

PowerShare®

2022-2023

Completed EMV Fact Sheet

Description of Program

The PowerShare program is a demand response (DR) program offered to commercial and industrial (C&I) customers that is part of the portfolio of demand side management and energy efficiency (DSM/EE) programs offered by Duke Energy. PowerShare offers participating customers a financial incentive to reduce their electricity consumption when called upon by Duke Energy.

The DEC program offers customers three participation options to choose from:

- **Mandatory Curtailment:** Participants enrolled in the Mandatory Curtailment Option are required to reduce and maintain load during each Mandatory Curtailment Period to the level specified in their PowerShare contract.
- **Voluntary Curtailment:** Participants enrolled in the Voluntary Curtailment Option can take part in Voluntary Curtailment Periods on a per-event basis. If a participant elects to participate in an event, they should reduce and maintain their load to a pre-specified level.
- **Generator Curtailment:** Participants enrolled in the Generator Curtailment Option are required to transfer load from their Duke Energy power source to a private generation source during each Generator Curtailment Period.

Date:	2024-01-04
Region:	DEC
Evaluation Period	June 1, 2022 – May 31, 2023
Average DR Event Program Impact (MW)	
Load Reduction Impacts (Program total, averaged across Emergency Events)	Winter: 360.02 MW
Net-to-Gross Ratio	1.0

Evaluation Methods

Accounts enrolled in the Mandatory Curtailment and Generator Curtailment program options of the PowerShare program were called to participate in two Emergency Events called by Duke Energy, one on December 24, 2022 and one on December 26, 2022. Guidehouse estimated demand response impacts of these two events using a baseline testing approach applied to called accounts' advanced metering infrastructure interval consumption data collected during the 2022-2023 evaluation period spanning June 1, 2022 through May 31, 2023.

Evaluation Findings

- **Guidehouse estimated an average total curtailment of 360.02 MW across the two Emergency Events called in 2022-2023, resulting in a 108 percent realization rate.** The two Emergency Events, which were called for customers enrolled in the Mandatory Curtailment and Generator Curtailment program options, yielded estimated total load shed of 357 MW on December 24 and 363 MW on December 26. This estimated load curtailment exceeded reported load curtailment received from Duke Energy, with a realization rate of 108 percent when comparing estimated to reported load curtailment across the two events.
- **In aggregate, Emergency Events result in reliable and effective load curtailment during the event hours.** When assessing event participation, Guidehouse examined aggregate load shapes and realization rates for load curtailment estimated for each customer for each event. Inspection of aggregate load shapes revealed a program-wide response to the Emergency Events, with a marked reduction in load throughout the duration of the two events. In addition, approximately 90 percent of customers had a realization rate (estimated impacts/reported imacts) greater than 67 percent.
- **A limited number of customer accounts had little to no demand response to the Emergency Events.** When estimating load curtailment for the two Emergency Events, Guidehouse observed that realization rates for a subset of customers (12 accounts of the 160 accounts called) were less than 33 percent, indicating a large gap between anticipated curtailment and estimated curtailment. Consistent with this finding, Guidehouse's inspection of aggregate load shapes for these customer accounts revealed a weak response to the called events, with almost no change in observed load during the event hours.

Appendix A. Detailed Impact Evaluation Methodology

This section details the methods used for estimating impacts using the baseline testing approach, as well as the MISO baseline method.

A.1 Estimating Verified Impacts Using a Baseline Testing Approach

A.1.1 Testing of Candidate Baseline Methods

Guidehouse performed the following steps to test candidate baselines and select the approach to be used for verifying DR impacts:

1. **Identify Test Days.** Guidehouse identified three test days for each season (summer and winter) and participant. Test days are non-holiday, non-event weekdays with a temperature profile as similar as possible to that of the actual event days. Guidehouse selected test days as the three non-event, non-holiday weekdays with the highest average temperature for the summer season, and the three coldest such days for the winter season.

2. **Estimate Baselines**. Based on the test days selected, Guidehouse estimated the demand during expected periods of high demand in each season (1 p.m. to 7 p.m. in June - October and May, 6 a.m. to 11 a.m. and/or 5 p.m. to 10 p.m. in November - April) on those test days using all candidate approaches – 23 CBLs and seven regression models.

3. **Quantify Accuracy and Select Approaches.** Each customer's baseline generated by each approach tested was assigned a metric of accuracy as the root mean squared error between predicted and actual demand. These metrics were aggregated across customers[9] by approach to determine the overall accuracy rank (for the entire program) of each approach in each season. Guidehouse selected the most accurate approach in aggregate to calculate verified impacts in each season. Emergency Events called on December 24 and December 26 included day-ahead notifications. Participants that received a day-ahead notification may have shifted load on event days (e.g., by halting or modifying operations in the hours leading up to the events). Since day-of adjustments are informed by observed demand in the hours leading up to an event, any verified impacts estimated using a baseline that has a day-of adjustment would be biased by behavior changes made by participants with day-ahead knowledge of an upcoming event. Guidehouse therefore did not include a day-of adjustment when calculating verified impacts.

The day-of load adjustment is calculated as the average difference between the baseline and the actual demand during the three hours leading up to the hour prior to customer notification of

[9] Aggregation of metrics will explicitly account for customer loads to ensure that the baseline selected is the one that is most accurate for the program overall.

the event. For testing the adjustments, Guidehouse used an assumed notification time of 1 hour prior to each “event.”

The types of baselines tested by Guidehouse fall into two broad categories: CBLs and regression-based baselines. These are described in greater detail below. Note that each approach listed below was tested twice: once with a symmetric and additive day-of load adjustment, and once with no day-of load adjustment (i.e., assuming that notification was day-ahead).

A.1.2 CBL Specifications

Guidehouse tested the 23 CBLs listed in Table A-1. These included CBLs split across two categories:

- **X-of-Y day CBLs**. In this case the baseline is delivered by the average event window demand on the X days in which that demand was highest within a Y-day window preceding the event; and,
- **X-of-Y days of the same day-of-week CBLs.** In this case, the baseline delivered by the average event window demand on the X number of prior days in which demand was highest within the Y number of days that fall on the same day of the week as the event.

Only non-event days may qualify for inclusion in the baseline. A day may qualify for inclusion in the baseline if and only if it is a non-holiday, non-event weekday.

Qualifying non-event days are eligible for inclusion in the look-back window (the period of Y days) in the baseline only if the participant’s average demand during the event period on that day is 50 percent or more of the average demand across all Y days.

Days that fail to meet the eligibility criterion (i.e., days where the average demand during the event window are less than half of the average demand in that window across the Y days of the look-back period) are replaced by next most proximate preceding qualifying and eligible day. If there are not three qualifying days out of the ten non-excluded days preceding the event, the algorithm reverts to using the three most-immediate non-excluded days prior to the event.

Table A-1. CBLs to be Tested

CBL Number	CBL
1	2-of-2
2	2-of-3
3	3-of-3
4	2-of-4
5	3-of-4
6	4-of-4
7	3-of-5
8	4-of-5
9	5-of-5
10	3-of-6
11	4-of-6
12	5-of-6
13	6-of-6
14	4-of-7
15	5-of-7
16	6-of-7
17	7-of-7
18	2-of-2 of same day-of-week
19	2-of-3 of same day-of-week
20	3-of-3 of same day-of-week
21	2-of-4 of same day-of-week
22	3-of-4 of same day-of-week
23	4-of-4 of same day-of-week

Source: Guidehouse

A.1.3 Regression Based Baselines

All regression specifications discussed below are variants of a core model that accounts for a base set of demand patterns. The base, or core, model specification of the regression model is presented below in Equation A-1.

Equation A-1. Core Regression Model

$$y_t = \sum_{i=1}^{48} \beta_{1,i} hhour_{t,i} + \sum_{i=1}^{48} \beta_{2,i} qhour_{t,i} DHH_t + \sum_{d=1}^{D} \gamma_d C_{t,d} + errors$$

Where:

y_t = The average demand (kW) observed at the given meter in the half hour of sample *t*.

$hhour_{t,i}$ = A set of 48 dummy variables, one for each half-hour of the day. The given dummy takes a value of 1 when the half-hour of sample is the i-th half-hour of that day. For example: if half-hour t is between midnight and 12:30 AM, $hhour_{t,i=1}$ is equal to one and zero otherwise.

DHH_t = The cooling (in summer) or heating (in winter) degree half-hours (base 65F) in half-hour of sample t. This variable accounts for that the heating or cooling demand influences energy consumption.

$C_{t,d}$ = A set of D dummy variables identifying each half-hour in which a curtailment event took place. Each event is given its own index – for example if there are two events of one hour each, half-hours across all events are indexed from 1 to 4. These variables capture the impact of curtailment.

Guidehouse also tested specifications that include the following additional variables.

$EMA6dh_t$ = An exponential moving average of DHH_t observed in the six-hour period leading up to, and including, hour *t*. This variable captures any effect of temperature in previous hours on the current hours demand (e.g., if it has been hot for a while, cooling demand may be higher)

$EMA24dh_t$ = Identical to $EMA6dh_t$, except for 24, instead of, six hours. This variable captures any effects of temperature in previous hours on the current hours demand (e.g., if it has been hot for a while, cooling demand may be higher)

hbu_t or cbu_t = "Heat index build-up" (for summer) or "cold build up" (for winter) observed in half-hour of sample t. This variable captures the effect of heat or cold "build up" in previous hours on the current hours demand (e.g., if it has been hot and humid for a while, cooling demand may be higher). This is a 72-hour geometrically decaying average of the NOAA-defined heat index[10] (for summer) and of heating degree half-hours (for winter). It is calculated in the following manner (note that t in this equation refers to hour). It is calculated in the following manner:

$$hbu = \frac{\sum_{h=1}^{72} 0.96^h \cdot heatindex_{t-h}}{1000} \quad \text{or} \quad cbu = \frac{\sum_{h=1}^{72} 0.96^h \cdot HDHH_{t-h}}{1000}$$

Note in this case that the *t* subscript denotes hourly intervals.

In total, Guidehouse tested seven different regression specifications (with and without day-of adjustment): the core model and six models consisting of the core model with additional variables as listed in Table A-2. The HBU variable was used for the summer season and the CBU variable was used for the winter season.

[10] National Oceanic and Atmospheric Administration, National Weather Service – Weather Prediction Center, *The Heat Index Equation*, accessed February 2018. **http://www.wpc.ncep.noaa.gov/html/heatindex_equation.shtml**. There are additional adjustments that are applied within certain temperature and humidity ranges.

Table A-2. Additional Variables Included in Regression Specifications Tested

Model	Var1	Var2	Var3
1	ema6dh		
2	ema24dh		
3	hbu or cbu		
4	hbu or cbu	ema6dh	
5	hbu or cbu	ema24dh	
6	hbu or cbu	ema6dh	ema24dh

Source: Guidehouse

A.1.4 Estimating Verified Impacts

Guidehouse estimated baseline demand using the best-performing baseline approach given when event notification took place (i.e., if notification is day-ahead, then no day-of adjustment approach was used for evaluation). Guidehouse then estimated verified impacts by comparing observed in-event demand to estimated baseline demand. Guidehouse estimated verified impacts for each event in the evaluation period, as well as the average across all events, for each customer and for all customers in aggregate (i.e., the program total).

Negative DR impacts (where baseline demand is lower than actual demand) were not "zeroed out" for each participant. This is to account and compensate for the random variation that will sometimes lead baselines to be too high (overestimating impacts), and other times to be too low (underestimating impacts). However, consistent with Guidehouse's evaluation of similar Duke Energy programs, negative impacts were not included when reporting aggregate (program total) impacts.

Appendix B. Impact Output Summary Spreadsheet

Please see the accompanying spreadsheet for Appendix B.