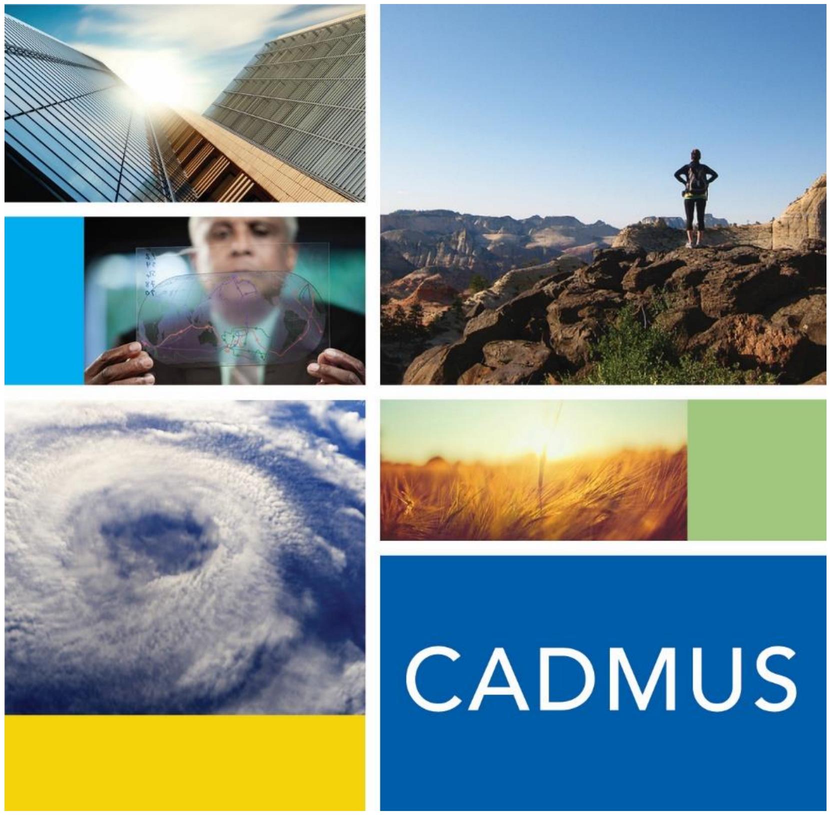

Demand Response Program Annual Evaluation

Phase III of Act 129
Program Year 9
(June 1, 2017—May 31, 2018)
for Pennsylvania Act 129 of 2008
Energy Efficiency and Conservation Plan

Prepared by Cadmus for

PPL Electric Utilities

January 15, 2018

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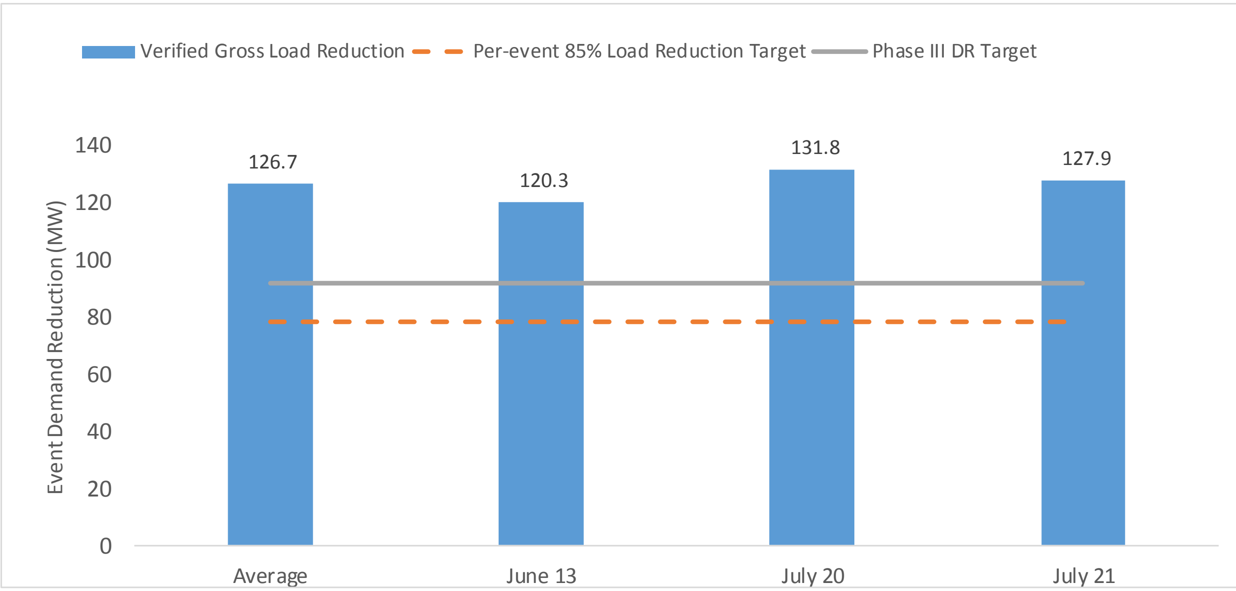
1 Demand Response Program

1.1 Executive Summary

PPL Electric Utilities' Act 129 Demand Response Program operated effectively in PY9 and PPL Electric Utilities is on track to meet its Phase III Act 129 Demand Reduction Compliance target. Figure 1 summarizes the evaluation impact findings for PY9.

Figure 1. Gross Verified Savings in Comparison to Act 129 Targets



Note: The load impacts reported in this figure are based on Cadmus analysis of participant AMI consumption data and have been grossed up to reflect transmission and distribution losses.

In PY9, verified peak load reductions were 126.7 MW (average over the three demand response events) which exceeds the Phase III compliance target of 92 MW (average over all Phase III demand response events). In addition, PPL Electric Utilities met its per-event compliance target of at least 78.2 MW (85% of the total compliance target) in each demand response event.

1.2 Background

During Phase III, PPL Electric Utilities operated the Demand Response Program for commercial and industrial (C&I) customers and for government, nonprofit, and education (GNE) customers. Participating customers entered into contracts with the program's implementation conservation services provider (ICSP) to voluntarily reduce electricity demand during Act 129 demand response events. A total of 93 PPL Electric Utilities customers participated in Act 129 demand response events during program year 9 (PY9).

CPower was the program's ICSP. PPL Electric Utilities managed the ICSP and provided overall strategic direction for the program. The ICSP enrolled and contracted with customers, initiated events during the summer (June–September 2017) of PY9, and made performance-based payments to participants.

In PY9, PPL Electric Utilities initiated three load curtailment events, which occurred on June 13, July 20, and July 21 of 2017. Each event occurred on non-holiday, weekdays between 2:00 p.m. and 6:00 p.m. PPL Electric Utilities initiated each event in accordance with Act 129 demand response rules, which require a 4-hour event on the following day when at least one hour of the PJM RTO day-ahead forecast exceeds 96% of the PJM's forecast of summer peak demand. Per Act 129 demand response rules, there can be a maximum of six events per program year, and there were three events in PY9.

The ICSP notified participants between 10:00 a.m. and 6:00 p.m. on the day before the event, and most participants received notification in the morning or early afternoon. Before the start of each event, the ICSP received a commitment from these notified customers to participate in the event for specific hours. To enroll in an event, participants selected specific hours for enrollment on the ICSP's online platform, which served as the primary enrollment and feedback channel for the program. Participants had the option of participating for all or a subset of event hours. Across all events and customers, only four times did a customer participate for a subset of hours.

To comply with the PaPUC's Act 129 Phase III demand response compliance targets, PPL Electric Utilities' Demand Response Program must reduce its system load by an average of 92 MW (measured at the generator level) over all demand response events during the last four years of Phase III (PY9–PY12). [1] In addition, PPL Electric Utilities is required to achieve a minimum of 85% of the 92 MW compliance target or 78.2 MW during each event.

Compliance targets for demand response programs were established at the generator level, which means the load reductions measured at the customer meter must be increased to reflect transmission and distribution losses (line losses). The peak demand impact estimates presented in this report have been adjusted for these line losses. PPL Electric Utilities uses the following line loss percentages/multipliers by sector.

- Small C&I = [8.75% or 1.0875]
- Large C&I = [4.2% or 1.0420]

1.3 Progress Toward Phase III Projected Savings

PPL Electric Utilities designed the Demand Response Program for approximately 115 MW, to exceed its 92 MW Act 129 demand response compliance target to account for various operational and evaluation uncertainties. In PY9, PPL Electric Utilities achieved verified peak demand reductions that averaged 126.7 MW over all event hours, which are 11.7 MW (~10%) greater than estimated in the EE&C Plan and approximately 38% greater than the 92 MW target for Phase III

Table 1 shows the program's verified gross peak demand reductions and progress toward its Phase III totals, as filed in the EE&C plan.

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[1] Program objectives are stipulated on PPL Electric Utilities' revised EE&C Plan (Docket No. M-2015-2515642) filed with the Pennsylvania PUC on June 6, 2017.

Table 1. PY9 Demand Response Program Estimated and Verified Savings

Event	PY9 Only			Phase III: PY8–PY12 [1]		
	EE&C Plan Estimate [2] (MW)	Verified [3] (MW)	Percentage of Estimated	EE&C Plan Estimate [2] (MW)	Verified (MW)	Percentage of Estimated
Demand response capacity	115	126.7	110.2%	115	126.7	110.2%

[1] All demand reductions are averages across all events. The planned reductions are not summed across years, since the sum of demand reductions across years is not a meaningful concept. There were no demand response events in PY8. The first demand response events occurred in PY9.

[2] Planned savings are based on PPL Electric Utilities' revised EE&C plan (Docket No. 2015-2515642) filed with the Pennsylvania PUC on June 6, 2017. Estimated demand reduction is shown per event hour.

[3] Verified savings are the average demand response savings per event during the June 13, July 20, and July 21 Act 129 events.

1.4 Participation and Reported Savings by Customer Segment

1.4.1 Definition of a Participant

A participant in PPL Electric Utilities' Demand Response Program in PY9 is defined as customer (unique account number) that participated in at least one of PPL Electric Utilities' Act 129 demand response events.

1.4.2 Program Participation and Reported Impacts

Table 2 presents the participation counts, reported demand reduction, and incentive payments for the Demand Response Program in PY9 by customer segment and Act 129 event.

The program reported demand savings of approximately 101 MW on June 13, 2017, 125 MW on July 20, 2017, and 121 MW on July 21, 2017. Large C&I customers accounted for 96% to nearly 100% of the reported demand savings for these events.

Table 2. PY9 Demand Response Program Participation and Reported Impacts [1]

Parameter	Small C&I (Non-GNE)	Large C&I (Non-GNE)	GNE	Total [2]
PYTD # Participants	60	23	10	**93**
June 13, 2017 Reported MW	(0.74)	101.27	0.34	**100.87**
July 20, 2017 Reported MW	0.11	121.23	3.92	**125.26**
July 21, 2017 Reported MW	-	116.69	4.11	**120.80**
Total Average Reported MW	**(0.31)**	**113.06**	**2.79**	**115.6**
PY9 Incentives ($1000)	$0.35	$956	$23	**$980**

[1] The load impacts reported in this table have been grossed up to reflect transmission and distribution losses.

[2] Total may not equal total of row due to rounding.

1.5 Gross Impact Evaluation

The impact evaluation sampling strategy is summarized in Table 3. Cadmus analyzed consumption data to estimate Act 129 load impacts for the population of participants. There was no sampling. The number and composition of participants varied between events, because the ICSP called upon different sets of customers for each event.

Table 3. PY9 Demand Response Program Gross Impact Sample Design

Stratum	Event	Population Size	Assumed Proportion or Cv in Sample Design	Achieved Sample Size	PYRTD MW	Impact Evaluation Activity
Small C&I	June 13, 2017	59	N/A (Census)	59	(0.74)	Individual customer impact analysis
	July 20, 2017	1	N/A (Census)	1	0.11	Individual customer impact analysis
	July 21, 2017	0	N/A (Census)	0	-	Individual customer impact analysis
Large C&I	June 13, 2017	22	N/A (Census)	22	101.27	Individual customer impact analysis
	July 20, 2017	18	N/A (Census)	18	121.23	Individual customer impact analysis
	July 21, 2017	18	N/A (Census)	18	116.69	Individual customer impact analysis
GNE	June 13, 2017	9	N/A (Census)	9	0.34	Individual customer impact analysis
	July 20, 2017	10	N/A (Census)	10	3.92	Individual customer impact analysis
	July 21, 2017	10	N/A (Census)	10	4.11	Individual customer impact analysis
Program Total	June 13, 2017	90	N/A (Census)	90	100.87	Individual customer impact analysis
	July 20, 2017	29	N/A (Census)	29	125.26	Individual customer impact analysis
	July 21, 2017	28	N/A (Census)	28	120.80	Individual customer impact analysis

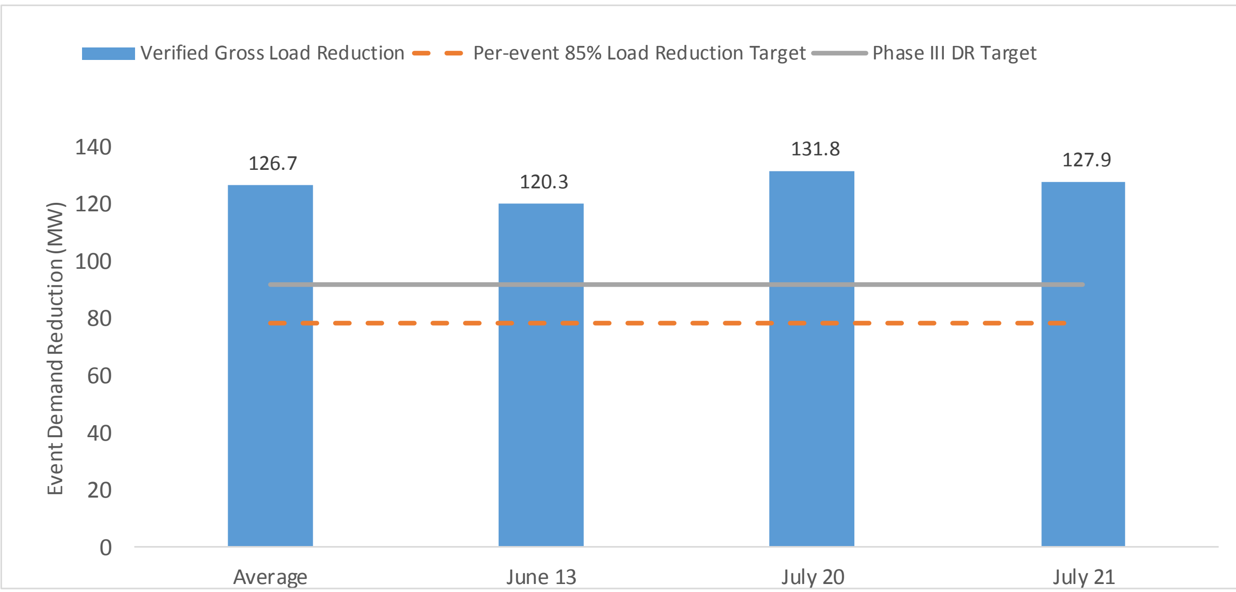
Note: The load impacts reported in this table have been grossed up to reflect transmission and distribution losses.

Before the start of PY9, Cadmus collected 15-minute advanced metering infrastructure (AMI) interval consumption data from 2016 for recruited facilities and conducted an individual facility analysis to identify the most accurate baseline calculation method for Cadmus' determination of verified peak reductions for each participant. Cadmus evaluated the predictive accuracy of a range of day-matching methods such as the "three previous non-holiday, non-event weekdays" or "seven days of previous 10 non-holiday, non-event weekdays with the highest loads" and a variety of regression model specifications. Cadmus then used the most accurate baseline model to determine the verified peak load reductions during three Act 129 demand response events in summer 2017. Cadmus determined the verified peak load reductions for each customer during each event hour and the average load reduction for each event. Additional details about the evaluation methodology are in *Appendix A*.

The research activities in PY9 were consistent with the evaluation plan except that Cadmus determined that for small C&I or GNE facilities day-matching produced event hour consumption baselines that were too low. Day-matching did not account for the positive correlation between Act 129 event days and facility electricity demand for air conditioning. Instead of day-matching, Cadmus used regression to estimate baselines for all GNE and small C&I facilities.

Table 4 shows that in PY9 the Demand Response Program verified average demand reduction is 126.7 MW. This yields a realization rate of 110% relative to the reported (*ex ante*) load reduction. The verified average demand savings exceeded by 34.7 MW PPL Electric's Act 129 goal for Phase III. As Figure 2 shows, PPL Electric Utilities is on track to meet the Phase III goal of an average of 92 MW per event hour.

Figure 2. Gross Verified Savings in Comparison to Act 129 Targets



Note: The load impacts reported in this figure are based on Cadmus analysis of participant AMI consumption data and have been grossed up to reflect transmission and distribution losses.

PPL Electric Utilities achieved verified demand savings of 120.3 MW on June 13, 2017, 131.8 MW on July 20, 2017, and 127.9 MW on July 21, 2017, yielding realization rates of, respectively, 119%, 105%, and 106%.

The following factors may have led to differences between the reported and verified savings and realization rates that deviated from 100%:

- **Different treatment of estimated readings**. PPL Electric Utilities estimated about 2% of all hourly interval readings for participant facilities between April 1, 2017, and July 21, 2017. Cadmus replaced these estimated readings with missing values and did not include them in the analysis sample. It was not possible to estimate demand savings for one small C&I facility because all of its kWh readings for event hours were estimated.
- **Allowance of event notification days in basis window.** Cadmus excluded event notification days from consideration for the basis window when calculating customer baselines. This exclusion was justified because Cadmus' analysis of load impacts on notification days showed that many

customers increased or decreased their loads in response to event notifications. (See *Appendix A*.) The ICSP did not exclude event notification days when calculating customer baselines.

- **Different methods for calculating customer baselines.** To the extent possible, the ICSP attempted to align its baseline calculation method with Cadmus' method. However, for all small C&I and GNE facilities and approximately half of large C&I facilities, Cadmus employed regression analysis to calculate the baseline while the ICSP employed day-matching. The ICSP reasoned that day-matching was easier for participants to understand than regression; Cadmus believed that regression yielded more accurate predictions of customer consumption.

The large C&I sector produced most of the program's demand savings. Large C&I participants provided average demand savings per hour of 113.9 MW on June 13, 2017, 127.0 MW on July 20, 2017, and 123.0 MW on July 21, 2017, or about 95% of the total verified savings.

Table 4. PY9 Demand Response Program Gross Impact Results for Demand

Stratum	Event	PYRTD MW	Demand Realization Rate	PYVTD MW [1]	Sample C_v or Error Ratio	Relative Precision at 90% C.L. [2]
Small C&I	June 13, 2017	(0.74)	-404%	2.97	NA	17%
	July 20, 2017	0.11	162%	0.17	NA	13%
	July 21, 2017	-	0%	-	NA	NA
Large C&I	June 13, 2017	101.27	112%	113.86	NA	6%
	July 20, 2017	121.23	105%	126.99	NA	5%
	July 21, 2017	116.69	105%	123.01	NA	5%
GNE	June 13, 2017	0.34	1022%	3.46	NA	16%
	July 20, 2017	3.92	119%	4.65	NA	18%
	July 21, 2017	4.11	120%	4.92	NA	17%
Event	**June 13, 2017**	**100.87**	**119%**	**120.29**	**NA**	6%
	July 20, 2017	**125.26**	**105%**	**131.81**	**NA**	5%
	July 21, 2017	**120.80**	**106%**	**127.93**	**NA**	5%
Average		**115.64**	**110%**	**126.68**	**NA**	3%

[1] Based on Cadmus analysis of participant AMI consumption data. MW were grossed up to reflect transmission and distribution losses.
[2] Precision accounts for covariances of savings across hours of each event, but not for covariances of savings between events.

1.6 Verified Savings Estimates

In Table 5, the realization rates determined by Cadmus are applied to the reported demand savings estimates to calculate the verified savings estimates for the Demand Response Program in PY9. In future years, these and future estimates of verified demand reductions and will be averaged to calculate the P3TD program impacts.

Table 5. PYTD and P3TD Demand Savings Summary

Savings Type	Demand (MW) [1] [2]
PYRTD	115.64
PYVTD Gross	126.68
PYVTD Net [3]	-
P3RTD	115.64
P3VTD Gross	126.68
P3VTD Net [3]	-

[1] Savings are presented as the average of the total demand response reductions per event across the June 13, July 20, and July 21 Act 129 events.
[2] Total may not match due to rounding.
[3] There are no net savings because neither free riders nor spillover apply to this program. C&I and GNE participants are not expected to curtail their loads without notification of PPL Electric system peaks and without compensation.

1.7 Process Evaluation

1.7.1 Research Objectives

The process evaluation assessed program implementation and customer satisfaction. The main research objectives focused on these areas:

- Customer recruitment and motivation
- Customer satisfaction and response to event notification
- Customer response to payment
- Program design and implementation
- Customer perspective about program benefits and costs
- Customer action to reduce loads

1.7.2 Evaluation Activities

Table 6 lists the PY9 process evaluation activities for the Demand Response Program.

Table 6. PY9 Demand Response Program Process Evaluation Activities

Activity	Achieved Target
PPL Electric Utilities and ICSP program manager interview	2
Telephone participant interviews	10
Review program logic model	N/A

Considering the smaller than expected participant sample frame, 26 unique companies managed the 93 participating facilities, Cadmus altered the target number of completed participant interviews from 70 to 10 and opted for telephone surveys instead of a mix of online and telephone surveys. Furthermore, because of the small sample size, Cadmus could not estimate population parameters with 90% confidence and +/- 10% precision.

The five largest participating companies in the Demand Response Program represent ~75% of the total enrolled peak reductions (MW). Despite multiple attempts to contact high priority participants (ranked by enrolled MW load reduction) via email and phone calls, Cadmus completed interviews with 3 of the top 10 participants. Although Cadmus met the evaluation target of 10 participant interviews, none of the top five participants agreed to an interview, which limited the representative enrolled MW of interview respondents to 12.4% of the total enrolled MW in the program. Therefore, the responses are representative of small (by MW) participants.

Table 7 lists the process evaluation sampling strategy. Additional details about sampling methodology are included in *Appendix A*.

Table 7. Process Evaluation Sampling Strategy

Stratum	Stratum Boundaries	Mode	Population Size	Assumed Proportion or Cv in Sample Design	Target Sample Size	Achieved Sample Size	Number of Records Selected for Sample Frame [1]	Percent of Sample Frame Contacted to Achieve Sample [2]
PPL Electric Utilities Program and ICSP Staff	Staff	Telephone in-depth Interview	2	N/A	2	2	N/A	100%
Participant Surveys	Participating Companies [3]	Telephone in-depth interviews	26	N/A	10	10	26	100%
Program Total								

[1] Sample frame is a list of participants with contact information who have a chance to complete the survey. The final sample frame includes unique records in the PPL Electric Utilities database.
[2] Percent contacted means the percentage of the sample frame called to complete surveys.
[3] 26 unique companies managed the 93 participating facilities. See *Appendix A, Process Evaluation*, for additional discussion.

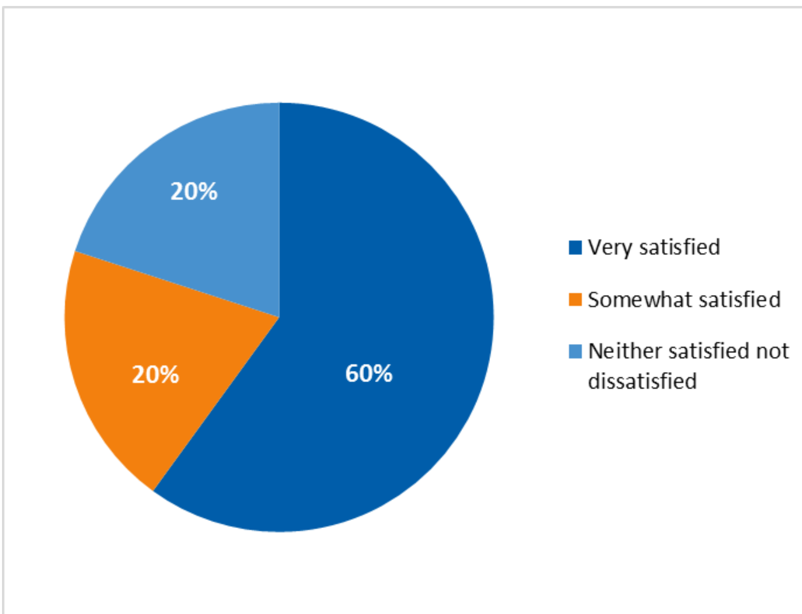
1.7.3 Summary of Process Evaluation Findings

Overall, program managers and participants said the program is working well and as intended.[2] The program met the Act 129 demand reduction target and most customers are satisfied with the program, plan on participating in 2018, and said the program was worthwhile from a business standpoint. PPL Electric's and the ICSP's substantial upfront investment in a detailed operations manual and program design likely resulted in participant satisfaction with the program overall and with key design elements. The program did encounter minor issues with customer enrollment and performance during the first event. These issues were properly addressed for the second and third event. In interviews with 10 program participants, representing roughly 12% of the total enrolled MW load reduction, respondents said payment timing is the primary challenge facing the program.

1.7.3.1 Participant Satisfaction

Overall, participants were satisfied with PPL Electric Utilities' Demand Response Program. Out of 10 interview respondents, six said they were *very satisfied* with the program, and two said they were *somewhat satisfied* (Figure 3). None of the participants Cadmus interviewed said they were dissatisfied with the program overall.

Figure 3. Overall Program Experience



Source: Interview question D1, "Thinking about your overall experience with the PPL Electric Utilities Demand Response Program, how would you rate your satisfaction" (n=10)

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2 As previously noted, the five largest participating companies in the Demand Response Program represent ~75% of the total enrolled peak reductions (MW). However, none of the top 5 participating companies provided input to the process evaluation. Therefore, the findings are representative of the smaller participating companies that comprise ~12% of the Demand Response Program's MWs.

1.7.3.2 Program Benefits and Costs

Cadmus asked interview respondents whether it was worthwhile from a business standpoint to shut down or curtail operations in order to participate in the program. Eight of 10 respondents said the program benefits outweighed the costs and the program was worthwhile. The other two respondents had reduced their peak load by shifting to backup generators and had not yet compared the generator fuel costs to the expected incentive. One of these respondents said the benefits of PPL Electric Utilities' Demand Response Program were not good enough and compared poorly to PJM's program, which offered higher incentives.

Most respondents said the expected incentive amount was adequate. The ICSP waits for the annual evaluation to determine verified peak reductions before processing incentive payments. Since the program ICSP had not yet paid the incentive as of December 2017, two participants were anxious about recouping incurred operational costs. These two respondents said they were concerned by the delay in incentive payments and viewed the payment timing as inadequate compared to PJM's quarterly payment structure. The other respondents did not identify payment timing as a concern.

1.7.3.3 Design and Implementation

All 10 respondents said that the timing of event notifications was adequate for them to prepare, and 3 respondents identified the 24-hour event notification as the primary strength of the program. Also, respondents did not view the duration or frequency of events as major challenges, with all 10 reporting that the duration and frequency of the events did not affect their ability to participate.

Two respondents said they found the online platform difficult to use for the first event. Neither fully understood how to enroll for all hours of the event and how to interpret the performance reports on the online platform, and one did not fully understand how the final MW reduction was calculated for all four hours. In both instances, subsequent communication with the ICSP answered their questions and mitigated user difficulty for the second and third events.

Additional detail regarding findings from process evaluation activities and their methodology is in *Appendix A.3.1 Process Evaluation* .

1.8 Cost-Effectiveness Reporting

A detailed breakdown of program finances and cost-effectiveness is presented in Table 8. Total resource cost (TRC) benefits were calculated using gross verified impacts. Per the TRC Order, 75% of the customer incentive payment is used as a proxy for the participant cost when calculating the TRC ratio for the program. PYTD values represent PY9 costs and benefits, and P3TD values represent phase costs and benefits up to PY9. Net present value (NPV) PYTD costs and benefits are expressed in PY9 dollars. NPV costs and benefits for P3TD financials are expressed in PY8 dollars.

Table 8. Summary of Demand Response Program Finances–Gross Verified

Row #	Cost Category	PYTD ($1,000)		P3TD ($1,000) [6]	
1	EDC Incentives to Participants	$980		$910	
2	EDC Incentives to Trade Allies	-		-	
3	Participant Costs (net of incentives/rebates paid by utilities)	($245)		($228)	
4	**Incremental Measure Costs (Sum of rows 1 through 3) [1]**	**$735**		**$683**	
		EDC	**CSP**	**EDC**	**CSP**
5	Design & Development [2]	-	-	-	-
6	Administration, Management, and Technical Assistance [3]	$39	-	$184	-
7	Marketing [4]	-	-	-	-
8	Program Delivery [5]	-	$267	-	$746
9	EDC Evaluation Costs	-		-	
10	SWE Audit Costs	-		-	
11[6]	**Program Overhead Costs (Sum of rows 5 through 10) [1], [6]**	$305		$931	
12	NPV of increases in costs of natural gas (or other fuels) for fuel switching programs	-		-	
13	**Total NPV TRC Costs (Net present value of sum of rows 4, 11, and 12) [1], [7]**	**$1,040**		**$1,613**	
14	Total NPV Lifetime Electric Energy Benefits				
15	Total NPV Lifetime Electric Capacity Benefits	$6,188		$5,749	
16	Total NPV Lifetime Operation and Maintenance (O&M) Benefits	-		-	
17	Total NPV Lifetime Non-Electric Benefits (Fossil Fuel, Water)	-		-	
18	**Total NPV TRC Benefits [8] (Sum of rows 14 through 17) [8], [1]**	**$6,188**		**$5,749**	
19	**TRC Benefit-Cost Ratio [9]**	**5.95**		**3.56**	

[1] May not sum to total due to rounding.
[2] All costs for Plan Design and Development are portfolio level costs and are assigned to customer sectors at the end of the phase. These portfolio costs are not assigned to specific programs.
[3] Includes rebate processing, tracking system, general administration, program management, general management and legal, and technical assistance.
[4] Includes the marketing ICSP and marketing costs by program ICSPs.
[5] Includes CSP rebate processing, direct program management, customer support, technical assistance to customers, site visits, legal, QA/QC documentation. These costs cannot be quantified separately and are included as "Program Delivery" costs.
[6] P3TD amounts are discounted back to PY8.
[7] Total TRC Costs includes Total EDC Costs and Participant Costs.
[8] Total TRC Benefits equals the sum of Total Lifetime Electric and Non-Electric Benefits. Benefits include: avoided supply costs, including the reduction in costs of electric energy, generation, transmission, and distribution capacity, and natural gas valued at marginal cost for periods when there is a load reduction.
[9] TRC Ratio equals Total NPV TRC Benefits divided by Total NPV TRC Costs.

1.9 Status of Recommendations

Overall, the Demand Response Program is on track to meet the Act 129 demand reduction goal for Phase III. PPL Electric Utilities averaged 126.7 MW per event hour during PY9 and exceeded the required minimum demand savings for each event of 85% of 92 MW or 78.2 MW. The program is cost-effective, with P3TD TRC Benefit-Cost ratio of 3.6. Participants are predominantly satisfied with the program overall and with all program design and implementation aspects.

The impact and process evaluation activities in PY9 led to the following findings and recommendations from Cadmus to PPL Electric Utilities, along with a summary of how PPL Electric Utilities plans to address the recommendation in program delivery (Table 9).

Finding: Participants are satisfied with the program overall. Of the 10 respondents interviewed, six said they were *very satisfied* with the program, and two said they were *somewhat satisfied.* No participants said they were dissatisfied with the program overall. (See *Participant Satisfaction* section). Interview respondents said the program is working as intended and that the notification timing is a main strength of the program. Respondents said the duration and frequency of events did not hinder their ability to participate.

Conclusion: Customer satisfaction with the program design and implementation are indicative of the upfront investment by PPL Electric Utilities and the ICSP to develop detailed operational plans. Participation in the program, once initial training is completed, is straightforward with well-defined protocols. The program is well designed to provide adequate flexibility and transparency to participants while also ensuring that minimum load reduction targets are met.

Finding: As of December 2017, participants have not yet received the incentive payment because the ICSP waits for the annual evaluation to determine verified peak reductions before processing incentive payments. Two interview respondents said the payment timing was inadequate, particularly in comparison to the quarterly incentive payments they receive through PJM's program. (See

Program Benefits and Costs section.)

Conclusion: The lengthy period between event participation and incentive payment is a concern for some customers, particularly those that incur participation costs as higher production costs because of the curtailment of business operations or backup generator fuel costs.

Recommendation #1: The ICSP should clearly communicate to customers when they should expect to receive the incentive payment. The ICSP could consider paying the incentive earlier, in installments, or within a timeframe amenable to each customer's financial considerations.

Finding: Small C&I and GNE customers produced higher demand savings than the ICSP reported, as shown in Table 4.

Conclusion: Though each small C&I and GNE customer provided a relatively small amount of demand response capacity, together these customers performed as expected and contributed a small but significant share of the achieved savings.

Recommendation #2: The ICSP could consider enrolling more small C&I and GNE customers as a hedge against possible under-performance of large C&I customers with significant enrolled capacity.

Finding: Baselines for many small C&I and GNE facilities that the ICSP estimated by day-matching tended to be underestimated, as *Appendix A* explains. Cadmus employed individual regressions to estimate baselines for all GNE and small C&I facilities and limited the baseline days to 30 non-holiday, non-event weekdays with the highest PJM day-ahead forecasts.

Conclusion: The *ex ante* savings reported by the ICSP underestimated the achieved demand savings.

Recommendation #3: In future evaluations, Cadmus plans to employ regression analysis to estimate baselines of small C&I and GNE customers or any customer with significant air conditioning loads. The ICSP could reconsider its baseline estimation approach for small C&I and GNE customers to better account for the impacts of weather on loads.

Finding: Some participants with large enrolled capacity appear to have adjusted their consumption of electricity on the day before an event in response to receiving advance notifications. *Appendix A* analyzes load impacts on notification days.

Conclusion: The Evaluation Framework for Pennsylvania Act 129 Phase III Programs gave evaluators discretion about whether to include notification days in the basis window. Since electricity consumption on notification days was outside the normal or expected range for many participant facilities, Cadmus concluded notification days should not be included in the customer baseline basis window. Cadmus excluded these days from the basis window when estimating baselines.

Recommendation #4: Cadmus plans to exclude notification days from the basis window in future evaluations.

Finding: The savings realization rate was close to 100%, and, for large C&I participants, which supplied 95% of the demand savings, Cadmus' savings estimates were close to the ICSP's. This may be attributed to the alignment of baseline calculations methods, particularly for the largest savers, between the ICSP and Cadmus. *Appendix A* presents savings realization findings.

Conclusion: Alignment of the ICSP and Cadmus' baseline calculation methods for large C&I facilities using day matching produced similar savings estimates, resulting in a realization rate near 100%.

Recommendation #5: If requested by PPL Electric Utilities and the ICSP, Cadmus plans to continue to perform an analysis of baseline calculation methods for new participants and share its findings with ICSP, so there is opportunity for alignment.

1.9.1 Status of Recommendations for Program

Table 9 contains the status of each PY9 recommendation made to PPL Electric Utilities.

Table 9. Status of Recommendations

Demand Response Program		
Recommendation Number	**Recommendation**	**EDC Status of Recommendation (Implemented, Being Considered, Rejected and Explanation of Action Taken by EDC)**
1	The ICSP should clearly communicate to customers when they should expect to receive the incentive payment. The ICSP could consider paying the incentive earlier, in installments, or within a timeframe amenable to each customer's financial considerations	Being considered
2	The ICSP could consider enrolling more small C&I and GNE customers as a hedge against possible under-performance of large C&I customers with significant enrolled capacity.	Being considered, although PPL and the ICSP may want to consider enrolling a few larger customers, instead of numerous smaller customers, as a hedge.
3	In future evaluations, Cadmus plans to employ regression analysis to estimate baselines of small C&I and GNE customers or any customer with significant air conditioning loads. The ICSP could reconsider its baseline estimation approach for small C&I and GNE customers to better account for the impacts of weather on loads.	Being considered
4	Cadmus plans to exclude notification days from the basis window in future evaluations.	Implemented (agree)
5	If requested by PPL Electric Utilities and the ICSP, Cadmus plans to continue to perform an analysis of baseline calculation methods for new participants and share its findings with ICSP, so there is opportunity for alignment.	Implemented (agree)

Appendix A. Evaluation Detail–Demand Response Program

A.1 Gross Impact Evaluation

The principal objective of the Demand Response Program impact evaluation was to estimate participant load impacts from Act 129 events and to determine whether PPL Electric Utilities complied with the demand response load reduction targets of Act 129. During PY9, Pennsylvania initiated three Act 129 demand response events on June 13, 2017, July 20, 2017, and July 21, 2017.

This appendix describes the methodology, including sampling and savings estimation, for estimating the program load impacts.

A.1.1 Methodology

EM&V Sampling Approach

In PY9, 93 facilities participated in one or more Act 129 demand response events. Table A-1 shows the number of participant facilities by customer type stratum. About two-thirds of participants were small commercial facilities. Cadmus estimated load impacts for all participant facilities except one. As discussed further below, it was not possible to estimate savings for one small C&I facility because this facility's readings were estimates, not actuals, during event hours.

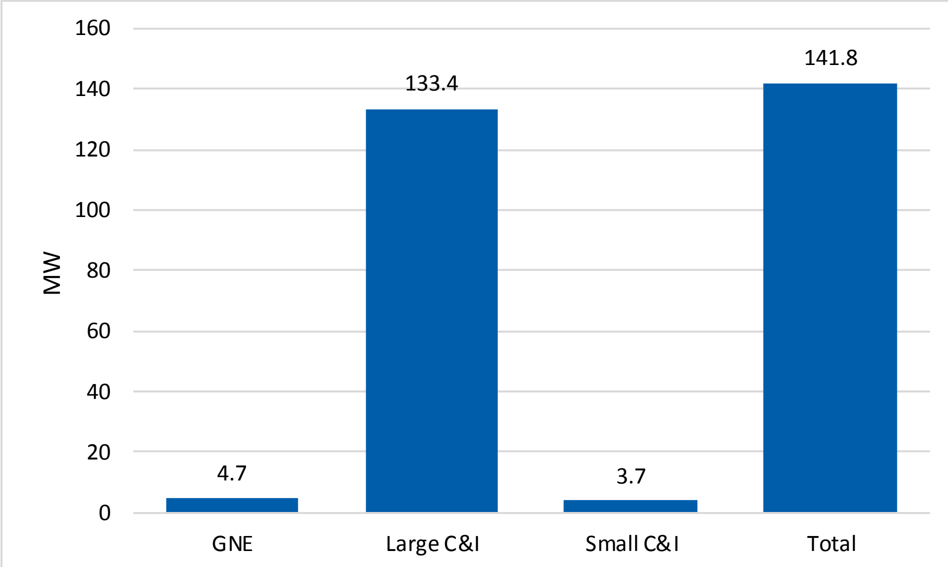
Table A-1. PY9 Program Sampling Strategy

Stratum	Population Size	Target Levels of Confidence & Precision	Target Sample Size	Achieved Sample Size	Evaluation Activity
GNE	10	N/A	10	10	Analysis of load impact data
Large Commercial and Industrial	23	N/A	23	23	Analysis of load impact data
Small Commercial	60	N/A	60	59	Analysis of load impact data
Program Total	**93**	**N/A**	**93**	**92**	**Analysis of load impact data**

As Figure A-1 shows, although they represented 65% of participant facilities, small commercial facilities contracted for only 3.7 MW or 2.6% of the program's enrolled capacity.[3] Large C&I customers contracted for 133.4 MW or 94% of the program's enrolled capacity. GNE customers contracted for the remaining capacity of 4.7 MW.

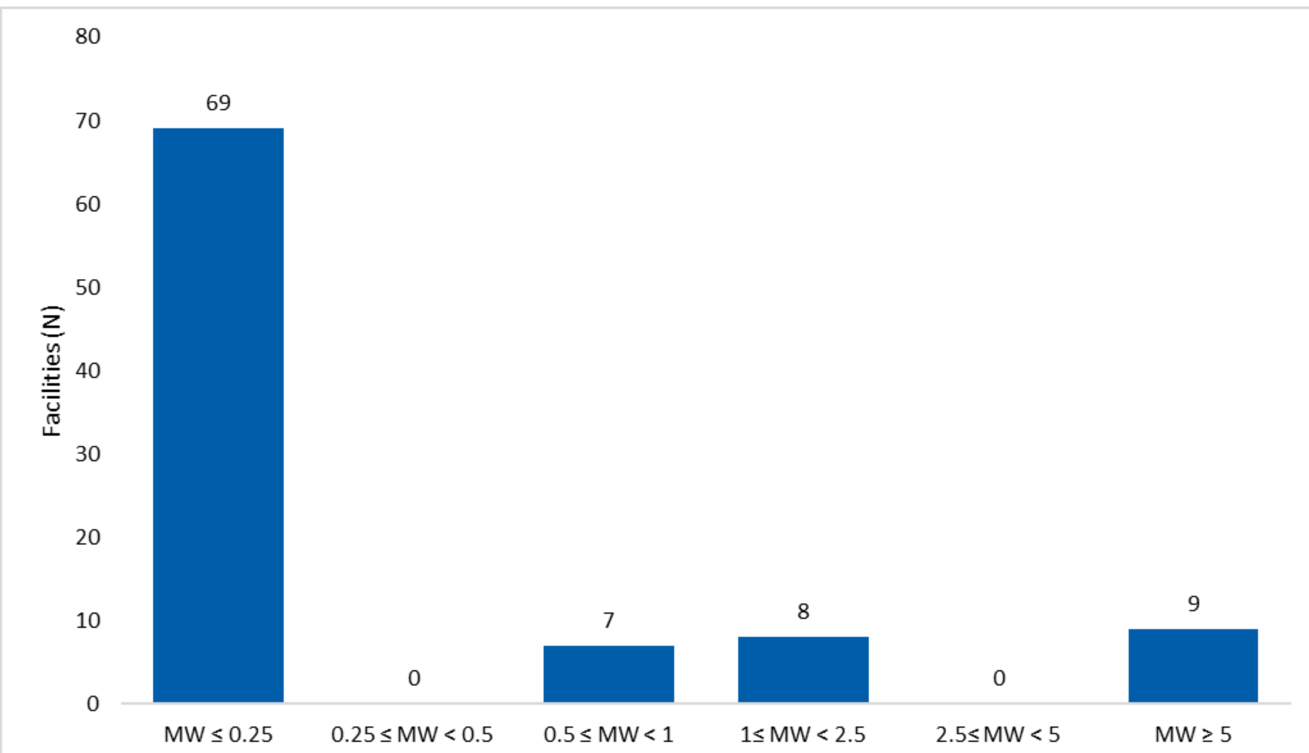
3 Contracted capacity refers to the capacity committed by the facility to CPower and enrolled in the program. The capacity provided by the facility during Act 129 events may have differed from the contracted amount.

Figure A-1. Enrolled Demand Response Capacity by Customer Segment



As Figure A-2 shows, most enrolled demand response capacity was provided by a small number of facilities. Of 93 participants, 69, or 74%, each contracted for less than 250 kW. Only 17 facilities contracted to supply one or more megawatts. Collectively, these facilities contracted for 94% of the program's enrolled capacity.

Figure A-2. Distribution of Demand Response Program Enrolled Capacity



Note: To protect the identity of participants, this figure does not display bins above 5 MW.

Ex Post Verified Savings Methodology

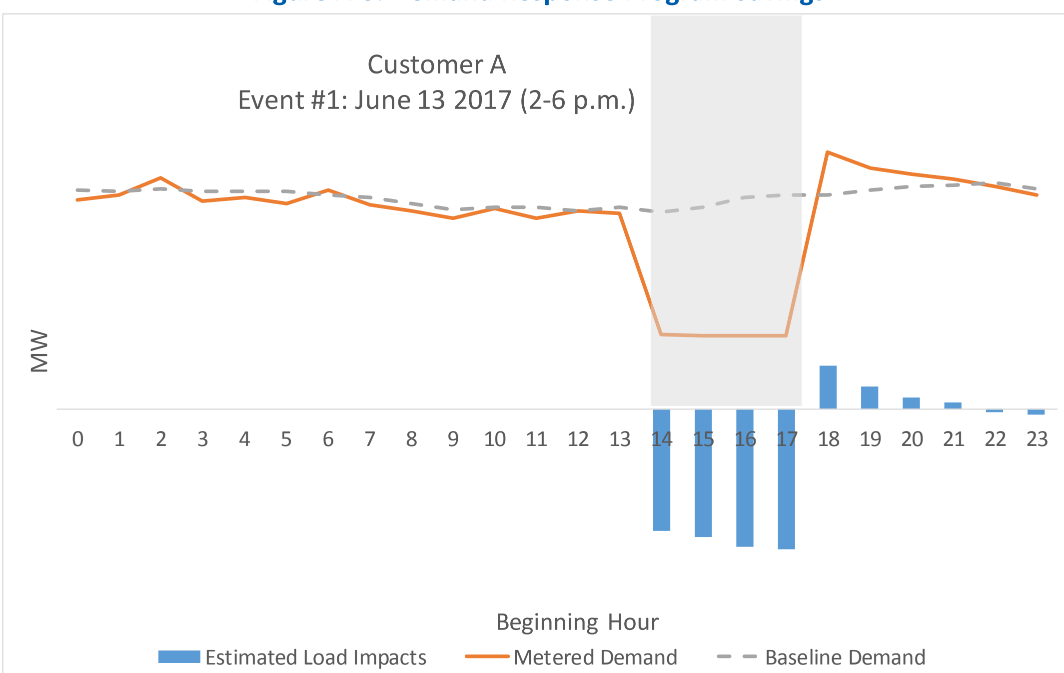
Cadmus analyzed AMI interval consumption data for individual participant facilities. A facility was defined as the area over which the participant's electricity consumption was metered and the load reductions measured during PY9 Demand Response Program period (June 1, 2017–September 30, 2017). Cadmus estimated the facility load impacts as the difference between baseline electricity demand and metered demand, as shown in this equation:

$$\text{kW impact} = \text{Baseline kW} - \text{Metered kW}$$

Baseline demand is a counterfactual and represents what the facility's load would have been if the load curtailment event had not been called. The baseline is unobservable and must be estimated. Accurate estimation of load impacts requires establishing a valid baseline.

Figure A-3 illustrates the demand response event savings estimation for a hypothetical participant facility (Customer A). The shaded area shows the event window between 2:00 p.m. and 6:00 p.m. The solid line shows the metered consumption, and the gray lines shows the estimated baseline. The demand savings shown as blue bars represent the reduction in demand relative to the baseline caused by the event. Also, Figure A-3 depicts an increase in load, or snapback, after the event, shown as metered load lying above the baseline during hours 18 through 20. The average demand savings per event hour are calculated as the average of the estimated hourly load reductions between 2:00 p.m. and 6:00 p.m.

Figure A-3. Demand Response Program Savings



Data Collection

Cadmus collected data from several sources to evaluate the PY9 Demand Response Program impacts. Table A-2 lists the data and sources.

Table A-2. Data Sources

Data	Population	Period	Variables	Source
Customer information system data	Demand Response Program participant facilities	From beginning of enrollment to end of summer 2017	Customer name, account number, business segment, ICSP baseline calculation method, enrolled MW, event hour participation indicators and reported load reductions, advance notification times, PJM economic market participation dates	CPower (ICSP)
PJM day-ahead forecasts and Act 129 event dates and hours	PPL Electric Utilities Demand Response Program participants	Summer 2017	Event dates and hours	PPL Electric Utilities, CPower (ICSP), PJM Interconnection LLC website
Facility interval consumption data	PPL Electric Utilities Demand Response Program participants	April 1, 2017–September 30, 2017	15 minute or hour interval kWh, estimated read indicator	PPL Electric Utilities
Weather	11 weather stations in PPL Electric Utilities service area	June 2017–August 2017	Dry-bulb temperature	NOAA
Line losses	Commercial and industrial electric utility customers	Phase III Act 129	Line loss factor	PA Technical Resource Manual (2016), Table 1-4

PPL Electric Utilities provided 15-minute or one-hour interval consumption data between April 1, 2017, and September 30, 2017, for 93 participant facilities. Cadmus aggregated all facility 15-minute interval data to the hour level. The energy consumption data included a very small percentage (0.1%) of missing readings. Also, a small percentage of intervals was estimated or included one or more estimated or missing 15-minute intervals. Cadmus flagged these observations and set them to missing for the analysis. Estimated readings were not used in the calculation of facility baselines or in estimating savings. In fact, it was not possible to estimate demand savings for one small commercial facility because its consumption was estimated during each event hour in PY9.

Cadmus also screened the data for outliers but did not remove any observations. Before June 1, 2017, a small number of big box stores had negative readings during a small number of morning hours, but Cadmus inferred from the time of day and outside temperature as well as corroborating articles in the press about solar panel installations by participating big box store chains that these probably represented negative net demand for utility supplied electricity because of on-site solar generation of electricity.

Table A-3 summarizes the outcome of the kWh data cleaning process.

Table A-3. Energy Data Summary

Observations	Number	Percentage
Participant facilities	93	100%
Total observations	408,456	100%
Obs. with missing kWh readings	261	0.1%
Obs. with estimated kWh readings	7,407	1.8%
Obs. in final analysis sample	400,788	98.1%

The ICSP provided Cadmus information about each participant facility's business segment, customer baseline calculation method, enrolled MW, participation in each event hour, and event advance notification times. The ICSP also provided information about facilities that had participated in the PJM economic market. During PY9, three Act 129 participant facilities participated in the PJM market.

Cadmus located the closest National Oceanic and Atmospheric Administration (NOAA) weather station and mapped hourly temperature data to the kWh data. We mapped weather data to participant facilities from 11 stations across the PPL Electric Utility service area. The average temperature during event hours was 90.2°F. Table A-4 shows summary statistics for the analysis sample, including weekday event and non-event hours between 2:00 p.m. and 6:00 p.m. for all facilities and by customer segment. Participants consumed an average of 0.93 MWh per event hour per facility, although there was significant variation in consumption between customer segments. Large C&I facilities consumed about 2.4 MWh per hour per facility, while small C&I participants consumed about one-tenth of this amount.

The ICSP estimated average savings per participant facility per event hour of 2.4 MW, but on average, only 52% of facilities participated in each event hour. Small C&I facilities participated in only 33% of event hours because only one of 60 facilities participated in the July 20 event and none participated in the July 21 event.

Table A-4. Sample Summary Statistics

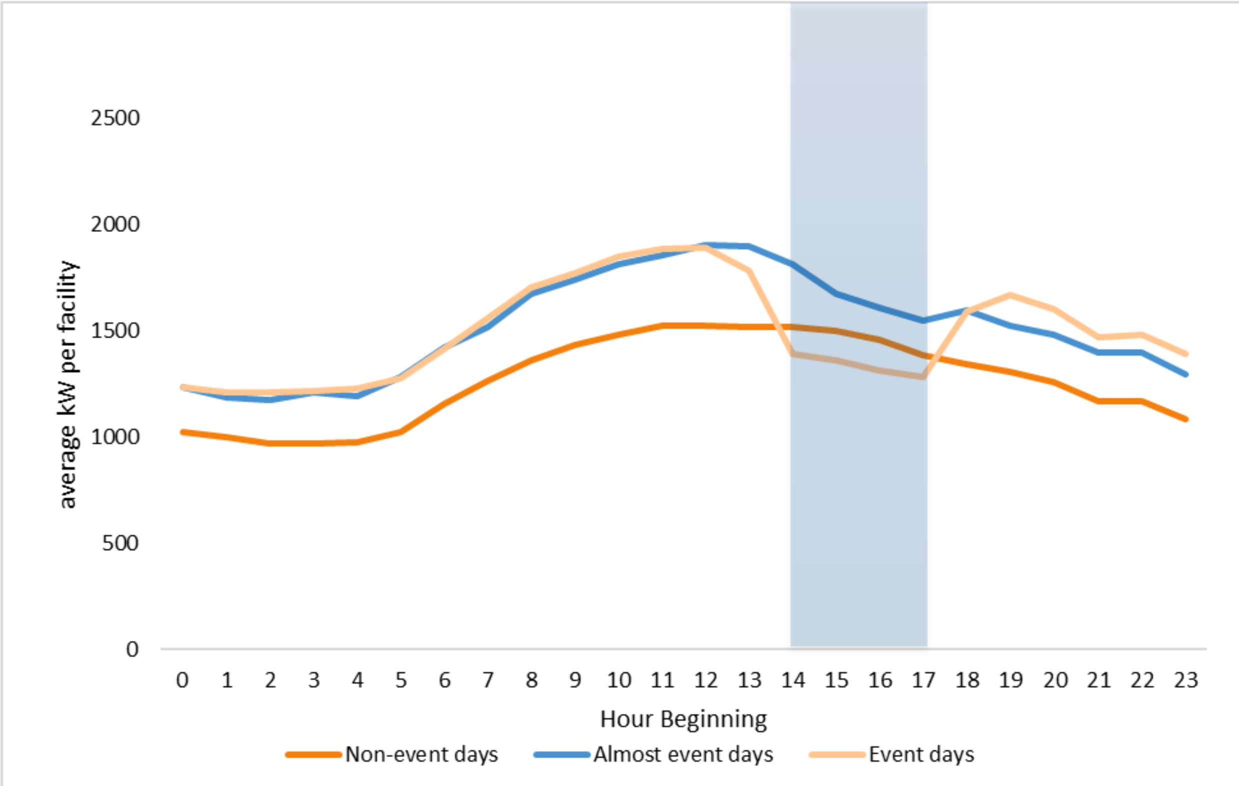
	All Facilities	GNE	Large C&I	Small C&I
Panel A: Event Hours				
kWh/hour	936.4	1339.3	2408.7	281.2
	(2294.3)	(2080.4)	(3950.0)	(125.5)
Outside Temperature (°F)	90.2	91.1	91.3	89.6
	(4.2)	(3.4)	(2.8)	(4.6)
Event Participation (=1 if Yes, =0 if No)	0.52	0.93	0.83	0.33
	(0.50)	(0.25)	(0.37)	(0.47)
CPower Savings Estimate	2384.4	283.0	5896.8	-11.0
	(5813.4)	(543.7)	(8056.6)	(64.8)
PJM Economic Participation	0	0	0	0
	0.0	0.0	0.0	0.0
N	1,116	120	276	720
Panel B: Non-event Hours				
kWh/hour	2041.4	1467.7	6802.1	262.3
	(5058.5)	(1787.9)	(8324.8)	(122.4)
Outside Temperature (°F)	74.3	75.1	74.5	74.1
	(9.8)	(9.8)	(9.8)	(9.8)
Event Participation (=1 if Yes, =0 if No)	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0
CPower Savings Estimate	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0
PJM Economic Participation	0.003	0.000	0.011	0.000
	(0.05)	0.00	(0.10)	0.00
N	46,132	4,960	11,408	29,764

Note: All summary statistics are sample hourly averages for hours between 2:00 p.m. and 6:00 p.m. on event and non-event days between April 1, 2017 and September 30, 2017. Sample standard deviations in parentheses.

For GNE, large C&I, and small C&I facilities, Figure A-4**,** Figure A-5**,** and Figure A-6 show the average kWh per hour per facility on event days, "almost Act 129 event days," and all other non-holiday weekdays between June 1, 2017, and September 30, 2017, that were not notification days. Almost-event days were July 12, 2017, and July 13, 2017. In PY9, these days had the highest day-ahead PJM forecasts that did not qualify them as Act 129 days and provide a natural baseline for assessing the impact of Act 129 events. These figures show demand at the meter and do not account for line losses.

For GNE facilities, the Act 129 event impacts between 2:00 p.m. and 6:00 p.m. are clearly evident as a reduction in load relative to demand on almost-event days. On average, demand on non-event days was significantly less than was demand on event or almost-event days, and the difference was greatest during the late morning and early afternoon. Event days tended to be warmer, and space conditioning was a major electricity end use in GNE facilities. The difference between event and non-event days suggests that many of the non-event days may not provide an accurate baseline for event days.

Figure A-4. Average kW per GNE Participant Facility in PY9



The impacts of Act 129 events between 2:00 and 6:00 p.m. on loads of large C&I facilities are also evident in Figure A-5. Average demand per facility during non-event hours (outside the 2:00 p.m. to 6:00 p.m. window) was significantly less on event days than on non-event or almost-event days. This suggests that at least some participants may have reduced their loads in preparation for the events on the days before events or the event days in response to receiving event notifications. On non-event days, average demand per facility was constant and suggests demand was not sensitive to weather. On almost-event days, there was a reduction in load relative to non-event days between 2:00 p.m. and 6:00 p.m. This may have been the result of PJM market economic program participation by several Act 129 participants. Four large C&I participants with significantly more than 20 MW of combined enrolled demand response capacity participated in the PJM market on July 12 or July 13.

Figure A-5. Average kW per Large C&I Participant Facility in PY9

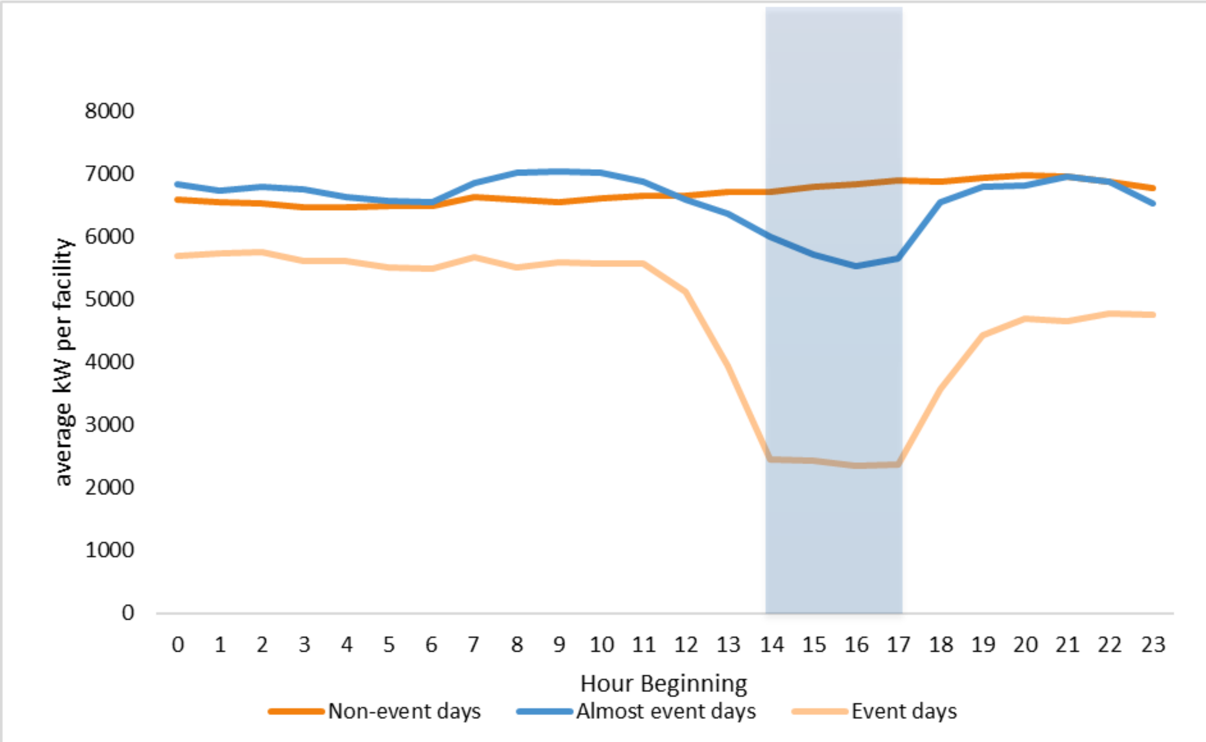
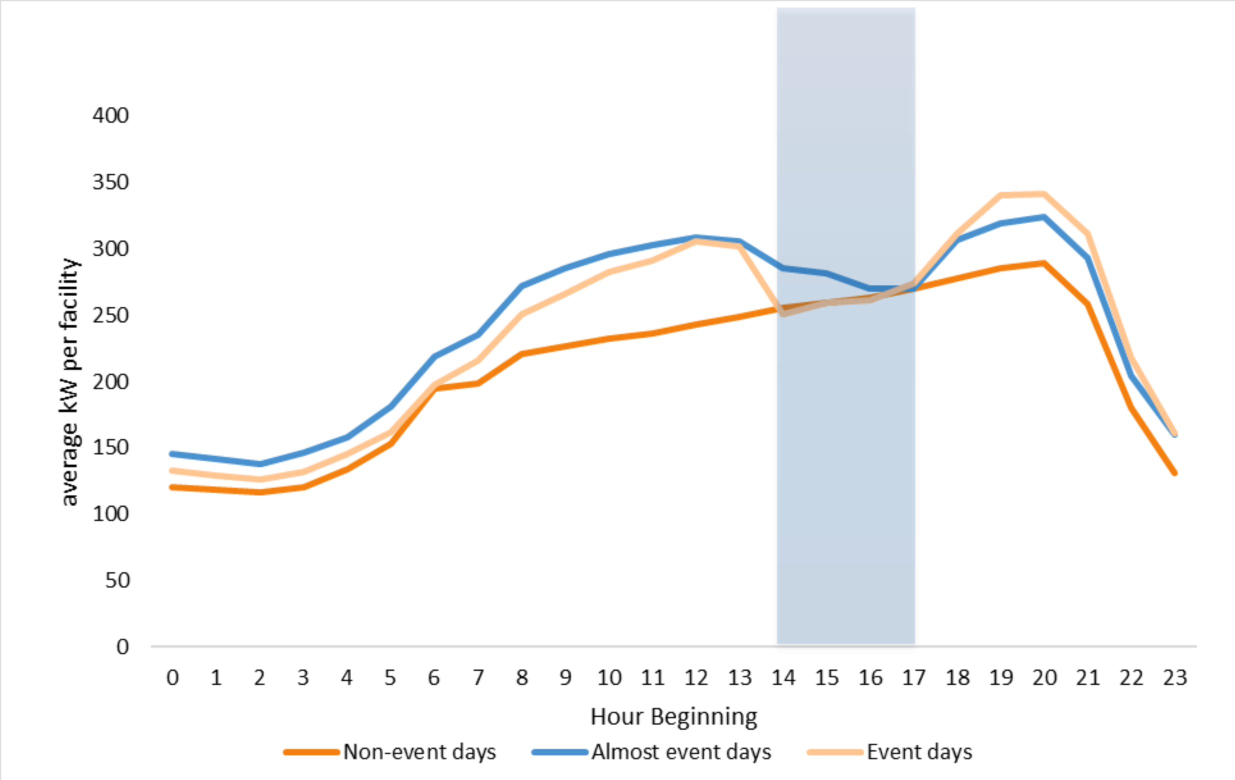


Figure A-6 shows loads for small C&I facilities on the June 13 event, non-event days, and almost-event days. Fifty-nine small C&I facilities participated in the June 13 event. Loads on non-event days were lower than on event and almost-event days and do not exhibit a shape suggestive of significant energy consumption for air conditioning, again suggesting that some non-event days may not provide a valid baseline.

Figure A-6. Average kW per Small C&I Participant Facility in PY9



Baseline Calculation Approach

Day-Matching Customer Baselines and Regression Baselines

Cadmus estimated individual consumption baseline for each participant facility and event using either a day-matching approach or regression. Day-matching identifies a set of nearby, non-event, non-holiday weekdays for each event day, referred to as the *basis window*. For each event hour, the baseline is the average consumption during the same hour of the days or subset of days in the basis window. Cadmus considered a variety of general day-matching methods for estimating the baselines of participating facilities:

- *Y Previous Days*: This is the average load of Y days in the CBL basis window.
- *X Highest of Y Previous Days*: This is the average load of the X days with highest loads of Y days in the basis window.
- *Y Previous Days of Same Day Type*: This is the average load of Y days of the same day type (e.g., Wednesday) in the basis window. For example, if Y=3 and the event occurs on a Wednesday, the CBL basis window would only include three previous Wednesdays.

When applying a day-matching method, Cadmus excluded the following types of days from the basis window:

- Weekend days
- Days with average load between 2 p.m. and 6 p.m. less than 25% of the average load of all days in the baseline window. This exclusion follows PJM protocol and should result in the exclusion of most days when a facility had abnormally low consumption. Cadmus replaced excluded days with the next permissible day.
- Holidays
- Facility closures
- Previous event days
- Weekdays more than 45 days before the event day
- PJM economic participation days
- Act 129 notification days

Cadmus did not make any adjustments to the estimated baseline based on the difference between the baseline and the metered load during hours preceding the event. Adjustments of this kind were not permitted because PPL Electric Utilities' Demand Response Program involved day-ahead notification of Act 129 events.[4] Below, Cadmus provides evidence that some participant facilities adjusted their loads in response to the advance notifications.

Day matching was the method employed by the ICSP to estimate impacts and make settlement calculations. By aligning, to the extent possible, its day matching baseline calculation methods with Cadmus, the ICSP eliminated a possible source of difference between the reported and evaluation impact estimates.

Cadmus employed regression analysis as the second baseline calculation approach. Regression involves estimating an equation to predict hourly consumption as a function of multiple independent variables such as day of the week, hour of the day, and weather. Regression controls for the impacts of weather on energy consumption better than day-matching and is expected to be superior to day-matching especially for facilities with weather-sensitive loads.

Selection Facility Baseline Calculation Method

For large C&I participant facilities, Cadmus tested the predictive accuracy of different day-matching and regression baseline calculation methods and selected the most accurate method for each facility.

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[4] See Goldberg, Miriam, and G. Kennedy Agnew. *Measurement and Verification for Demand Response.* Prepared for the National Forum on the National Action Plan on Demand Response: Measurement and Verification Working Group. 2013. The exception to this rule would be an adjustment based on an exogenous variable such as weather or the PJM day-ahead forecast of load or actual load.

Cadmus used the selected methods to calculate customer baseline demand for the Act 129 demand response events in 2017.

To identify the most accurate baseline method for large C&I participant facilities, Cadmus used AMI meter data from summer 2016 to test the predictive accuracy of different day-matching and regression baseline calculation methods.[5] Cadmus tested the accuracy of each baseline method by comparing predicted baseline consumption to metered consumption in each hour between 2:00 p.m. and 6:00 p.m. on 38 non-holiday weekdays between June 15, 2016, and September 1, 2016. The difference between the estimated baseline and the metered consumption was the prediction error. This error is expected to be zero if the baseline predicts accurately since there were no Act 129 events in 2016.

For each facility, Cadmus selected the day-matching or regression baseline method that performed best in terms of accuracy, bias, and variability (risk). It assessed the accuracy of the baseline using several statistics including relative root mean squared error (RRMSE), mean absolute percentage error (MAPE), and median percentage prediction error. Cadmus also calculated and plotted the distribution of errors to see if there were a small number of hours where models predicted poorly.

For each large C&I facility, Cadmus tested the predictive accuracy of 10 day-matching methods and two regression models:

- 2 previous days
- 3 previous days
- 4 previous days
- 5 previous days
- 10 previous days
- 3 of 5 previous days with highest average load during event hours
- 4 of 5 previous days with highest average load during event hours
- 7 of 10 previous days with highest average load during event hours
- 3 previous days of the same day type (e.g., Wednesdays)
- 4 previous days of the same day type
- Regression 1
- Regression 2

The first regression model included as regressors interactions between indicator variables for each hour between 2:00 p.m. and 6:00 p.m. and indicator variables for day of the week and a cubic polynomial in outdoor temperature. The second substituted a cooling degree hour (CDH) variable and a heat buildup

5 Cadmus tested the predictive accuracy of the model for each hour between 2:00 p.m. and 6:00 p.m. on summer, non-holiday weekdays in 2016 that would have qualified as Act 129 days.

variable for the temperature variables but was otherwise the same.[6] Cadmus applied data filters to the regressions like those applied to day-matching data.[7]

Cadmus subjected large C&I facilities selected for regression to additional specification testing by testing the predictive accuracy of 17 different regression model specifications, including the original ones, on 30 non-holiday, non-event weekdays in 2017 that had highest PJM day-ahead forecasts but that did qualify as Act 129 demand response days. Cadmus selected the specification that predicted best to estimate the event day baselines for the facility. The regression specifications are described in Table A-5. Models 1 and 2 correspond to the specifications from the original round of testing.

Table A-5. Baseline Regression Model Specifications

Model	Dependent Variable	Class Variables	Independent Variables	Intercept
1	kWh/Hour	Day Hour	Day*Hour Temp $Temp^2$ $Temp^3$	No
2	kWh/Hour	Day Hour	Day*Hour CDD75 CDD75_Buildup	No
3	kWh/Hour	Day	Day	No
4	kWh/Hour	Day Hour	Hour Day	No
5	kWh/Hour	Day Hour	Hour Day CDD75	No
6	kWh/Hour	Day Hour	Hour Day CDD75_Buildup	No
7	kWh/Hour	Day	Day CDD75	No
8	kWh/Hour	Day	Day CDD75 CDD75_Buildup	No
9	kWh/Hour	Day	Day CDD75_Buildup	No
10	kWh/Hour	Hour	Hour	No
11	kWh/Hour	Hour	Hour CDD75	No
12	kWh/Hour	Hour	Hour CDD75_Buildup	No
13	kWh/Hour	Hour	Hour CDD75_Buildup	No
14	kWh/Hour		CDD75	Yes
15	kWh/Hour		CDD75 CDD75_Buildup	Yes
16	kWh/Hour		CDD75_Buildup	Yes
17	kWh/Hour	Day Hour	Day Hour CDD75 CDD75_Buildup	No

Originally, Cadmus subjected GNE and small C&I participant facilities to the same baseline testing process. Regression analysis provided the most accurate baselines for many, but not all, such facilities. However, Cadmus determined that the day-matching calculation methods selected for small GNE and small C&I customers appeared to substantially under-predict the counterfactual baseline on event days

6 The heat buildup variable was the weighted average of CDHs in the preceding 24 hours. The weights were normalized to sum to one and the weight assigned to hour t-1 was 90% of the weight assigned to hour t, so that more recent hours received greater weight.

7 Cadmus excluded weekends, holidays, the day immediately preceding the test day as it was analogous to the notification day, and days with average load during event hours less than 25% of the average load during event hours across all days in the basis window. In addition, the number of days eligible for the window was increased from 45 days to 60 days.

and led to demand savings estimates that were too low. The underprediction was consistent with the patterns between event and non-event days evident in Figure A-4 and Figure A-6.

As a result, Cadmus implemented two changes to the evaluation plan for calculating baselines for GNE and small C&I facilities. First, Cadmus used regression analysis to construct the baseline for all GNE and small commercial facilities. Second, it limited the days used in estimating the baseline model to the 30 non-holiday weekdays with the highest PJM day-ahead forecasts that were neither event days nor event notification days. This corresponded to days with PJM day-ahead forecasts for one or more hours that were 81% or more of the PJM summer peak demand forecast. Cadmus tested the sensitivity of the savings estimates to different PJM forecast cutoffs and found that the results were not sensitive to the number between 15 and 30 of included non-qualifying days with the highest day-ahead forecasts.

Table A-6 shows counts of participant facilities by baseline modeling approach for all facilities, by customer segment, and for 17 facilities with capacity enrollments greater than or equal to 1 MW. The large MW facilities accounted for 94% of enrolled capacity.

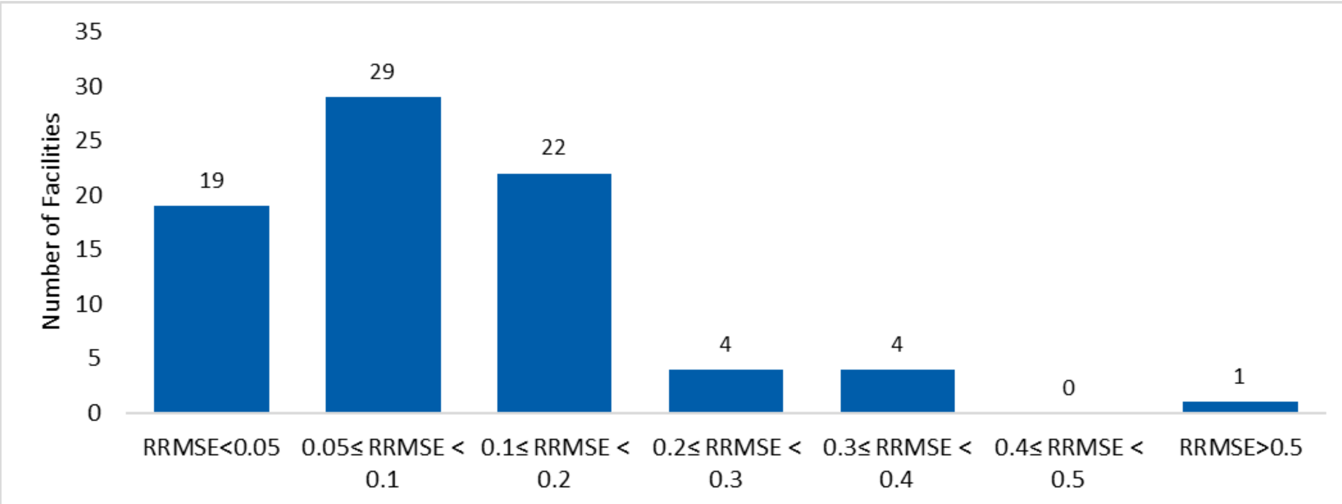
Table A-6. Number of Facilities by Baseline Modeling Approach

Baseline	All facilities	GNE	Large C&I	Small C&I	DR Capacity ≥ 1 MW
2 OF 2	3	0	3	0	2
3 OF 3	1	0	1	0	1
3 OF 5	1	0	1	0	1
4 OF 4	0	0	0	0	0
4 OF 5	1	0	1	0	1
5 OF 5	1	0	1	0	1
7 OF 10	3	0	3	0	3
10 OF 10	1	0	1	0	1
Day of Week 4 of 4	1	0	1	0	1
Day of Week 3 of 3	0	0	0	0	0
Regression	80	10	11	59	6
Total	**92**	**10**	**23**	**59**	**17**
Note: Cadmus could not estimate savings for one facility because all of its kWh readings during event hour were estimated.					

Among large C&I facilities, regression was the most frequently-chosen baseline modeling method. Cadmus used regression analysis for almost half (N=11) of such facilities. Many large C&I facilities used day-matching approaches because they had highly variable day-to-day consumption between 2:00 p.m. and 6:00 p.m., and regression did not predict well. For these facilities, the best predictor of consumption was consumption in recent previous days, so many large C&I facilities selected X-of-Y-previous-day baseline methods.

Cadmus estimated the predictive accuracy of selected baseline methods on non-event, non-holiday, and non-notification weekdays in summer 2017 for hours between 2:00 p.m. and 6:00 p.m. For facilities with regression baselines, the testing was limited to the 30 days with highest PJM day-ahead forecasts. For facilities with day-matching baselines, the testing was conducted on all qualifying days between June 1, 2017, and September 30, 2017. Figure A-7 shows the RRMSE for hourly kWh predictions for facilities with regression baselines.

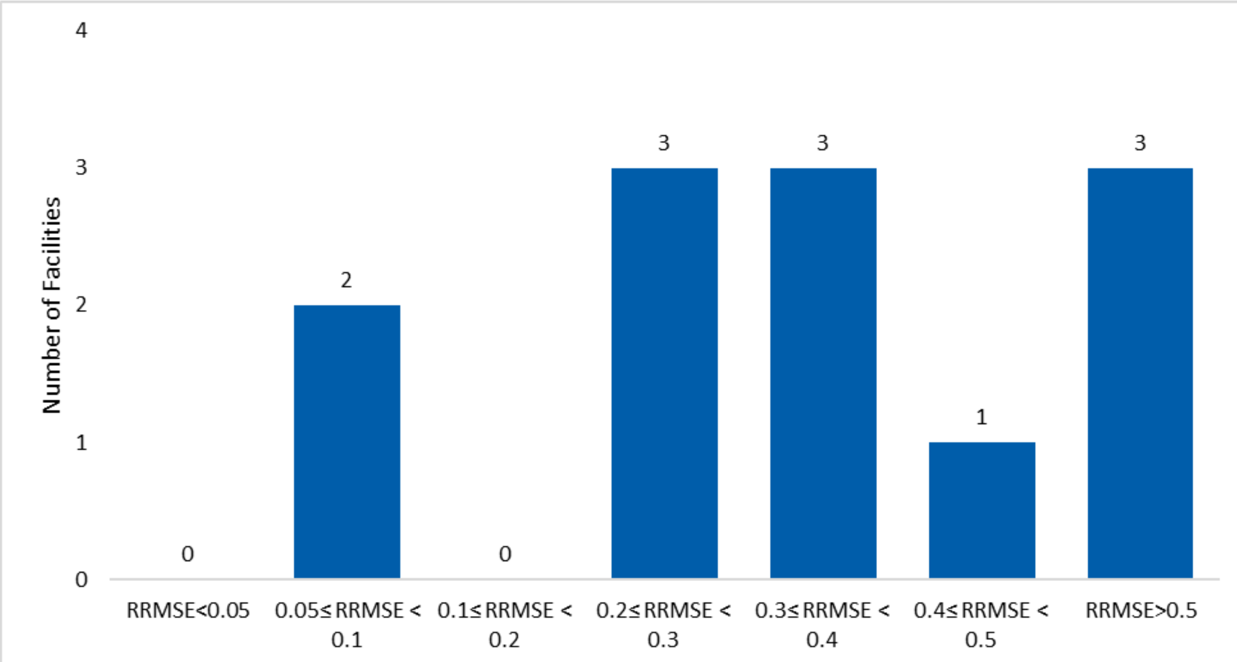
Figure A-7. Predictive Accuracy of Regression Baseline Facilities



Of 79 participant facilities with regression baselines, 70 had RRMSE less than 0.2, which is considered the upper bound of the desired range. Eight of the nine remaining facilities had RRMSE between 0.2 and 0.4, slightly higher than what is considered desirable. Overall, the regressions used to predict baseline consumption demonstrated high predictive accuracy.

Figure A-8 shows the RRMSE for day-matching facilities. The predictive accuracy of the day-matching baselines was not as high as that for the regression baselines. Eight of 12 facilities had RRMSE less than 0.4, but four facilities had RRMSE greater than 0.5. However, although the predictive accuracy of the day-matching baselines for some facilities was less than desired, the day-matching baselines still provided greater accuracy than regression baselines for these facilities.

Figure A-8. Predictive Accuracy of Day-Matching Baseline Facilities



Standard Errors of Demand Savings Estimates

Cadmus calculated 90% confidence intervals for the gross verified demand savings from the standard errors for the savings estimates of individual facilities. For facilities with regression baselines, Cadmus estimated the standard errors for the estimates of average demand savings per event hour using the estimated variances and co-variances of the hourly demand savings estimates. For facilities with day-matching baselines, Cadmus followed SWE's and PJM's guidance to predict loads on non-event days in 2017 and to estimate the margin of error at the 90% confidence level as the root mean square error (RMSE). Cadmus calculated the RMSE for the day-matching baseline using baseline predictions for hours between 2:00 p.m. and 6:00 p.m. on non-holiday, non-event and non-notification days between June 1, 2017, and September 30, 2017.

Act 129 Events in Program Year 9

Table A-7 presents the Act 129 event dates, hours, advance notification date and times, and the average outside temperature during events in PY9.

Table A-7. PY9 Act 129 Events Dates and Times

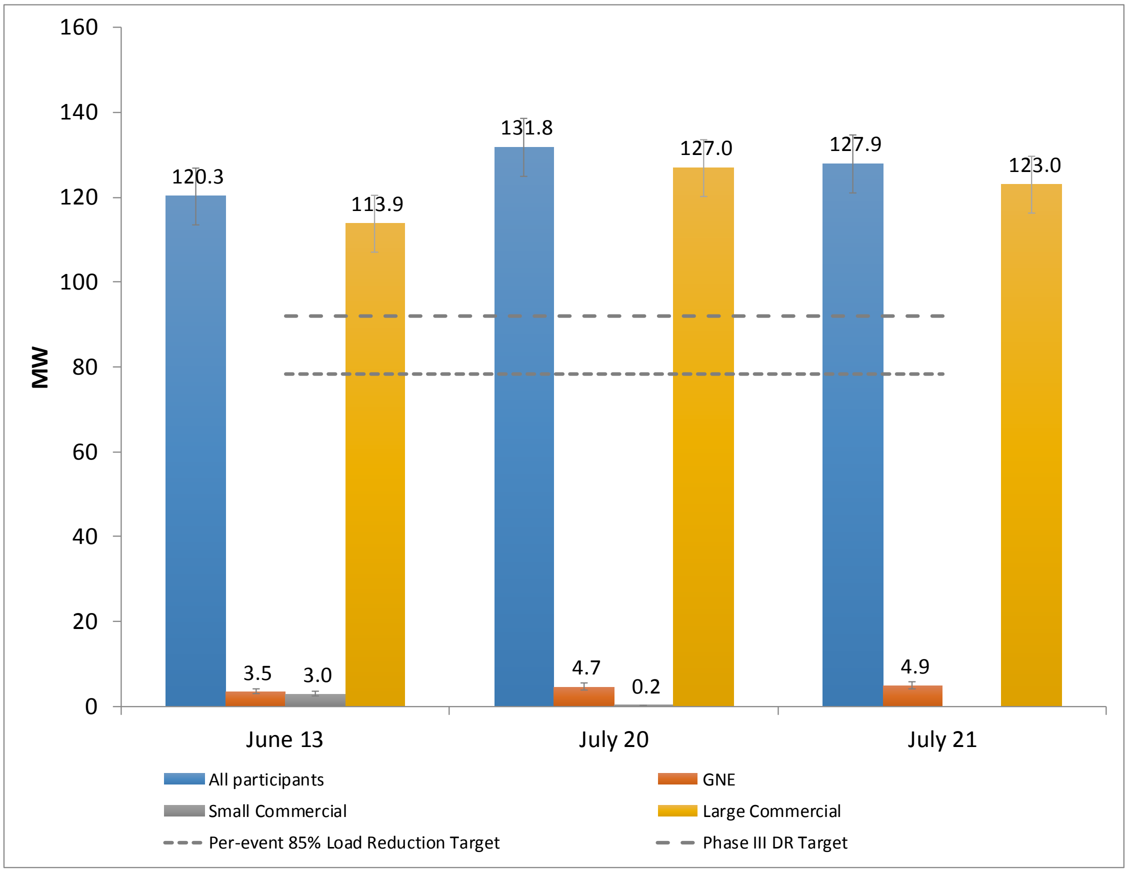
Event Date	Event Hours	Advance Notification Date and Time	Average Outside Temperature (°F) During Event
Tuesday, June 13, 2017	2:00 p.m. - 6:00 p.m.	June 12, 2017, 10:33 a.m.	92.4
Thursday, July 20, 2017	2:00 p.m. - 6:00 p.m.	July 19, 2017, 10:02 a.m.	90.8
Friday, July 21, 2017	2:00 p.m. - 6:00 p.m.	July 20, 2017, 11:02 a.m.	89.5
Note: Advance notification times were obtained from CPower through Cadmus data request.			

Note that the second and third events were on consecutive days. Participants received notification of the July 21, 2017 event before the start of the July 20 event. This may have caused some large C&I customers not to resume normal business operations after the July 20 event ended because another event would occur during the next day.

Discussion of Results

The estimates of program and customer segment demand savings by Act 129 event date are presented in Table 4 and Table 5 in the main body. In Figure A-9, Cadmus also presents the results graphically. Unless noted otherwise, all demand load impacts have been adjusted for line losses.

Figure A-9. PPL Electric Utilities Act 129 Gross Verified Demand Savings



Notes: Estimates based on Cadmus analysis of AMI interval consumption data for participant facilities. Error bars show 90% confidence intervals. The Phase III demand response target for PPL Electric Utilities is 92 MW. All savings estimates were adjusted for line losses.

PPL Electric Utilities achieved demand savings of 120 MW on June 13, 2017, 132 MW/ on July 20, 2017, and 128 MW on July 21, 2017, easily exceeding the Act 129 target for each event of 78.2 MW. Furthermore, across the three events, PPL Electric Utilities averaged 126.7 MW, putting the program on track to exceed PPL Electric's target of 92 MW for Phase III of Act 129. As Figure A-9 shows, large C&I customers were responsible for more than 95% of the demand response savings.

Table **A**-8 reports the evaluation estimated demand savings, metered demand, estimated baseline demand, and the percentage demand savings by event for each customer segment and the program.

Table A-8. Event Demand Savings and Baseline Demand

	Event	Demand Savings (MW/hour)	Metered Demand (MW/hour)	Baseline Demand (MW/hour)	Relative Precision at 90% C.L.	Percentage Demand Savings
Small C&I	June 13, 2017	3.0	16.7	19.7	15%	15.1%
	July 20, 2017	0.2	0.0	0.2	13%	81.7%
	July 21, 2017	NA	NA	NA	NA	NA
Large C&I	June 13, 2017	113.9	42.7	156.6	6%	72.7%
	July 20, 2017	127.0	52.0	179.0	5%	71.0%
	July 21, 2017	123.0	58.4	181.4	5%	67.8%
GNE	June 13, 2017	3.5	9.8	13.3	16%	26.1%
	July 20, 2017	4.7	14.2	18.8	18%	24.7%
	July 21, 2017	4.9	14.0	18.9	17%	26.1%
Event	**June 13, 2017**	120.3	69.2	189.5	6%	63.5%
	July 20, 2017	131.8	66.2	198.0	5%	66.6%
	July 21, 2017	127.9	72.4	200.3	5%	63.9%
Average		126.7	69.3	196.0	3%	64.6%
Notes: Estimates based on Cadmus analysis of AMI interval consumption data for participant facilities. Percentage demand savings were estimated as the ratio of the estimated demand savings to estimated baseline demand.						

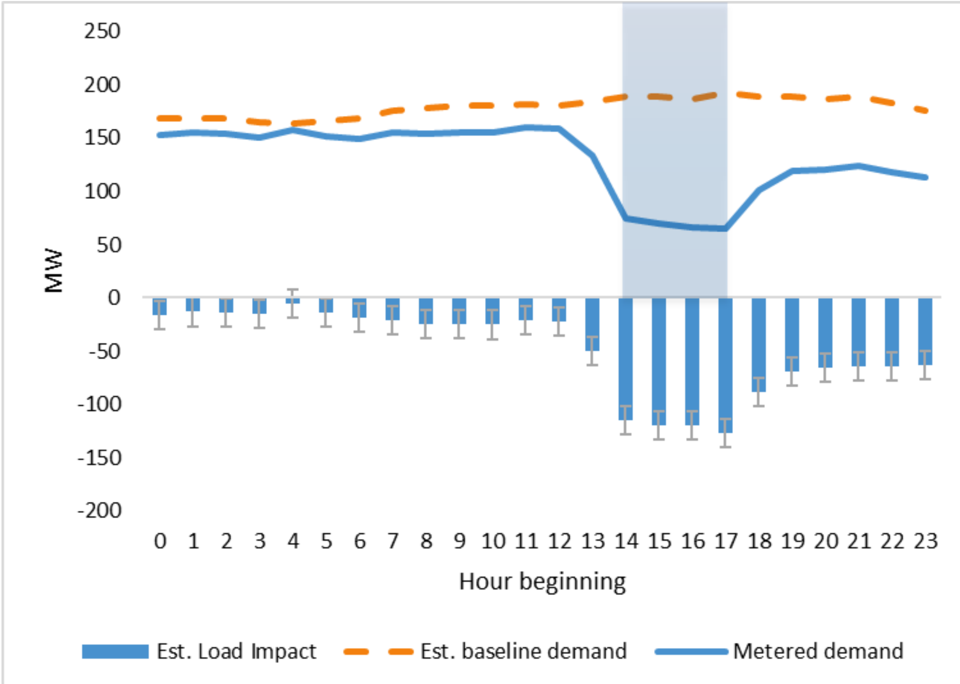
Across event hours, the program saved about 65% of participant electricity demand during event hours. Large C&I customers saved significantly more demand as a percentage of the baseline (about 70%) than small C&I customers (about 15%) and GNE customers (about 25%).

Load Impacts by Event Day

Figure A-10, Figure A-11, and Figure A-12 present metered demand, the estimated baseline demand, and the estimated load impacts of participant facilities by hour of the day for the three Act 129 demand response event days. The error bars for the load impacts show 90% confidence intervals. The event window is shaded.

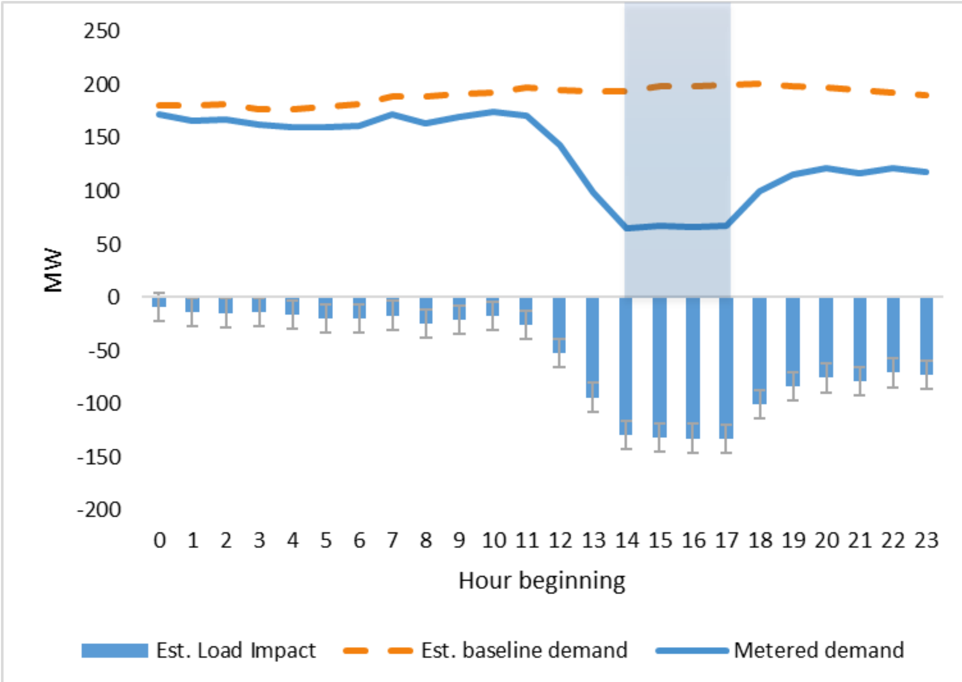
On June 13, 2017, electricity demand of participants was slightly below the expected level, as shown by metered demand lying below baseline demand before the event. Only some of these differences are statistically significant, however, as shown by the 90% confidence intervals for the load impacts that include zero. Below, Cadmus presents evidence that several facilities with large demand response capacity (>5 MW) reduced their loads below normal on the day before the event. This load reduction on June 12, 2017 may have carried over into the event day. After the event ended, energy demand remained below normal through the end of the day.

Figure A-10. June 13, 2017 – Hourly Load Impacts



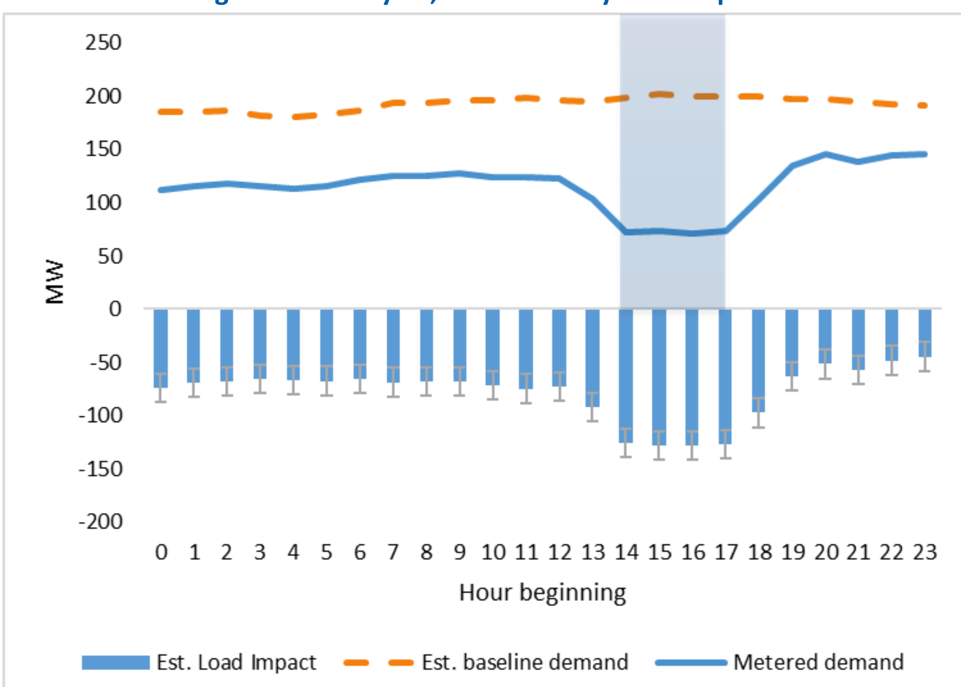
The load impacts on July 20 appear like those on July 13. Demand was slightly below normal before the start of the event and did not return to normal after the event ended before the end of the day. Demand remained below normal because during the late morning or early afternoon of July 20, participants received notification that another Act 129 event would occur on the following day. Many large C&I participants did not resume normal consumption of utility-supplied electricity.

Figure A-11. July 20, 2017 – Hourly Load Impacts



In the early morning of July 21, demand of Act 129 participants was over 33% below the expected level. After the event ended, demand increased but did not return to normal levels before the end of the day.

Figure A-12. July 21, 2017 – Hourly Load Impacts



Overall, these results suggest that Act 129 demand response events produced significant effects on electricity consumption during non-event hours on event days. Energy consumption was below normal during event and non-event hours, resulting in savings of utility-supplied electricity. Some participants reported that they maintained business operations during events by substituting on-site backup generation for utility-supplied electricity, while others reported curtailing operations, reducing electricity consumption, and shifting loads to non-event hours and days.

Event Day Load Impacts by Customer Segment

Figure A-13 through Figure A-20 show the load impacts by hour of each event day for GNE, large C&I, and small C&I participant customers. There was only one small C&I customer that participated in the July 20, 2017 event, and no small C&I customers participated in the July 21, 2017 event.

In the GNE and small C&I customer segments, some customers appear to have shifted loads from event hours to non-event hours. This load shifting is manifested as higher than normal demand in hours before and after events. GNE and small C&I customers could shift air conditioning loads by cooling their facilities to a lower temperature before the start of the event. Day-ahead notification of Act 129 events allowed participants to manage their loads. After the events ended, electricity consumption snapped back, as the energy management system returned the facility's interior temperature to normal settings.

Figure A-13. June 13, 2017 – GNE Participants

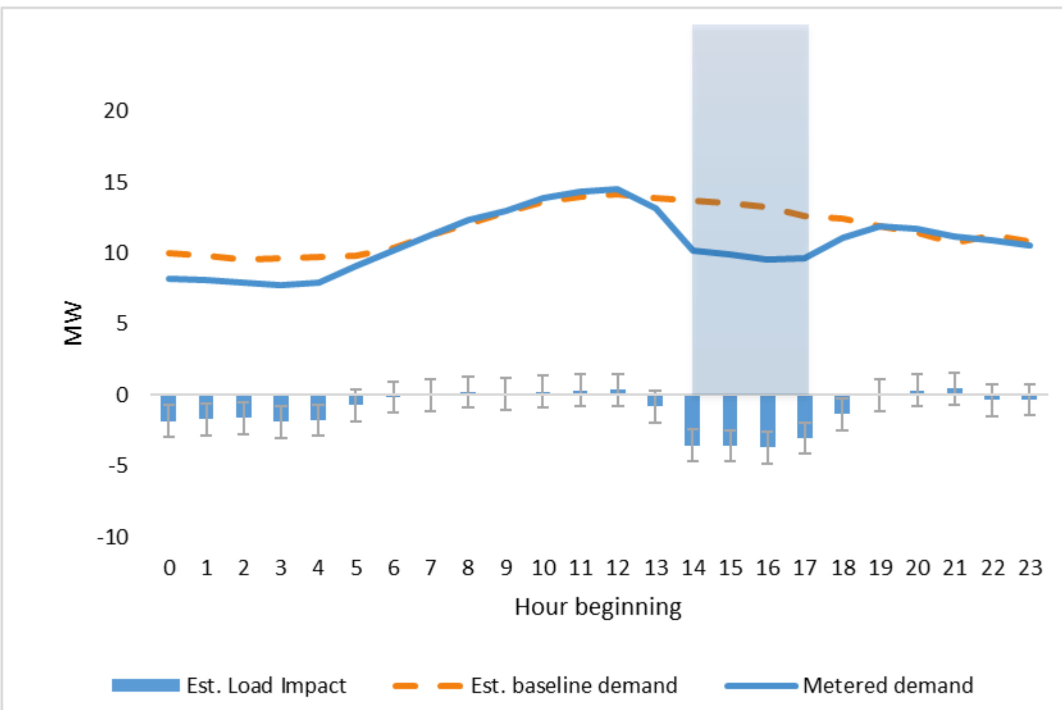


Figure A-14. July 20, 2017 – GNE Participants

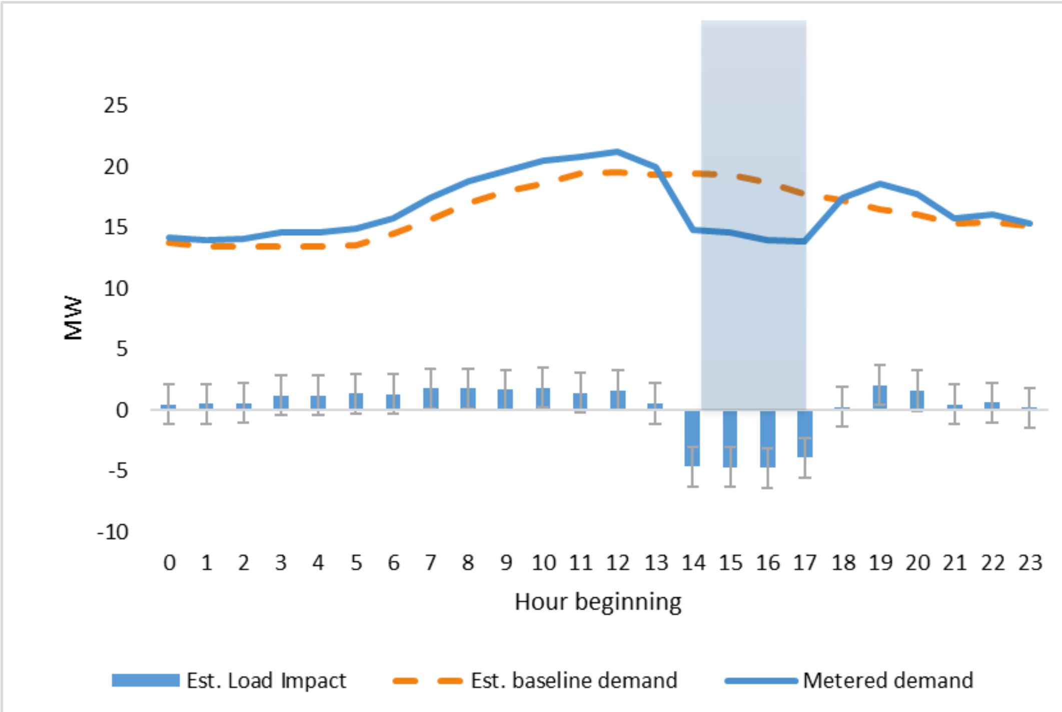


Figure A-15. July 21, 2017 – GNE Participants

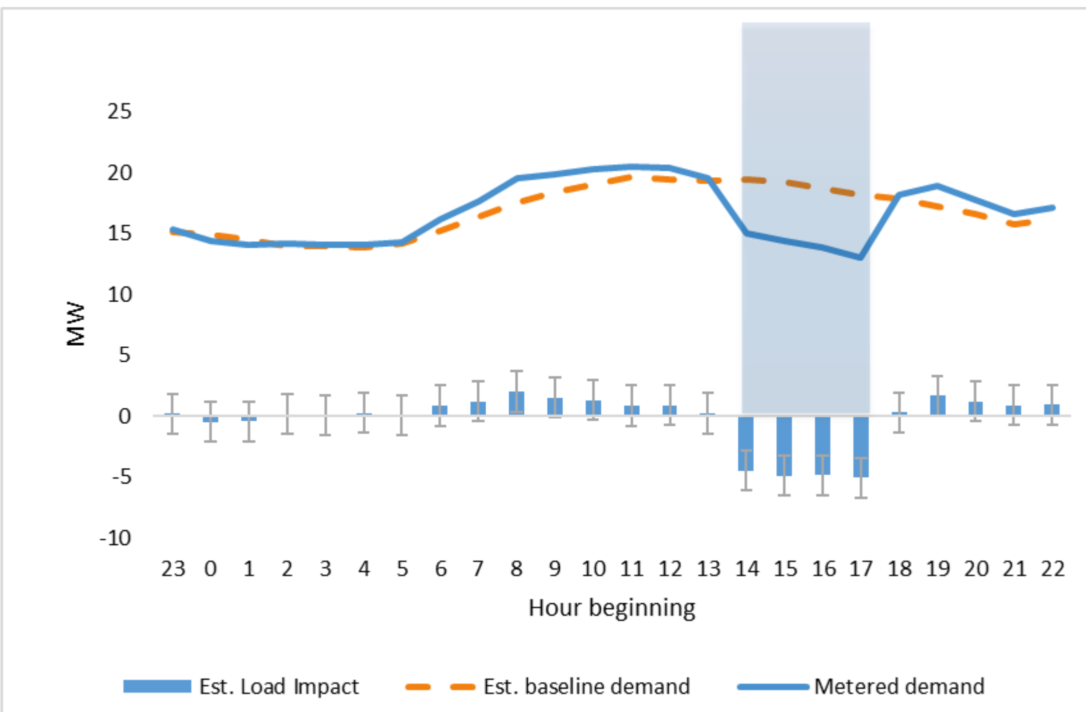


Figure A-16 through Figure A-18 show load impacts for large C&I participants. Since these participants accounted for 95% of the event demand savings, Figure A-16 through Figure A-18 look very much like

Figure A-13 through Figure A-15. As expected, the loads of large C&I customers do not appear very weather-sensitive. Loads only trended up slightly across hours of the day.

Figure A-16. June 13, 2017 – Large C&I Participants

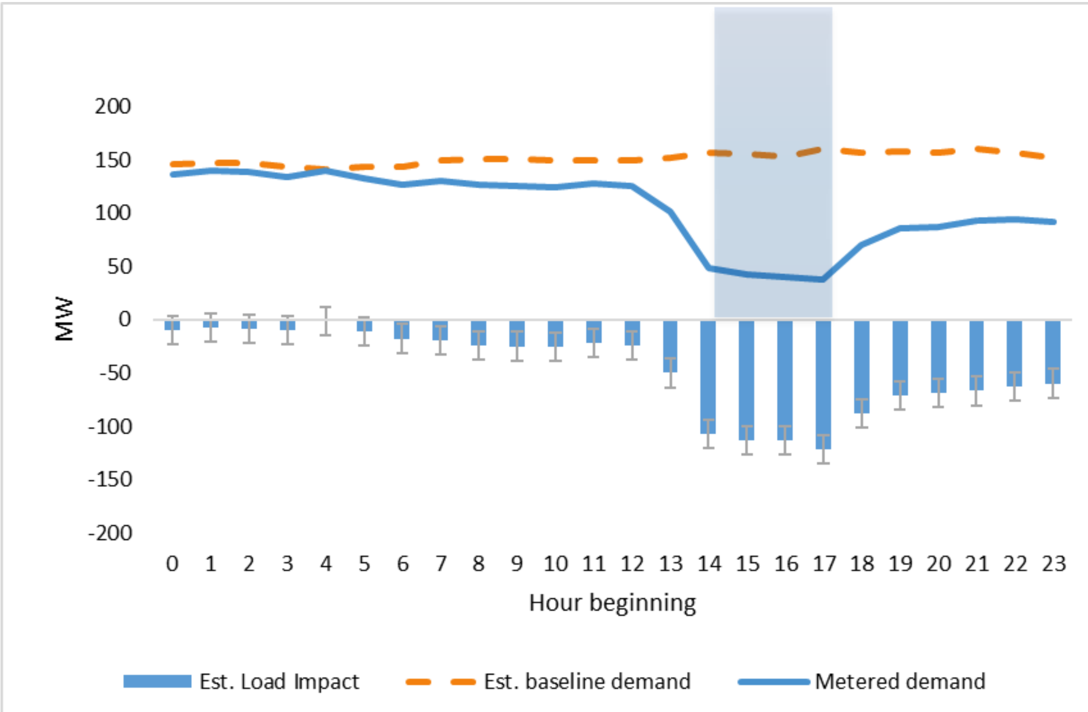


Figure A-17. July 20, 2017 – Large C&I Participants

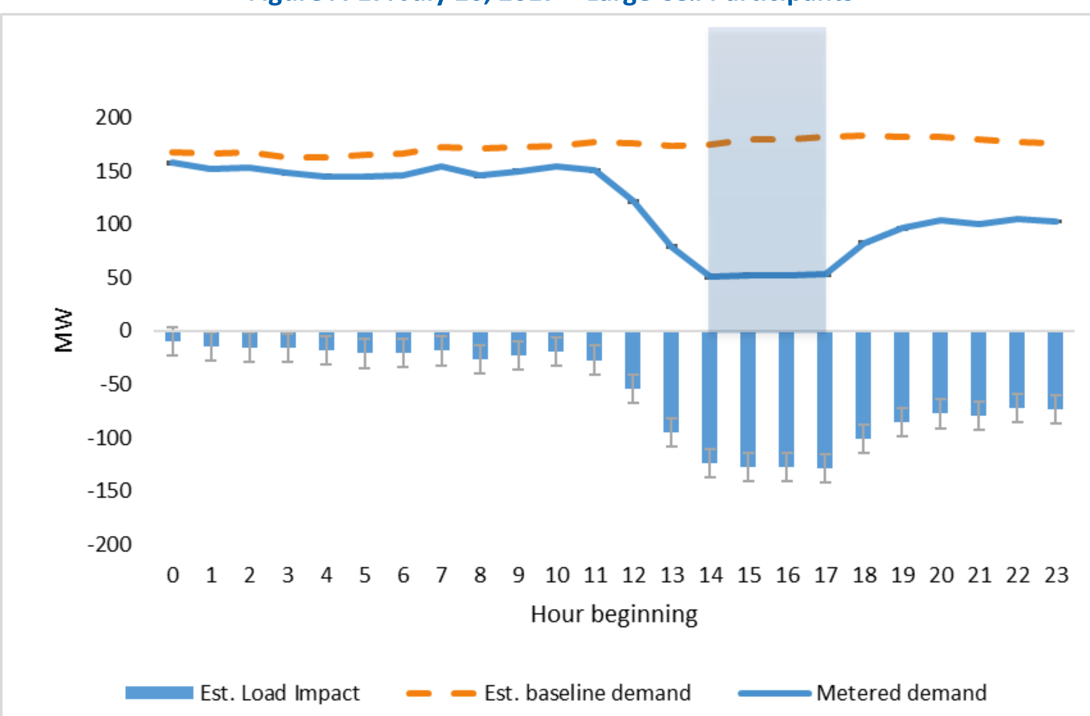


Figure A-18. July 21, 2017 – Large C&I Participants

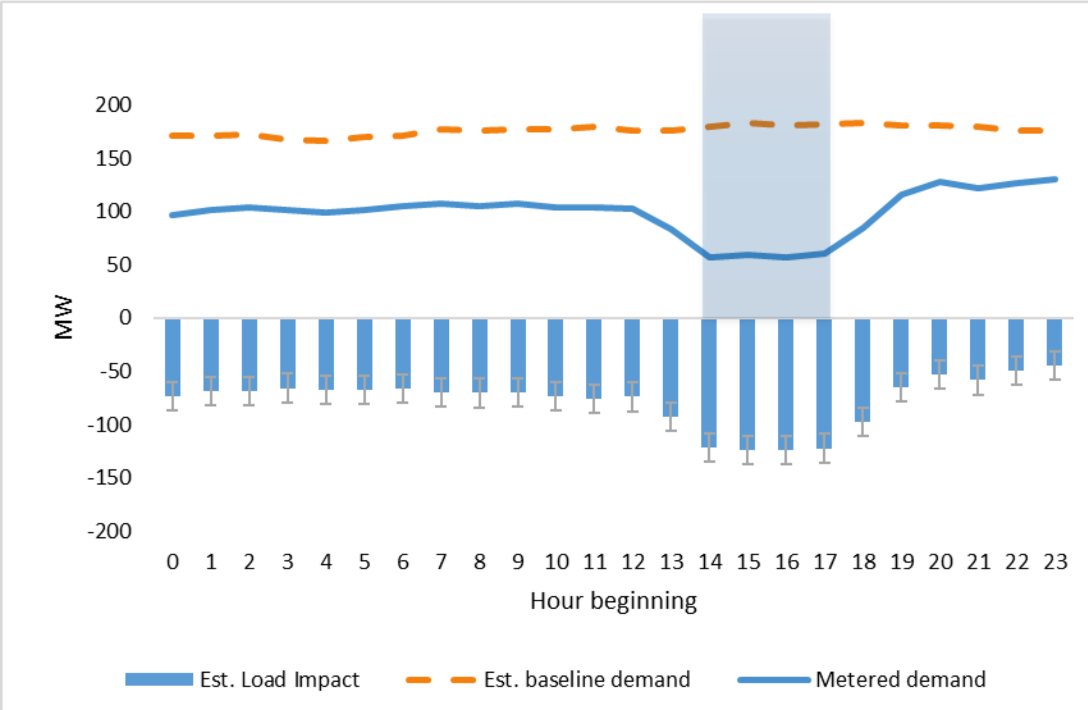


Figure A-19 and Figure A-20 show the load impacts for small C&I customers on June 13 and July 20. As noted above, only one small C&I customer participated in the July 20 event. Both figures show that electricity consumption rebounded significantly after the event ended.

Figure A-19. June 13, 2017 – Small C&I Participants

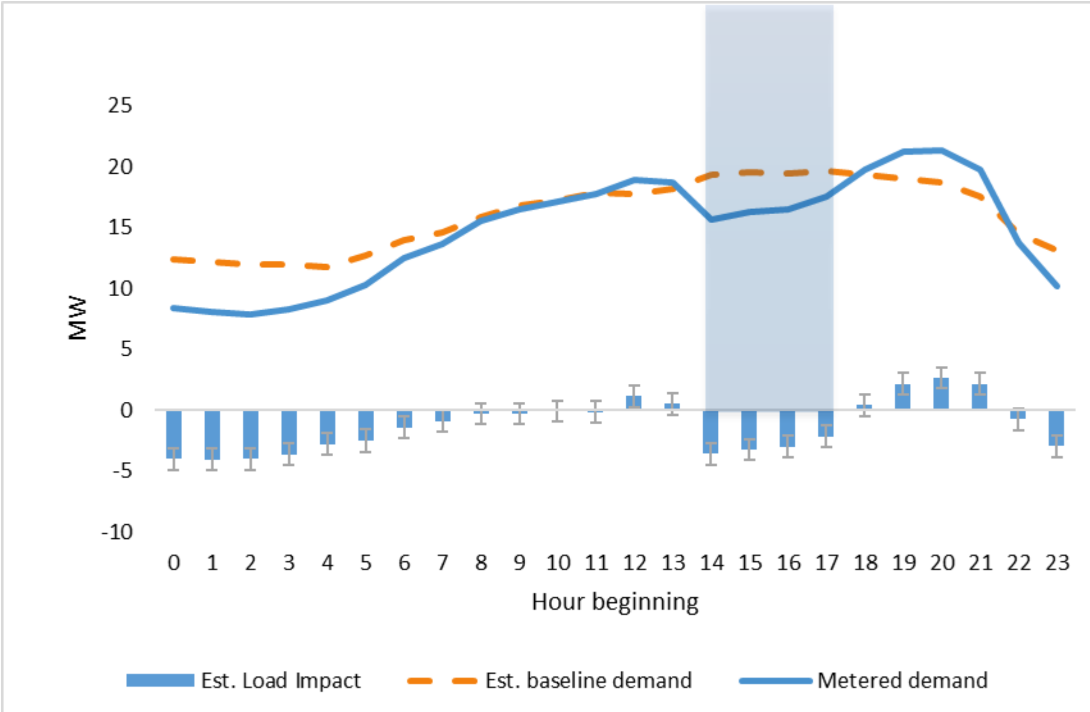
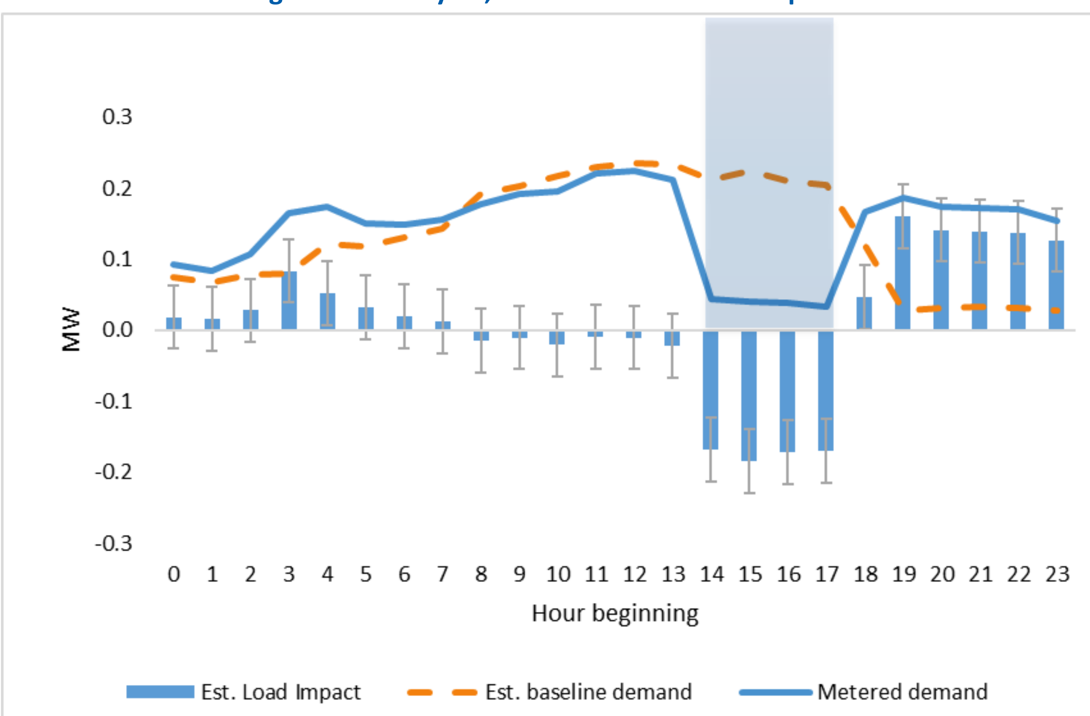


Figure A-20. July 20, 2017 – Small C&I Participants



Analysis of Notification Day Load Impacts

Cadmus also analyzed the load impacts of event notifications on notification days. The analysis shows that consumption of many large C&I participant facilities on notification days was outside the normal range, suggesting that they adjusted their loads in response to either event notifications or other factors. The Evaluation Framework for Pennsylvania Act 129 Phase III Programs gave evaluators discretion about whether to include notification days in the basis window. Since electricity consumption on notification days was outside the normal or expected range for many participant facilities, Cadmus decided not to include these days in the basis window. This analysis supports our decision to exclude event notification days and partially explains the difference in the reported and evaluated savings.

As Table A-7 indicates, participants received advance notifications of Act 129 events in the morning or early afternoon of the preceding day. There were three events, but since the July 20 and July 21 events occurred on consecutive days, the event notification for July 21 was given on an event day, and any load impacts of the event notification would be confounded with those from the event. For the June 12 and July 19 notification days, Cadmus estimated facility baseline consumption and compared it to metered consumption in the hours after customers received the event notification. It looked for changes in energy demand that suggested the facility adjusted its consumption in response to the event notification or that were otherwise unexpected. Cadmus focused the analysis on the 17 facilities that contracted to supply at least one MW of demand response capacity.

First, several facilities, including two supplying well over 5 MW of demand response capacity, appear to have ramped up or down their consumption shortly before or after receiving event notifications on June 12, 2017. Figure A-21 through Figure A-26 show load impacts on notification days for different facilities supplying at least 1 MW of capacity. The shaded areas show post-event notification hours. Cadmus removed the y-axis labels to protect the confidentiality of the participants since the consumption could be used to identify them. The dotted lines show the 90% confidence intervals for the estimated baselines. When metered consumption lies outside the confidence interval, it suggests that facility's demand was not in the expected range.

Figure A-21. Illustration of June 12 Notification Day Impacts for Large C&I Participant Facility

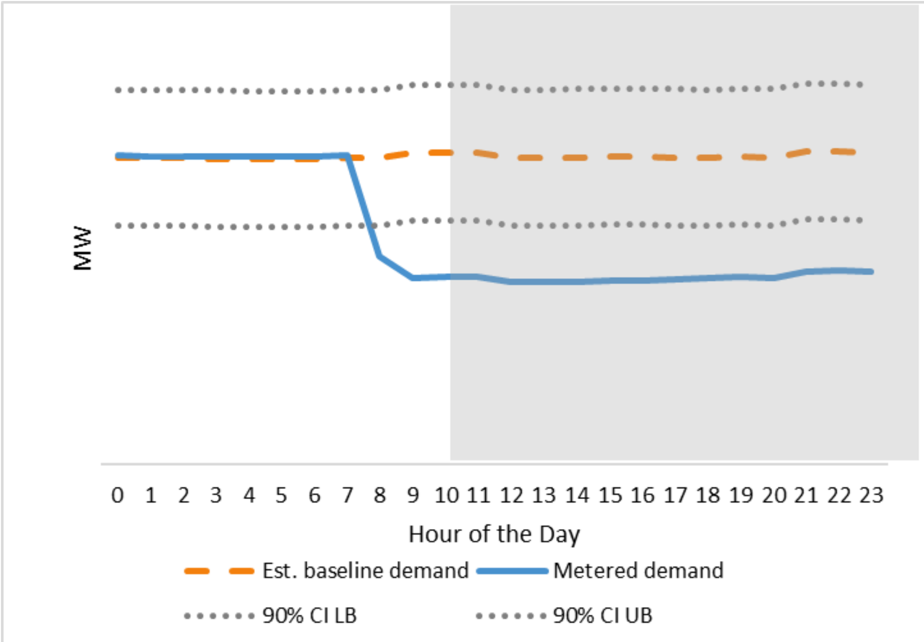


Figure A-22. Illustration of June 12 Notification Day Impacts for Large C&I Participant Facility

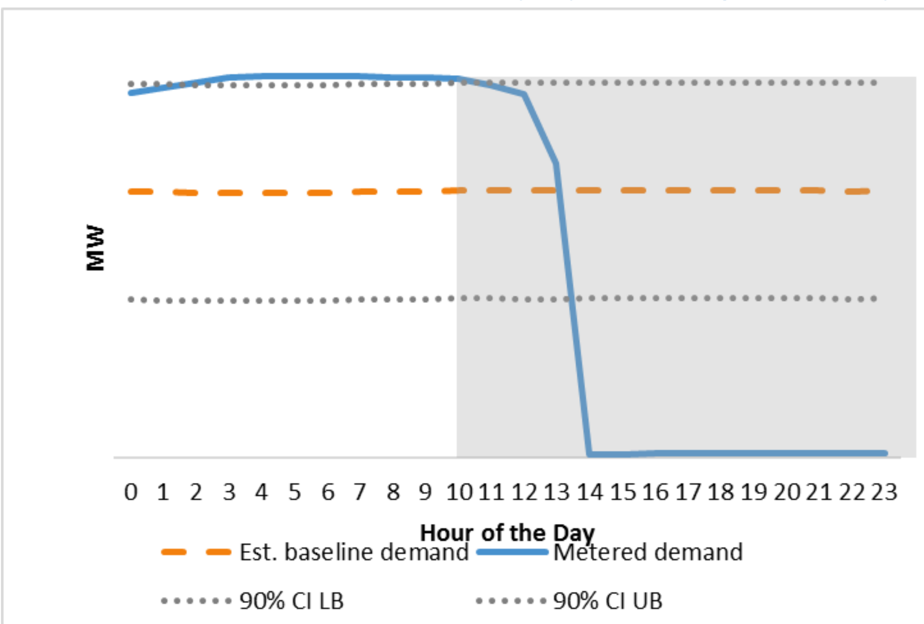
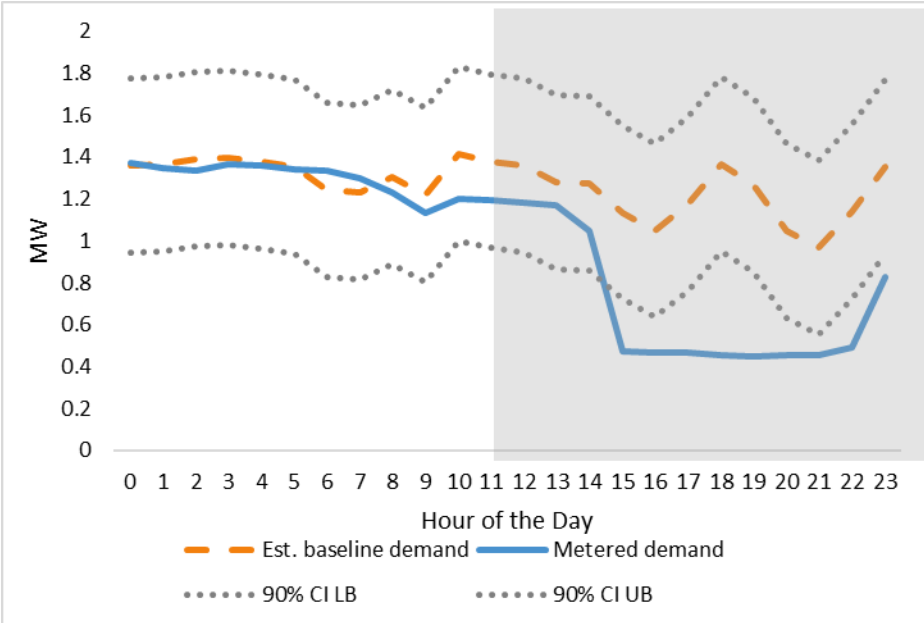


Figure A-23. Illustration of July 19 Notification Day Impacts for Large C&I Participant Facility



In addition, several facilities appear to have curtailed loads on event notification days as if an event was scheduled for the notification day. This includes one facility that enrolled more than 5 MW of demand response capacity. According to ICSP's records, this facility did not participate in the PJM economic market on this day.

Another potential explanation for these notification day impacts is that on June 12 and July 19, the PJM region experienced two of five coincident peaks (5CP) in 2017, which are days between June 1 and September 30 with the five highest daily unrestricted RTO peak loads. EDCs calculate customer peak load contributions and demand charges based on customer consumption during these hours. It is possible some customers attempted to manage their loads on these days to reduce their peak demand charges.

Figure A-24. Illustration of July 19 Notification Day Impacts for Participant Facility

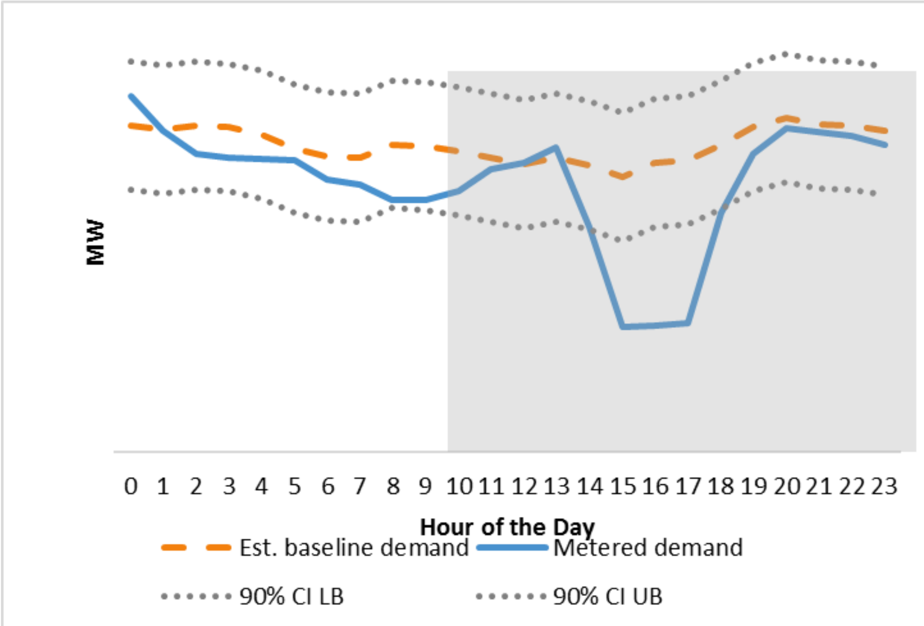


Figure A-25. Illustration of July 19 Notification Day Impacts for Participant Facility

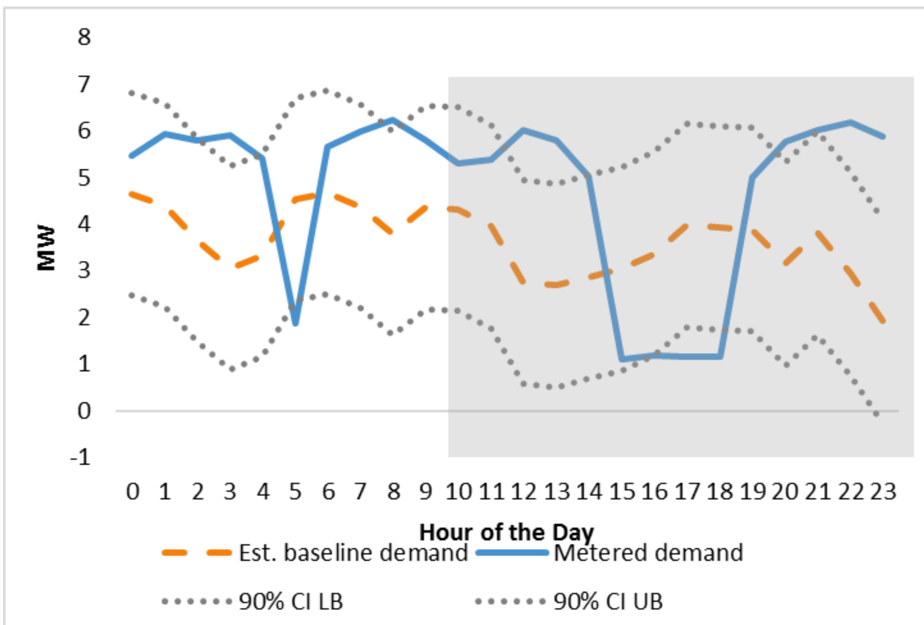
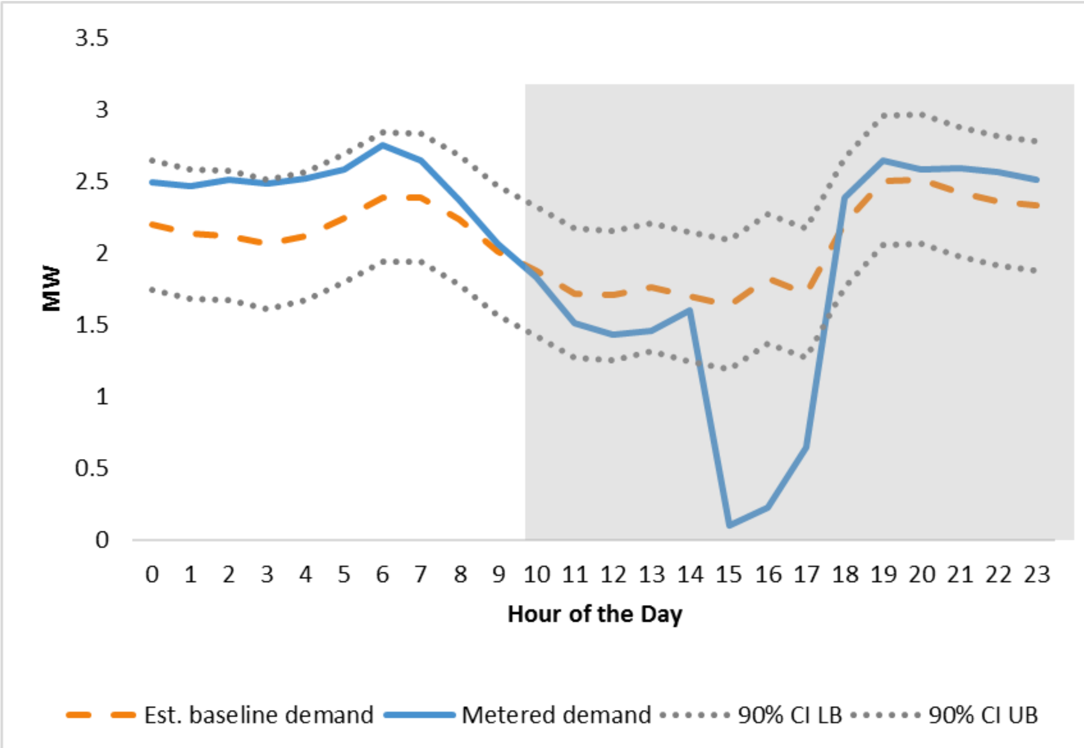


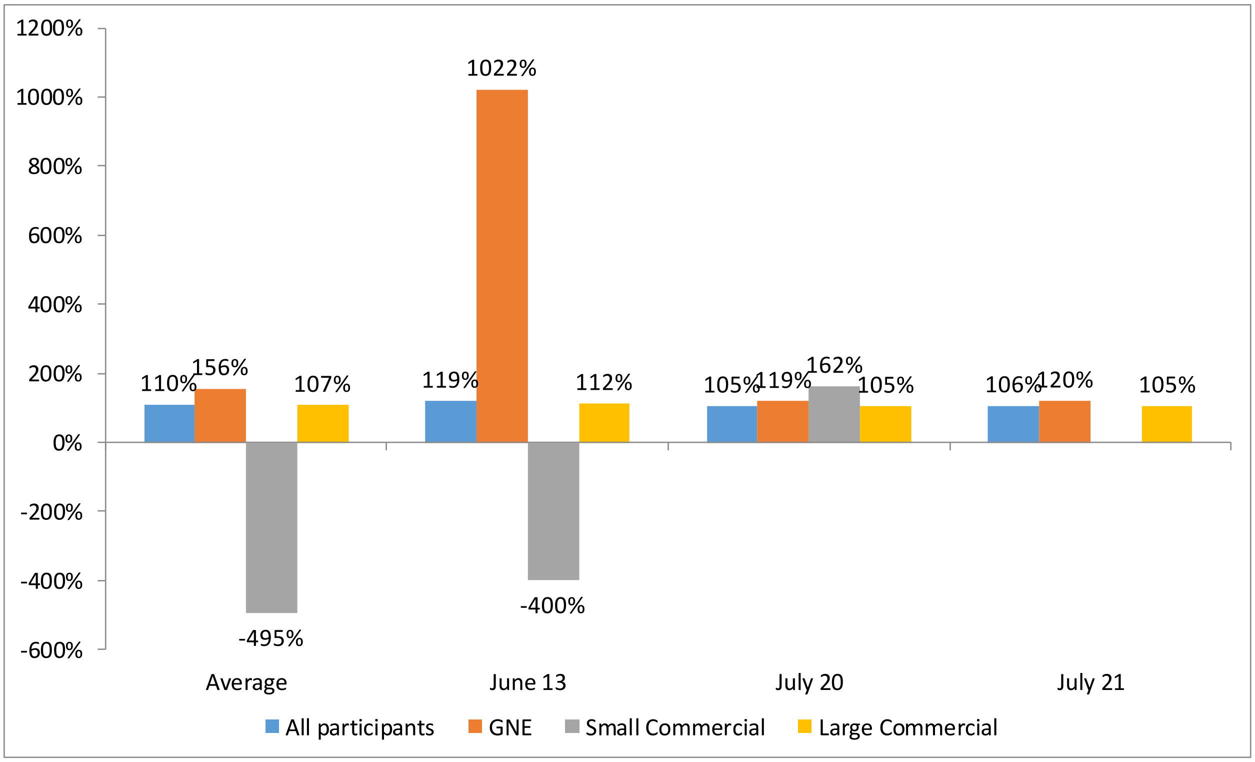
Figure A-26. Illustration of July 19 Notification Day Impacts for Participant Facility



A.2 Realization Rate Findings

Figure A-27 shows the savings realization rate—the ratio of gross verified to gross reported savings—for each Act 129 event and the average across events. The realization rates ranged from 105% for the July 20 event to 119% for the June 13 event. Across all events, the savings realization rate was 110%. The biggest discrepancies between gross reported and verified savings occurred for GNE and small commercial participants. For the June 13 event, Cadmus estimated savings of 3.1 MW for small C&I participants while the ICSP estimated savings of -0.7 MW. Similarly, for the same event, Cadmus estimated savings of 3.5 MW for GNE participants while the ICSP estimated savings of 0.3 MW.

Figure A-27. Event Savings Realization Rates



Note: Realization rates estimated based on Cadmus analysis of AMI interval consumption data for participant facilities and ICSP reported demand savings.

For the June 13 event, Cadmus estimated savings approximately 20% higher than the ICSP (CPower) for two reasons. First, as noted above, the day matching estimator that the ICSP used for the GNE and small C&I facilities substantially underpredicted baseline demand and therefore demand savings during events. Second, Cadmus excluded event notification days from the basis window while the ICSP did not. As shown above, several large C&I facilities with large enrolled capacity may have reduced their consumption in response to the June 12 event notification. Including notification days has the effect of reducing the estimated baseline and savings.

A.3 Process Evaluation

The process evaluation assessed program processes to provide possible recommendations for improving program operation. Cadmus' process evaluation for the Demand Response Program assessed participant motivation, participant satisfaction, challenges and processes that worked well.

A.3.1 Process Evaluation Methodology

To accomplish these objectives, Cadmus interviewed PPL Electric Utilities and ICSP program staff, conducted participant interviews, reviewed program materials, and reviewed the program logic model.

Program Staff and ICSP Interviews

In November of 2017, Cadmus conducted interviews with the program managers from PPL Electric Utilities and the ICSP. The interviews focused on the following:

- Gathering insights into program design and delivery
- Identifying areas working well (successes)
- Identifying areas that could be improved (challenges)
- Assessing perceived customer experience including satisfaction

Participant Interviews

Cadmus conducted telephone interviews with participating customers between November and December of 2017. The interviews focused on:

- Program satisfaction
- Motivations for participating in the program and perceived benefits and costs
- Satisfaction with event advance notification and feedback about achieved load reductions
- Abilities and strategies for shifting of loads from event to non-event hours
- Recommendations for program improvements and other process issues
- Program processes that are working well

To prepare the interview contact list, Cadmus included all 93 facilities participating in the PY9 Demand Response Program. Because seven participating companies managed multiple facilities, including 63 retail facilities managed by just 3 companies, Cadmus created a contact list of 26 unique participating companies. This contact list ensured that there was no personnel overlap between individuals we contacted. Cadmus considered participating companies that were co-owned and represented by a single energy manager, as a single company.

Because the top 10 customers, ranked by enrolled MW load reduction, accounted for 91% of the program's total load reduction, Cadmus prioritized interviewing these top 10 customers, followed by customers with an enrolled load reduction of 1 MW or more, and lastly all remaining customers.

Table A-9. Process Evaluation Sampling Strategy

Enrolled Demand Reduction (MW)	Percentage of Contracted MW	Number of Unique Participating Companies	Number Contacted	Number Achieved
128.5	91%	10	10	3
8.4	6%	7	7	5
4.9	3%	9	9	2

Following an introductory email from the ICSP, Cadmus contacted and requested an interview with the individual responsible for managing participating facilities' load reduction during Act 129 events and for enrolling the company as a Demand Response Program participant. For situations where these responsibilities were shared by multiple individuals, Cadmus reached out to all parties. Despite multiple attempts to contact high priority participants via email and phone calls, and considerable staff flexibility scheduling interviews, Cadmus completed interviews with 3 of the top 10 participants. Although Cadmus met the evaluation target of 10 participant interviews, none of the top five participants agreed to an interview, which limited the representative enrolled MW of interview respondents to 12.4% of the total enrolled MW in the program.

Table A-10 shows the total participant population size and the response rate as a percentage of unique participants.

Table A-10. Participant Interview Sampling Plan and Response Rate

Survey Mode and Audience	Population	Participating Companies	Target Sample Size	Achieved Sample Size	Response Rate
Participant Telephone Interviews	**93 facilities**	**26 companies**	10	**10**	**38%**

See Section *A.3.3 Sample Cleaning and Attrition for Participant Interviews* for sampling cleaning and attrition.

A.3.2 Additional Findings

This section presents additional findings from the participant interviews.

Program Delivery

The Demand Response Program is designed to reduce PPL Electric Utilities' system load by an average of 92 MW as mandated by the PaPUC's Act 129 requirements. Participants were primarily recruited through the ICSP's existing customer base and through targeted outreach to other large customers in PPL Electric Utilities' service territory. To ensure that the minimum load reduction threshold was met during the first performance year, the ICSP over-subscribed the program, resulting in between 110 MW and 130 MW reduction per event.

From June to September 2017, the ICSP identified three program events during which PPL Electric Utilities' projected peak system load was expected to meet or exceed 96% of total capacity for at least one hour. Events were identified at 9:45 a.m. the day before and were scheduled to last four consecutive hours, which were selected by the ICSP. Events were limited to non-holiday weekdays, two of which were scheduled consecutively.

By 10:30 a.m. on the day prior to the event, the ICSP provided advance notice to PPL Electric Utilities and PJM followed by email, text, and phone notifications to program participants. Participants were encouraged to enroll by 3:00 p.m. of the day prior to the event but could choose to enroll up to the event start time. Participants could also choose to enroll for a portion of the four-hour event. To enroll in an event, participants selected specific hours for enrollment on the ICSP's online platform. On the day of the event, the ICSP sent a reminder to enrolled participants and a final notification to unenrolled program participants and actively managed participants to optimize peak reductions for the event. Load reductions were estimated in real time using the ICSP's online platform. After the event, the ICSP and PPL Electric Utilities reviewed event performance and data.

Logic Model Review

Cadmus reviewed the Demand Response Program's logic model and determined this program is operating as expected. Table A-11 summarizes the outcome of the logic model review.

Table A-11. Demand Response Program Logic Model Review

Expected PY9 Outcome	Logic Model Element	Actual PY9 Outcome
ICSP recruits eligible C&I customers, identifies event days and sends notifications, estimates peak reductions for each participant, prepares to process incentives	**Program Activities**	Program activities conducted as planned
ICSP successfully recruits customers, customers enroll in events, and incentives paid	**Outputs Produced by Program Activities**	Delivered most outputs as expected in PY9; incentive payments delayed
Act 129 demand reduction requirements met	**Short-term Outcomes**	Produced short-term outcomes (PY9)
Proven reliability of the Demand Response Program to deliver demand reductions, compliance with the PaPUC's Act 129 demand response rules	**Intermediate Outcomes (second and third program year)**	On track to produce intermediate outcomes
PPL Electric Utilities meets the PaPUC's Act 129 DR requirements, customers are satisfied with the program and with PPL	**Long-term Outcomes (end of Phase III)**	On track to produce long-term outcomes

Participant Profile

Most participating companies (16 of 26) in PPL Electric Utilities' Demand Response Program are large C&I customers with the remaining participation equally divided between small C&I and GNE customers (Table A-12). Manufacturing, the predominant participant industry, contributes roughly 94% of the total load reduction, followed by the retail industry. Event load reduction is largely driven by a select few participants—the top five participants, ranked by enrolled MW load reduction, represent 74% of the total enrolled MW, and the top 10 participants represent 92%.

Table A-12. Participant and Respondent Profile

Sector	Unique Participating Companies	Interview Respondents
Large C&I	16	6
Small C&I	5	3
GNE	5	1
Total	**26**	**10**

Participant Satisfaction

Respondents were satisfied with the program ICSP, with 3 respondents reporting that they were *very satisfied* and 5 reporting that they were *somewhat satisfied* with their interactions with the ICSP.

Considering that all program participants (all 93 participating facilities) have also participated in at least one other demand response program (PJM), including two respondents who participate in multiple demand response programs throughout the country, respondents voluntarily compared PPL Electric Utilities' program to these other programs during the interviews. Respondents predominantly indicated that, although the Act 129 program requirements are stricter than PJM's, PPL Electric Utilities' Act 129 program incorporates several design advantages, such as the timing of notifications and the frequency of events, which contributes to their overall satisfaction with the program.

Communications

Cadmus asked respondents if they had received feedback from the ICSP regarding their achieved load reduction and seven of nine said they had. Of the respondents who did receive feedback, six of seven said the feedback they received about their load reduction was useful, but all six said the feedback did not affect how they curtailed their load during the following events. For one customer, feedback from the ICSP alerted them to an issue in the facility's automated load reduction system, and subsequent communications helped to identify the specific issue. Of the two respondents who had not received feedback, one was unaware that the company had been removed from the called-upon participant list because of poor load reduction performance during the first event.

Respondents were satisfied with their communications with ICSP – four respondents said that they were *very satisfied,* and four respondents said that they were *somewhat satisfied.* The remaining two respondents said they were *not too satisfied* with their communications with the ICSP. One participant said there was no communication after the event ended; this participant tried reaching out to the ICSP to discuss the facility's performance but was unable to reach them it after multiple attempts. Another participant said the ICSP's communication was too "automated and impersonal" compared to a different CSP the participant had worked with.

Cadmus asked respondents to provide suggestions to improve communications with the program ICSP. The majority (7) of respondents did not provide any suggestions for improving communication. One participant (n=10) would appreciate more upfront training on how to use the ICSP's online platform, and two participants requested more frequent and more detailed feedback from the ICSP about their performance. The lower satisfaction ratings for communications with the program ICSP were provided by participants with enrolled MW load reduction <1 MW.

Participant Motivation

Cadmus asked respondents to identify the factors that motivated their participation in the program. All 10 respondents said the program incentive was the primary reason for participating. Three participants also said that, because they participate in PJM's demand response program, they already had the internal protocols in place for load reduction and that signing up for and participating in PPL Electric Utilities' Act 129 events was easy and made sense financially. One respondent said that because the probability of Act 129 events occurring was higher than PJM events, enrolling in both programs increased the likely incentive payments for a single season. Two customers who shed load, rather than shifting to backup generators, also said the benefit of reducing their electric bill was a factor in their decision to participate. One participant said that participating in the Act 129 program helped them lower the baseline kWh price they pay their CSP.

None of the respondents, regardless of load reduction strategy, said they had to be convinced to sign up; the program was viewed as financially and operationally attractive, even in comparison to participating in PJM's program.

Program Benefits and Costs

Incentives allow companies to recoup the opportunity costs incurred when normal business operations are curtailed. The largest expected incentive was roughly $60,000 for the group of participants interviewed, and $270,000 for all program participants. Two manufacturing customers who were interviewed expressed the greatest concern over the delayed incentive payment, as did one other participant that enrolled a large amount of megawatts for event load reduction.

Nine of 10 respondents said that they will likely participate in the Demand Response Program in 2018. One respondent who was unlikely to participate said that generator fuel costs and the internal labor needed for participation outweighed the incentives. Nevertheless, this participant said the facility would continue participating in PJM's program because the incentives were higher. Another respondent was concerned about how the program affected the facility's calculated Peak Load Contribution (PLC) value for PJM's program, and as long as the PLC value was not negatively affected, this participant planned to continue participation in PPL Electric Utilities' program.

Event Notification

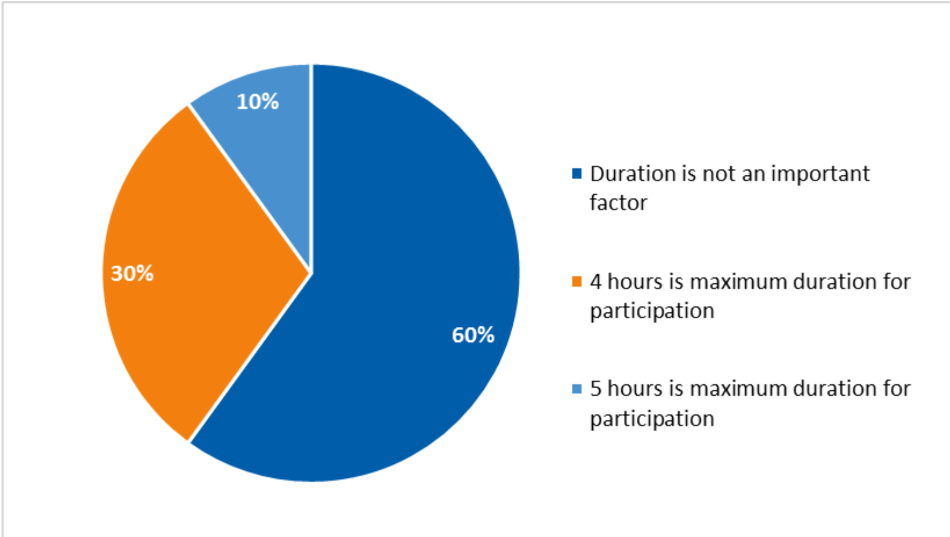
All 10 respondents said that the timing of event notifications was adequate for them to prepare for an event. For comparison, PJM events can be called with as few as 30 minutes of advance notification. Five of the respondents said they could respond to an event with an hour or less of advance notification and three said four hours or less was adequate. Two said they needed 24 hours advanced notice; these were also the two largest participants interviewed in terms of enrolled megawatts.

Two respondents said that, even if they could accommodate less than 24 hours' notice, they appreciated as much advance notice as possible, particularly if events were called back-to-back, so they could plan the facility's production schedule around the event hours and incorporate all necessary components of their load reduction plan to hit their reduction target.

Event Duration and Frequency

Respondents did not view the duration or frequency of events as major challenges—all 10 respondents said that the duration and frequency of the events did not affect their ability to participate. Seven of 10 were capable of participating in events longer than four hours (Figure A-28). Of all 26 participating companies, three enrolled for the partial duration of an event, and one of these cited a generator issue as the reason for partial participation.

Figure A-28. Maximum Event Duration



Source: Interview question B5, "How, if at all, did the duration and frequency of events affect your ability to participate?" (n=10)

Generally, respondents said that, although participating in events on two or more consecutive days was challenging, they could meet their load reduction target given enough advance warning (24 hours). Nevertheless, some respondents voiced concern about their ability to reliably perform during consecutive events. One respondent was highly dependent on having the right personnel present for an event, and that back-to-back events were more likely to coincide with critical personnel absences. Another respondent said that fluctuating production requirements could dictate the facility's ability to participate in consecutive events. All respondents dispatched by the ICSP for the back-to-back events in July did participate in both events.

Nine of 10 respondents also said they would probably participate in events called four days in a row if given sufficient notice. However, their definition of sufficient notice changed for four consecutive events. Seven of 10 customers would participate in events called four days in a row if the current notification schedule (24 hours notice) was used. Generally, respondents said that as the number of possible consecutive event days increases, the need for more advanced notification becomes more pronounced.

Respondents who reduced load through automated systems that do not affect business operations did not hesitate about participating in consecutive events. Two of these respondents had prior demand response experience in other markets with programs that frequently called events three or more days in a row; they said they would be well-equipped to participate in consecutive events called for PPL Electric Utilities' Demand Response Program. However, respondents who had to shut down business operations during events were generally more hesitant to commit to participate in multiple consecutive events.

Load Reduction

Respondents use a variety of strategies to reduce their load during events, ranging from simple automatic light dimming and HVAC cycling to the complex process of shutting down melting furnaces and kilns. Strategies fall into three main categories (Table A-13). Five of the respondents said it was difficult to meet the expected load reduction threshold, and these respondents were represented within all three types of load reduction strategies. Reported difficulties included generator issues and the high cost of restarting certain equipment when an event was called during a production cycle.

Table A-13. Load Reduction Strategies

How Load is Reduced	Number of Respondents
Shift (generator)	3
Shed with same business functionality	3
Shed with reduced business functionality	4
Source: Interview question, “What did your facility do to reduce or shift its load?”	

Participants did not report any significant pre-event ramp-up or post-event snap-back load effects. Only one respondent reported taking any specific actions to prepare for the event; the action involved pre-chilling the air-conditioned space the night before an event. After an event, four respondents restarted equipment shut off during the events, two restored HVAC or production equipment to normal temperature settings, and four respondents took no specific load-modifying action other than cycling off generators or resuming business operations.

None of the respondents thought they could significantly reduce load further during a single event, but some offered ideas for additional, but minimal, load reduction (Table A-14). No respondents indicated any willingness to pursue any of these opportunities.

Table A-14. Further Load Reduction Opportunities

Possible Ideas to Reduce Load	Number of Responses
Install higher HVAC equipment	3
Use a generator to shift load	1
Change hours of business activities	1
Shift to dimmable LEDs	1
Shift small lighting loads and reduce battery charging	1
Source: Interview question C4, “Do you think that your facility could reduce load further during a single event?” (n=7, multiple responses allowed)	

Program Strengths

Cadmus asked respondents to identify specific aspects of the Demand Response Program that worked well. In general, respondents reported that the program performed as expected and that the 24-hour event notification and the online platform were key strengths of the program (Table A-15).

Table A-15. Demand Response Program Strengths

Aspects Working Well	Number of Responses
24-hour notification	3
Everything functioned as intended	3
Online platform	2
Program easy to understand	1
Good number of events	1
Act 129 worked well with established protocol	1
Source: Interview question D5, "Again, thinking about the program, what aspect of the program worked particularly well?" and other comments provided throughout the interview. (n=10; multiple responses allowed)	

Suggested Program Improvements

Cadmus asked respondents for recommendations to improve the program. In general, respondents said the program worked well as is and there is minimal room for improvement. Nevertheless, respondents identified a few specific areas that could be improved during next year's program. Three respondents said the ICSP should improve the timing of incentive payments and make it more comparable to PJM's payment policy. One respondent said the payment procedure should be clearly explained prior to participating. Other suggestions included requests for additional training on how to use the online platform and having the ICSP fix the "Historical Usage" and "Financial Data" pages on the platform.

Two respondents were also concerned with how the program would affect their PLC value. They were unaware that they could discuss PLC baseline adjustments to account for load reduction during Act 129 events with the ICSP.

A.3.3 Sample Cleaning and Attrition for Participant Interviews

To prepare the contact list, Cadmus included all 26 unique participating companies in the PY9 Demand Response Program. See *Participant Interviews* section for a description of the contact list preparation.

Table A-16 lists total numbers of records contacted and the outcome (final disposition) of each record.

Table A-16. Demand Response Participant Interview Sample Attrition Table

Description of Telephone Call Outcomes	Count
Population (number of unique companies)	**26**
Removed: incomplete or bad phone number, inactive customer, completed survey in past 3 months, on "do not contact" list, opted out of survey, selected for a different survey, duplicate contact	**0**
Survey Sample Frame (used for telephone interview calls)	**26**
Not attempted	**0**
Records Attempted	**26**
Refusal	1
No answer/answering machine/phone busy/no response	15
Non-specific or specific callback scheduled	0
Partial complete (not included in survey findings analysis)	0
Completed Surveys	**10**
Response Rate (completed surveys divided by number of records attempted)	**38%**