Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

Pennsylvania Act 129

Phase IV Demand Response Potential Study

Prepared for the Pennsylvania Public Utility Commission
By Statewide Evaluation Team
February 2020

ACKNOWLEDGEMENTS

Principal Consultants

- Jesse Smith
- Alana Lemarchand

Senior Consultant

- Adriana Ciccone

Senior Quantitative Analysts

- Steve Morris
- Ross Beppler, PhD
- Mark Noll

This study was made possible by the efforts and cooperation of staff at the seven electric distribution companies highlighted in this report. Their assistance in providing the necessary data on customer segmentation, consumption, and contact information was instrumental in the design and execution of the study.

Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

PHASE IV DEMAND RESPONSE POTENTIAL STUDY

Pennsylvania's Statewide Evaluation Team performed an assessment of the DR potential for each of the seven largest distribution companies - PECO, PPL, Duquesne Light, Met-Ed, Penelec, Penn Power, and West Penn Power. This study also examines the costs and benefits of statewide policies to encourage the development and deployment of DR resources during Phase IV of Act 129.

- **Reduced potential compared to Phase III**
- **Heavily influenced by the decision to model DR as Peak Shaving Adjustments nominated to PJM**

No DR potential from the Large C&I sector because of prohibition of dual participation.

The DR trigger changes from a day-ahead load forecast to real time Temperature Humidity Index. This significantly reduces the positive effect of key DR driver #3 (Notification Time) shown in the figure below.

Key Drivers of DR Potential and Directional Effect

Incentive Payment ($/kW)

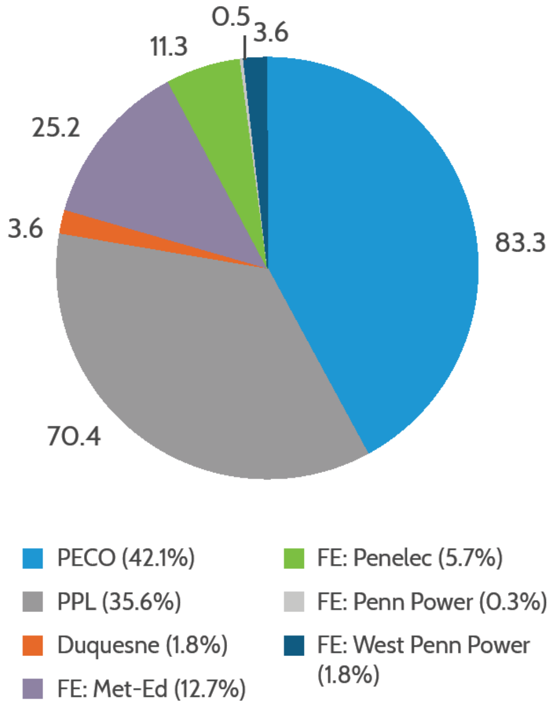
Frequency of Events

Notification Time

Duration of Events

DR Potential by EDC

(MW/year)



Levelized cost

$64.25/kW-year

(EDC budget requirement to acquire modeled DR potential)

EDC Phase IV budget requirement

5.2%

($63.58 Million of $1.22 Billion in statewide EE&C funding for the phase)

Statewide TRC

1.54

$86M of TRC benefits against $56M of TRC Cost. Cost-effective, but less so than Energy Efficiency.

Summary of Phase IV Demand Response Potential by Program

Connected thermostat	**Behavioral DR**	**Small C&I Load Curtailment**	**Behind the meter battery storage**
80.6 MW	55.2 MW	62.1 MW	0 MW

TABLE OF CONTENTS

Figures

Tables

1 EXECUTIVE SUMMARY

NMR Group, Inc. (NMR) and a team of subcontractors – collectively known as the Statewide Evaluation (SWE) Team – have been contracted by the Pennsylvania Public Utility Commission (PUC) to provide audit and planning consulting services for Phase III of the Commonwealth's Act 129 Energy Efficiency and Conservation (EE&C) programs. Part of the SWE Team's scope is to perform a demand response potential assessment for a possible Phase IV of Act 129 programs. The seven electric distribution companies (EDCs) subject to Act 129, and included as part of this study, are as follows:

- Duquesne Light Company (Duquesne or DLC)
- Metropolitan Edison Company (FE: Met-Ed or ME)
- Pennsylvania Electric Company (FE: Penelec or PN)
- Pennsylvania Power Company (FE: Penn Power or PP)
- West Penn Power Company (FE: West Penn or WPP)
- PPL Electric Utilities Corporation (PPL)
- PECO Energy Company (PECO)

Demand Response (DR) is a demand-side management (DSM) tool for electric utilities. It is intended to reduce the costs associated with maintaining system reliability and meeting capacity needs by reducing load during peak hours. The primary objectives of the study are as follows:

1) Estimate the DR potential in each of the seven EDC service territories.
2) Examine the costs and benefits of statewide policies to encourage the development and deployment of DR resources during Phase IV of Act 129.

1.1 PEAK LOAD CONSUMPTION

All estimates of DR potential are presented at the system-level, meaning the SWE Team adjusted them to reflect transmission and distribution system losses. This is consistent with how DR targets have been established in prior phases of Act 129. The line loss factors used to scale impacts from meter level to system level are EDC and sector-specific. These are taken from Table 1-4 of the 2021 Pennsylvania Technical Reference Manual (TRM).[1]

Modeling efforts for this study rely on PJM Interconnection's (PJM's) peak demand forecast for the first delivery year of Phase IV, as presented in the 2019 Load Forecast Report[2]. This contemporary forecast is useful for considering the relative impact of Phase IV DR on peak loads in the Commonwealth and is discussed in detail in Section 3. However, for purposes of comparing modeled Phase IV percent reductions to prior phases of Act 129 we use the original peak demand values used to establish Phase I

---

[1] *See* Volume 1 of the 2021 TRM at http://www.puc.pa.gov/pcdocs/1630967.docx.

[2] *See* https://www.pjm.com/-/media/library/reports-notices/load-forecast/2019-load-report.ashx. As discussed in Section 3, the values in the Load Forecast Report were further processed by the SWE to account for EDCs that do not serve an entire PJM zone.

targets. This legacy peak demand baseline was based on the average of the top 100 hourly loads for June 1, 2007 through September 30, 2008 and is shown in Table 1.

Table 1: Summer Peak Demand Baseline by EDC

EDC	2007-2008 Peak Demand (MW)
PECO	7,899
PPL	6,592
Duquesne Light	2,518
FE: Met-Ed	2,644
FE: Penelec	2,395
FE: Penn Power	980
FE: West Penn Power	3,496
Statewide	**26,524**

1.2 TYPE OF POTENTIAL MODELED

Energy efficiency (EE) potential modeling follows an established series of four stages: (1) technical, (2) economic, (3) achievable, and (4) program potential. There is no clear analogue for technical potential with regard to DR. Virtually all demand for electricity can be temporarily curtailed or shifted, so DR technical potential is not a meaningful output. The fundamental question for a DR potential study is how much peak demand can be reduced at a cost that is less than the supply-side alternatives to serve the load. To answer this question, we must first consider the avoided costs in place and determine what incentive levels would lead to a cost-effective program and which customers or segments are cost-effective to enroll. Incentive levels are also a primary driver of DR adoption and potential for many DR solutions, so, once incentive levels are determined, we can estimate DR potential at those incentive levels. The modeling in this report takes two perspectives with regard to this decision criterion. The details vary slightly by DR strategy, but the general definitions are as follows:

- **Realistic Achievable Potential (RAP)**: assumes that the objective of the program is to maximize net benefits (TRC benefits minus TRC costs). Incentive levels are set at a level such that benefits will be greater than costs, but still high enough to drive participation and create aggregate benefits.

- **Maximum Achievable Potential (MAP)**: assumes that the objective of the program is to maximize DR potential (MW). Incentive levels are set as high as possible while still maintaining a cost-effective program. The maximum achievable modeling perspective effectively models a "break even" program, where the TRC benefits are equal to the TRC costs. The aggregate DR potential in megawatts is larger, but the financial benefits to the Commonwealth are lower than with the realistic achievable modeling perspective.

The SWE Team believes the realistic achievable modeling perspective and results are more relevant for goal-setting and program design. The SWE encourages the Commission and readers to focus on that set of outputs. The estimates of DR potential presented in the Executive Summary (Section 1) and the values used to compare different EE/DR funding splits (in the companion Energy Efficiency Market Potential Study report) are based on realistic achievable modeling.

1.3 PROGRAM DESIGN

To evaluate DR potential for Phase IV of Act 129, the SWE Team had to make assumptions about the program design that would be implemented. Act 129 DR programs have historically operated independently of the organized electricity markets operated by the PJM Interconnection (PJM). Because Act 129 DR programs were not formally recognized by PJM in regional planning parameters, assumptions were required with respect to the impact of Act 129 programs on future reliability requirements in order to calculate TRC benefits. For this study, the SWE Team elected to model a more coordinated Act 129 DR program design that leverages the Peak Shaving Adjustment (PSA) mechanism, developed by PJM in 2019. This change provides a clear mechanism for Act 129 DR to be recognized and monetized, but drastically reduces Act 129 DR potential from the Large Commercial and Industrial (LCI) customer class because it effectively prohibits dual participation in Act 129 DR and PJM's capacity market.

Using PJM's peak shaving mechanism, the *trigger* for DR events becomes a Temperature Humidity Index (THI) threshold. Weather-based triggers like THI produce variability in the number of events called each year because some summers are hotter than others. To identify program design features that best meet objectives, the SWE investigated historic load and weather data to understand the effects of program design choices. Key program design parameters affecting DR potential include the following:

- THI threshold
- Event start hour
- Event duration
- Expected number of event hours per summer
- DR season duration
- Evaluation metric

The SWE ran hundreds of simulations that demonstrate tradeoffs in program design and the challenges of designing a single statewide program to be implemented across seven different zones with disparate weather and load conditions. Operating under the assumption that average event hours should be approximately 25 (in line with the Phase III program design which has a 24 event hour per summer limit), the design that maximizes DR performance across zones would be a three-hour event, from 3:00 pm to 6:00 pm, during the period of June through September. Table 2 shows the THI trigger modeled for each EDC.

Table 2: Temperature Humidity Index Trigger by EDC

EDC	PJM Zone	THI Threshold
PECO	PECO	82.5
PPL	PPL	81.0
Duquesne Light	DUQ	80.0
FE: Met-Ed	METED	82.0
FE: Penelec	PN	79.5
FE: Penn Power	ATSI	80.0
FE: West Penn	APS	80.0

The modeling in this report assumes that DR programs would be active in all five years of a possible Phase IV of Act 129. However, in recognition of the timing challenges associated with the summer DR season falling at the beginning of Act 129 program years, the SWE incorporated a ramping function that limits DR potential during summer 2021.

1.4 CONNECTED THERMOSTATS

The SWE Team modeled EDC load control of central air conditioning (CAC) under two types of residential connected thermostat offerings.

- **A Bring-Your-Own-Thermostat (BYOT) program**: current owners of Wi-Fi connected thermostats are offered financial incentives in exchange for allowing the EDC or its Conservation Service Provider (CSP) to modify the cooling setpoint during DR events
- **A "New Install" Connected Thermostat program**: the EDC subsidizes all or a portion of the cost of the upfront equipment and installation cost of the thermostat in exchange for the ability to control loads on event days

The eligible population for a BYOT offering is smaller because the offering is limited to households that already have a connected thermostat installed. The New Install model can be offered to any home with CAC, but the program must overcome the upfront device and installation cost. The SWE modeled both RAP and MAP for both program types, but the results shown in Table 3 and Table 4 focus on the RAP results. The present value of net benefits (PVNB) are simply the difference between present value TRC benefits and present value TRC costs.

Table 3: Statewide Connected Thermostat Potential and Budget Requirement Summary

EDC	Phase IV Potential (System Level MW)	Phase IV MWh/year Savings (Meter Level)	Budget Requirement ($1,000 Nominal)	Percent of Total EE&C Budget
PECO	43.6	7,634	$20,642	4.83%
PPL	23.6	5,902	$10,818	3.52%
Duquesne Light	0	0	$0	0%
FE: Met-Ed	13.4	3,781	$6,421	5.16%
FE: Penelec	0	0	$0	0%
FE: Penn Power	0	0	$0	0%
FE: West Penn Power	0	0	$0	0%
Statewide	**80.6**	**17,317**	**$37,881**	**3.10%**

*Statewide values in this report are summed prior to rounding. Totals may not equal the sum of all rows.

The cost-effectiveness of connected thermostat DR depends heavily on the avoided cost of transmission and distribution capacity. PECO, PPL, and Met-Ed have the highest T&D avoided costs in the state. This allows the connected thermostat offerings to pass cost-effectiveness screening. The PPL and PECO values in Table 3 and Table 4 include DR potential from both a BYOT and New Install offering. The Met-Ed potential comes exclusively from the New Install offering as the BYOT offering did not pass cost-effectiveness screening under the RAP perspective.

Table 4: Statewide Connected Thermostat Cost-Effectiveness Summary

EDC	TRC Costs (2021$)	TRC Benefits (2021$)	PVNB (2021$)	TRC Ratio
PECO	$18,036,550	$23,502,950	$5,466,400	1.30
PPL	$9,388,591	$12,409,098	$3,020,507	1.32
Duquesne Light	$0	$0	$0	N/A
FE: Met-Ed	$5,743,234	$6,573,774	$830,540	1.14
FE: Penelec	$0	$0	$0	N/A
FE: Penn Power	$0	$0	$0	N/A
FE: West Penn Power	$0	$0	$0	N/A
Statewide	**$33,168,375**	**$42,485,822**	**$9,317,447**	**1.28**

*Statewide values in this report are summed prior to rounding. Totals may not equal the sum of all rows.

1.5 BEHAVIORAL DEMAND RESPONSE

Section 6 of this report examines behavioral demand response (BDR) potential. BDR is an offering that relies on timely customer notifications to elicit reductions in demand during DR event hours without any incentives or load control equipment. Table 5 and Table 6 summarize the statewide Phase IV BDR results. BDR was a cost-effective offering for PECO, PPL, Met-Ed, and Penelec, but was not cost-effective for Duquesne Light, Penn Power, and West Penn Power. The average annual statewide DR potential for BDR is approximately 55 MW, with most of the opportunity coming from PECO and PPL service territories. Our models indicate that achieving the BDR potential would require slightly more than 1% of the statewide EE&C funding of $1.22 billion dollars for Phase IV.

Table 5: Statewide BDR Potential and Budget Requirement Summary

EDC	Phase IV BDR Potential (System Level MW)	Budget Requirement ($1,000 Nominal)	Percent of Total EE&C Budget
PECO	22.33	$4,839.4	1.13%
PPL	19.20	$4,163.3	1.35%
Duquesne Light	0.0	$0	0%
FE: Met-Ed	6.86	$1,822.1	1.47%
FE: Penelec	6.85	$1,818.9	1.58%
FE: Penn Power	0.0	$0	0%
FE: West Penn Power	0.0	$0	0%
Statewide	**55.24**	**$12,643.7**	**1.03%**

*Statewide values in this report are summed prior to rounding. Totals may not equal the sum of all rows.

Table 6 summarizes BDR cost-effectiveness. BDR shows that the highest TRC ratios are in PECO and PPL service territories, where the avoided cost of transmission and distribution capacity are highest.

Table 6: Statewide BDR Cost-Effectiveness Summary

EDC	TRC Costs (2021$)	TRC Benefits (2021$)	PVNB (2021$)	TRC Ratio
PECO	$4,407,358	$9,315,507	$4,908,149	2.11
PPL	$3,791,470	$7,534,899	$3,743,429	1.99
Duquesne Light	$0	$0	$0	N/A
FE: Met-Ed	$1,658,671	$2,073,850	$415,179	1.25
FE: Penelec	$1,655,820	$1,813,869	$158,049	1.10
FE: Penn Power	$0	$0	$0	N/A
FE: West Penn Power	$0	$0	$0	N/A
Statewide	**$11,513,319**	**$20,738,125**	**$9,224,806**	**1.80**

*Statewide values in this report are summed prior to rounding. Totals may not equal the sum of all rows.

1.6 COMMERCIAL AND INDUSTRIAL (C&I) LOAD CURTAILMENT

Table 7 and Table 8 summarize the statewide Phase IV small commercial DR results. Impacts and budget requirements are shown assuming a day-of notification program design. Impacts would be slightly larger under a day-ahead notification program design. Importantly, note that the SWE Team did not include DR potential from the LCI sector in these results because of PJM's prohibition of dual participation for PSA resources. If the Commission wishes to mimic the Phase III DR program design, relevant estimates of potential are presented in PY16 and Py17 totals rows of the "Realistic Achievable: Day Ahead" columns in Table 61 through Table 67.

Small Commercial and Industrial (SCI) DR was a cost-effective offering for all EDCs, though the potential is modest for five of the seven EDCs. The average annual statewide DR potential for SCI load curtailment is approximately 59 MW, with most of the opportunity coming from PECO and PPL service territories. This average is higher in the last two years of the phase (80 MW) than the first three (45 MW), as avoided costs are aligned with PJM's forward planning cycle (Act 129 will likely miss the opportunity for the first three years). Similar to BDR, our models indicate that achieving the SCI DR potential would require slightly more than 1% of the statewide EE&C funding of $1.22 billion dollars for Phase IV.

Table 7: Statewide SCI DR Potential and Budget Requirement Summary

EDC	Phase IV SCI DR Potential (System Level MW)	Budget Requirement ($1,000 Nominal)	Percent of Total EE&C Budget	Acquisition Cost ($/MW-year)
PECO	17.37	$4,230	0.99%	$48,705
PPL	27.58	$6,395	2.08%	$46,374
Duquesne Light	3.62	$455	0.47%	$25,138
FE: Met-Ed	4.97	$873	0.70%	$35,131
FE: Penelec	4.48	$731	0.64%	$32,634
FE: Penn Power	0.49	$19	0.06%	$7,755
FE: West Penn Power	3.56	$352	0.30%	$19,775
Statewide	**62.07**	**$13,055**	**1.07%**	**$42,065**

*Statewide values in this report are summed prior to rounding. Totals may not equal the sum of all rows.

The variance in acquisition cost between EDCs, shown in Table 7, is noteworthy. For EDCs with lower avoided costs, incentive levels must be lower for the program to be cost-effective. The low assumed incentive levels in turn lead to low estimates of DR potential because the financial offer to participants is very modest. Penn Power is the most extreme example of this issue. With an acquisition cost of less than $8/kW, there is virtually zero DR potential. If incentive levels were set higher, the program would not be cost-effective. Given that Penn Power has no connected thermostat or BDR potential, the SWE believes a practical interpretation of the results in Table 8 is that Penn Power should not have a DR program in Phase IV of Act 129.

Table 8 summarizes SCI DR cost-effectiveness. The TRC ratios are similar across EDCs because the same modeling approach (e.g., maximize net benefits) was used for all EDCs.

Table 8: Statewide SCI DR Cost-Effectiveness Summary

EDC	TRC Costs (2021$)	TRC Benefits (2021$)	PVNB (2021$)	TRC Ratio
PECO	$3,733,101	$7,480,026	$3,746,925	2.00
PPL	$5,631,836	$11,262,160	$5,630,323	2.00
Duquesne Light	$393,806	$792,657	$398,851	2.01
FE: Met-Ed	$770,924	$1,546,409	$775,484	2.01
FE: Penelec	$639,612	$1,283,677	$644,066	2.01
FE: Penn Power	$16,901	$33,589	$16,688	1.99
FE: West Penn Power	$299,976	$603,628	$303,652	2.01
Statewide	**$11,486,156**	**$23,002,145**	**$11,515,989**	**2.00**

*Statewide values in this report are summed prior to rounding. Totals may not equal the sum of all rows.

1.7 BEHIND THE METER BATTERY STORAGE

To assess the peak demand reduction potential of behind the meter battery storage, the SWE Team model incorporated TRC avoided costs, battery cost curves, and stacked value battery dispatch scenarios. The primary conclusion is that battery storage is not projected to be cost-effective during Phase IV of Act 129 using system-wide average avoided costs. Cost-effectiveness may be achieved in the presence of avoided distribution costs on the order of $300 per kW-year using projected battery costs for 2021. This magnitude of avoided cost is possible in areas where a large capital investment can be avoided or deferred through timely and dependable reductions in peak demand. Using the projected cost of battery systems for 2030 (in 2021$), the cost-effectiveness tipping point drops as low as $150 per kW-year. However, even if strategically placed battery storage applications were cost-effective from a TRC perspective, significant program support would be required for installations to make financial sense to customers who face average retail rates. Our modeling also indicates that only customers with certain load shapes would be good candidates for behind the meter battery storage.

1.8 PROGRAM POTENTIAL

Table 9 summarizes the Phase IV DR potential by EDC, along with relevant financial outputs. The estimates of DR potential are an average annual value over the five-year phase and the financials are five-year totals. If the PUC were to exclude DR performance from the first year of Phase IV, as was done for Phase III, the budget requirements and TRC costs/benefits would be reduced.

Table 9: Phase IV Demand Response Potential, by EDC

EDC	DR Potential (MW/year)	Budget Requirement ($1,000 Nominal)	Percent of EE&C Budget	TRC Costs ($1,000)	TRC Benefits ($1,000)	PVNB ($1,000)	TRC Ratio
PECO	83.3	$29,711	6.95%	$26,177	$40,298	$14,121	1.54
PPL	70.4	$21,376	6.95%	$18,812	$31,206	$12,394	1.66
Duquesne Light	3.6	$455	0.47%	$394	$793	$399	2.01
FE: Met-Ed	25.2	$9,116	7.33%	$8,173	$10,194	$2,021	1.25
FE: Penelec	11.3	$2,550	2.22%	$2,295	$3,098	$802	1.35
FE: Penn Power	0.5	$19	0.06%	$17	$34	$17	1.99
FE: West Penn	3.6	$352	0.30%	$300	$604	$304	2.01
Statewide	**197.9**	**$63,580**	**5.20%**	**$56,168**	**$86,226**	**$30,058**	**1.54**

*Statewide values in this report are summed prior to rounding. Totals may not equal the sum of all rows.

The estimates of DR potential presented in Table 9 are heavily influenced by the SWE Team's decision to model Phase IV DR as a PSA. Nomination as PSA limits potential for the following reasons:

- Dual participation as a supply resource is not allowed. Based on this limitation, the SWE Team assumed no Act 129 DR potential from the LCI sector.
- Act 129 planning timelines will not allow for PSA's to be recognized in the Base Residual Auctions (BRAs) for the five PJM delivery years corresponding to Phase IV of Act 129. This limits the avoided cost of generation capacity benefit stream.
- PSAs are expected to respond to real-time THI for dispatch. Based on this characteristic, the SWE modeled SCI load curtailment potential as a *day of* notification program instead of *day ahead* notification. This real time aspect also creates uncertainty for the residential offerings. Uncertainty translates to risk for EDCs and CSPs, which invariably drives up the cost of delivering programs.

Table 10 presents the estimates of Phase IV DR potential as a percentage of 2007-2008 peak loads.

Table 10: DR Potential Estimates as a Percent of Peak Demand Forecast

EDC	Phase IV DR Potential (System Level MW)	Percent of 2007-2008 Peak Loads
PECO	83.3	1.05%
PPL	70.4	1.07%
Duquesne Light	3.6	0.14%
FE: Met-Ed	25.2	0.95%
FE: Penelec	11.3	0.47%
FE: Penn Power	0.5	0.05%
FE: West Penn Power	3.6	0.10%
Statewide	**197.9**	**0.75%**

2 DEMAND RESPONSE PROGRAM DESIGN

DR potential is intrinsically tied to program design. In particular, the frequency and duration of DR events play an important role in customer willingness to enroll in DR and influence the expected incentive levels for participation. Although program design specifics are left up to the EDCs during their EE&C plan filings, the SWE has to make certain assumptions in order to model DR potential. The Commission also needs to clearly spell out the DR performance definition when establishing targets.

2.1 A BRIEF HISTORY OF ACT 129 DEMAND RESPONSE

DR activity in Act 129 EE&C programs has been intermittent since the legislation was enacted in 2008. The language below, from House Bill 2200[3] (Act 129 of 2008), established the initial targets for peak demand reduction.

> *By May 31, 2013, the weather-normalized demand of the retail customers of each electric distribution company shall be reduced by a minimum of 4.5% of annual system peak demand in the 100 hours of highest demand. The reduction shall be measured against the electric distribution company's peak demand for June 1, 2007, through May 31, 2008.*

Noteworthy aspects of the Phase I peak demand reduction are as follows:

- **The 4.5% peak demand reduction could be met by dispatchable DR programs or EE measures that reduce demand coincident with the system peak**. Act 129 also established a mandatory 3% reduction in energy consumption. On average, EE measures tend to produce similar percent reductions in energy consumption and peak demand. As a result, EDCs achieved approximately 54% of Phase I peak demand reduction as a byproduct of the EE measures installed to meet the 3% consumption reduction target.[4] DR programs were used to deliver the remaining peak demand reductions.

- **The measurement period for Phase I goals was summer 2012**. Because Pennsylvania is a summer-peaking system and the legislation called for reductions by May 2013, the performance period was summer 2012. Other than for testing and planning, EDCs did not operate DR programs during the first three years of Phase I.

- **The Top 100 Hours performance definition was operationally challenging**. EDCs faced significant uncertainty in predicting which hours would be part of the *Top 100*. Load reductions also had to be added back to metered loads to reconstitute system loads.[5] EDCs faced two primary risks:

---

[3] *See* http://www.puc.pa.gov/electric/pdf/Act129/HB2200-Act129_Bill.pdf.

[4] *See* the *SWE Phase I Final Report*, Table 3-25 at http://www.puc.pa.gov/pcdocs/1274547.pdf.

[5] Section 4 of the 2012 Pennsylvania Technical Reference Manual provides a detailed discussion of the demand reduction calculations under the "Top 100 hours" framework. *See* http://www.puc.pa.gov/pcdocs/1158402.docx.

- Dispatching DR programs during hours that were ultimately not part of the top 100 hours. In this scenario, the EDC incurs cost, but generates no benefits.
- Not dispatching DR programs during hours that are ultimately part of the top 100 hours. Summer 2012 started off very hot and then cooled off in early August. EDCs found themselves reserving DR resources for hot days that never arrived.

- **Cost-effectiveness was poor**. Table 11 shows the TRC costs, TRC benefits, and TRC ratios for each EDCs' Phase I DR offerings.

Table 11: Phase I Demand Response Cost-Effectiveness, by EDC

EDC	TRC Cost ($1,000)	TRC Benefits ($1,000)	TRC Ratio
PECO	$21,364	$6,197	0.29
PPL	$15,744	$5,943	0.38
Duquesne Light	$1,864	$155	0.08
FE: Met-Ed	$21,191	$4,186	0.20
FE: Penelec	$14,095	$4,104	0.29
FE: Penn Power	$2,183	$1,978	0.91
FE: West Penn	$6,426	$6,661	1.04
Statewide	**$82,867**	**$29,224**	**0.35**

Phase II of Act 129 did not include any DR targets or programs. Phase I DR program activity occurred at the end of the phase, in parallel with planning activities for Phase II of Act 129. The timing of activities did not allow for a full assessment of Phase I DR performance and cost-effectiveness in time for findings to be incorporated in Phase II goal-setting. As a result, the Commission established a relatively short Phase II (three years), with only consumption reduction targets.

To inform future DR offerings, the Commission directed the SWE to study the cost-effectiveness of the Phase I and potential future DR programs. On November 1, 2013, the SWE's Act 129 Demand Response Study was released.[6] This study included a retrospective assessment of the effectiveness of the Phase I design and compared the Phase I design with how DR is implemented and evaluated in other jurisdictions. On February 27, 2015, the SWE's Phase III Demand Response Potential Study was released.[7] The 2015 Demand Response Potential Study was prospective in nature, recommended an alternative Act 129 program design, and included estimates of DR potential and cost that formed the basis of Phase III DR targets.

Phase III of Act 129 began on June 1, 2016 and ends May 31, 2021. Key features of the Phase III DR program design and EDC targets include the following:

---

[6] *See* http://www.puc.pa.gov/pcdocs/1256728.docx. .

[7] *See* http://www.puc.pa.gov/pcdocs/1345077.docx. . The *DR Potential Study* is dated February 25, 2015 and was released February 27, 2015.

- **DR program activity for four of the five summers in Phase III**. The Commission determined that the timing of the Phase III Implementation Order and EE&C Plan filings for Phase III did not allow EDCs adequate time to ramp up DR programs for Program Year 8 (summer 2016). The Phase III performance period included the four summers associated with program years 9 through 12.

- **Demand reduction targets are for DR only**. Coincident peak (CP) demand reductions from EE measures do not count toward Phase III EDC compliance targets.

- **A narrower performance period with dispatch guidelines that limits EDC risk**. Phase III DR programs are limited to 24 hours per summer (no more than six events of duration four hours each). The Phase III performance definition that guides when EDCs call events is as follows:

    - Curtailment events shall be limited to the months of June through September and last four consecutive hours.

    - Curtailment events are triggered when PJM's day-ahead forecast for the PJM Regional Transmission Organization (RTO) is greater than 96% of the PJM RTO summer peak demand forecast for the year.

    - Once six curtailment events have been called in a program year, the peak demand reduction program shall be suspended for that program year.

    - The reductions attributable to a curtailment event are based on the average MW reduction achieved during each hour of an event.

    - Compliance is determined based on the average MW reductions achieved from events called in the four years of DR program activity.

For both Phase I and Phase III of Act 129 DR programs, EDCs were permitted to enroll participants with existing capacity commitments in PJM's emergency load response program (ELRP). In the Phase III Implementation Order, the Commission clarified that "*The EDCs, in their plans, must demonstrate that the cost to acquire MWs from customers who participate in PJM's ELRP is no more than half the cost to acquire MWs from customers in the same rate class that are not participating in PJM's ELRP.*"[8]

To date, the TRC test results of Phase III DR programs are much higher than the Phase I DR programs. Table 12 shows the TRC Costs, TRC Benefits, and TRC ratios for each EDC in PY9.

---

[8] *See* the *Phase III Final Implementation Order*, Docket No. M-2014-2424864 (entered June 19, 2015), page 44 at http://www.puc.pa.gov/pcdocs/1367313.doc.

Table 12: Program Year 9 DR Cost-Effectiveness

EDC	TRC Costs ($1,000)	TRC Benefits ($1,000)	TRC Ratio
PECO	$4,924	$13,960	2.84
PPL	$1,491	$5,656	3.79
Duquesne Light	$1,640	$5,442	3.32
FE: Met-Ed	$1,374	$3,901	2.84
FE: Penelec	$0	$0	N/A
FE: Penn Power	$821	$2,840	3.46
FE: West Penn	$1,581	$6,952	4.40
Statewide	**$11,831**	**$38,751**	**3.28**

In Program Year 4 (Phase I), the EDCs achieved 620 MW of peak demand reduction, with TRC costs of approximately $83 million. In Program Year 9 (Phase III), the EDCs achieved 497 MW of peak demand reduction, with TRC costs of approximately $12 million. The narrower definition of peak demand for Phase III, and the reduced risk regarding which hours are performance hours, are a major factor in the program acquisition costs. The treatment of participant incentives in the calculations of TRC costs also changed from Phase I to Phase III.

Per the 2016 TRC Test Order, peak demand reductions from Act 129 DR are assigned the full avoided cost of capacity. This assumption was flagged for further investigation in the SWE Program Year 9 Annual Report[9] and addressed in the 2021 TRC Test Order[10], which put forth a more conservative methodology for calculating TRC benefits from DR. While Act 129 DR programs have evolved considerably since Phase I of Act 129, there have also been significant developments at PJM in the way DR is recognized in wholesale market operations. Section 2.2 discusses development at PJM and implications for DR programs in Phase IV of Act 129.

2.2 DEMAND RESPONSE IN PJM

Act 129 Phase IV DR Potential will be influenced by, and will interact with, PJM's treatment of DR resources. PJM's current capacity performance rules require resources participating in the capacity supply market to be capable of reductions year-round, on consecutive days, and for 16 hours per day. This definition excluded many existing DR programs, such as utility direct load control of central air conditioners, which were operating in the PJM territory.

In response, PJM convened a Summer Only Demand Response Senior Task Force (SODRSTF) to explore means of valuing resources that may not have been able to clear in the capacity supply market. Over the course of nine months, SODRSTF members brought forth various proposal packages with different design components. Through a collaborative process, PJM adjusted its proposal to settle on a

---

[9] *See* the *SWE Annual Report Act 129 Program Year 9*, pgs. 13-14, at http://www.puc.pa.gov/Electric/pdf/Act129/Act129-SWE_AR_Y9_022819.pdf.

[10] *See* the *2021 TRC Test Final Order*, Docket No. M-2019-3006868 (entered December 19, 2019), pgs. 86-97, at http://www.puc.pa.gov/pcdocs/1648126.docx.

PSA mechanism, which received 65% support from the task force. In October 2018, the Markets and Reliability Committee of PJM voted in favor of a motion to adopt the proposal for creation of a PSA mechanism. In May 2018, FERC approved revisions proposed by PJM to reflect load reductions from DR resources in the forecasts for the PJM capacity market.

2.2.1 PEAK SHAVING ADJUSTMENT

The new PSA will treat summer-only DR resources in a fundamentally different way. Rather than being counted as supply capable of meeting resource requirements, summer only DR will now be included on the demand side of the market by reducing the peak load forecast for a participant's zone. The valuation of a PSA will be dependent on the magnitude, frequency, and duration of peak shaving. PJM will apply submitted program parameters to historical forecasts and examine the hypothetical effectiveness in reducing peak demand. The PSA represents value in terms of avoided capacity purchases and any associated price suppression effects.[11]

At the conclusion of each summer, PJM will compare the programs' actual curtailment for each event to the committed values. PJM will use the average performance factor of the previous three years as assumed performance in future forecasts. Thus, there is no direct cost penalty for non-performance, but underperforming will reduce peak shaving magnitudes in future program years.

DR events for PSA resources will not be dispatched by PJM, but rather triggered based on THI, which PJM uses in its load forecasting models. Program administrators must select a THI threshold for their Peak Shaving program and must dispatch the program whenever that THI threshold is met. The weather-based trigger introduces uncertainty into the program in both determining whether to call events and the year-to-year fluctuations that may result in more or fewer event calls.

More information concerning the PSA mechanism can be found in PJM Manual 19.

2.3 IMPLICATIONS FOR PENNSYLVANIA

The PSA mechanism at PJM is, in some respects, well-suited for Act 129 DR programs. It provides an explicit mechanism through which summer DR programs can be recognized in the market. However, there are a series of administrative challenges related to participation and the timing of key activities that will need to be addressed by the Commission in order to remove the barriers to Phase IV DR.

First, resources participating as PSA are not eligible to participate on the supply side of PJM's capacity market. This will have significant impacts on Pennsylvania DR potential as many of the LCI participants in Act 129 Phase III DR programs also have capacity commitments at PJM. The SWE believes that many of the LCI participants in Act 129 Phase III DR programs would opt to continue participating through their capacity commitments at PJM, thus making them ineligible for Act 129 Phase IV DR.

Second, the timeline associated with PJM's PSA does not align well with Pennsylvania program cycles. By necessity, the commitment cycle for PSAs will precede the BRA for generation capacity. The BRA for

---

[11] For further information on price suppression effects, *see* https://www.demandsideanalytics.com/wp-content/uploads/2019/03/Summer-Peak-Shaving-Adjustment-Programs-at-PJM.pdf.

a delivery year is held in the spring, three years prior to the delivery year. For example, the BRA for the 2024/2025 delivery year (June 1, 2024 to May 31, 2025) is expected to be held in May 2021. Key dates for the 2024/2025 delivery year are as follows:

- **November 2020** – EDC Phase IV EE&C Plans due to the Commission.
- **December 2020** – PJM releases it's 2021 Peak Load Forecast. This forecast will not reflect any adjustments for Peak Shaving.
- **February 1, 2021** – PSA program parameters must be submitted to PJM.
- **March 15, 2021** – PJM publishes a new Peak Load Forecast inclusive of PSAs.
- **May 2021** – BRA for 2024/2025 delivery year.
- **June 1, 2024** – Beginning of the 2024/2025 delivery year. PSAs nominated in February 2021 are expected to perform when the THI trigger is met.

This advanced schedule presents a number of challenges for Act 129 Phase IV DR. PJM requires details on PSAs prior to the BRA, which occurs three-year prior to the beginning of the delivery year. This means that, by the time EDCs have a Phase IV DR target and EE&C plan, all but two BRAs for Phase IV program years will have passed[12]. PJM will also allow peak shaving nominations in incremental auctions, which helps mitigate the timing issue, but it is unclear how the clearing prices in incremental auctions will compare to the BRA. The Commission must also decide whether it will direct EDCs to nominate peak shaving resources beyond the end of Phase IV when no Act 129 EE&C program currently exists. The peak shaving mechanism does not have financial penalties for non-performance, which helps reduce the EDC risk profile, but it is unclear if Act 129 would accommodate nomination of peak shaving resources beyond the phase terms.

In either regard, there is another complication associated with the timeline: the PSAs commit in advance of the auction, which sets the resource clearing price (RCP). This means a PSA must commit to peak shaving activity without knowing what the value of that shaving will be. Program administrators can look at historic clearing prices and base decisions to commit on estimated values, but uncertainty will remain. Further, there is no mechanism to withdraw a commitment based on price, other than non-performance.

2.4 RECOMMENDED DESIGN

While there are clearly administrative challenges aligning Act 129 EE&C plan cycles with PJM's forward planning timeline, the SWE Team believes the PSA mechanism creates the clearest path for valuing Act 129 DR. Leveraging the newly created PSA mechanism means the trigger for DR events will need to be based on a zonal THI threshold rather than the day-ahead load forecast. This creates uncertainty in the number of events called across zones and from year to year based on weather variation. To identify program design features that best meet objectives, the SWE investigated historic load and weather

---

[12] The BRA calendar at PJM is currently behind its traditional schedule because of the delays waiting for FERC ruling on state-subsidized generation. Depending on the extent of the delay, it may be possible for Act 129 DR to be reflected in the 2023/2024 BRA as PSA.

data to understand the effects of program design choices. The peak shaving parameters that must be provided to PJM include the following:

- THI threshold
- MW commitment
- Event start hour
- Event duration
- DR season duration (May to September, June to August, etc.)

The SWE ran hundreds of simulations for all seven Pennsylvania EDCs, varying each of the program design parameters and evaluating the performance across metrics under different event hour caps. The results illustrate the tradeoffs inherent in program design when trying to maximize DR performance with a limited number of event hours. The fundamental challenge is designing a single statewide program to be implemented across seven different zones with disparate weather and load characteristics.

The results suggest two main conclusions:

1) There is not a single program design that maximizes program metrics for each of the seven zones. Because the load profiles and weather conditions vary across zones, the optimal program design to capture the largest percentage of target load and highest number of coincident peak hours are different for each zone. To select a single program design, it is necessary to consider how to evaluate results across zones and decide which metrics are most important.
2) A single THI threshold used across zones will result in drastically different numbers of anticipated event hours. As such, to achieve a program design in which DR event hours are relatively consistent from EDC to EDC, different THI thresholds will need to be used for each zone regardless of the choice of other design parameters.

The effectiveness of DR programs in reducing peak load are constrained by practical considerations, which limit the total number of event hours. Program budgets would be exhausted by a large number of DR events and potential participants may suffer event fatigue if called repeatedly or for long durations. Furthermore, the timing of the system peaks and number of days exceeding THI thresholds cannot be predicted with perfect accuracy. These limitations challenge the ability to quantitatively estimate DR program impacts.

However, by considering how various program design options change outputs using historical load and weather conditions, we can begin to understand the tradeoffs between event criteria. For each zone the SWE Team ran over 1,750 simulations; each scenario had a different combination of event parameters. Table 13 defines each input parameter and presents the range of values explored in the simulations.

Table 13: DR Program Parameters

Parameter Name	Description	Value Range		
		Minimum	Interval	Maximum
THI Threshold	Value of the THI at which a DR event will be triggered.	75	0.5	85
Event Start Time	What time will the event start?	12:00 pm	1	5:00 pm
Event Duration	How long does each event last (in hours)?	2	1	8
End Month*	In which month are the last DR events called?	8	1	9
*All scenarios begin the DR season in June. Including the month of May did not significantly change results.				

The SWE Team also experimented with how to assess the effectiveness of different designs. The ultimate effectiveness metric will be determined by how much PJM lowers the load forecast for the zone. This *credit* is determined via parallel runs of the PJM peak load forecast. First, PJM runs the peak load forecast normally. Then they edit the 20-years of historic load data to subtract the nominated shaving behavior and rerun the forecast. The credit is the difference between those two forecasts. However, the SWE Team cannot ask PJM to consider thousands of possible designs, so proxy metrics are needed. For each scenario, the SWE Team defined the performance based on two criteria:

1) **Effective Load Carrying Capacity (ELCC)** – A measure of the relative importance of hours of availability for DR dispatch. The SWE Team calculated ELCC as the percentage of target load that is captured by a simulated DR event. The target load is all demand above 90% of the forecasted system peak for the year. Thus, if the forecast system peak for a zone in 2019 was 10,000 MW, any hour with more than 9,000 MW of demand would contribute to the target load. Hours with higher demand contribute more to the total target load and thus weigh more heavily in the calculation of ELCC. The embedded assumption is that these hours/loads are driving the peak load forecast for the zone.

2) **Five Coincident Peak (5CP)** – The five days and hours of highest peak load. Performance is expressed as the percentage of the five system peak hours that are hit by DR events. The system peak hours are defined RTO wide and represent the five hours of highest system demand for a given delivery year, which occur on five different days.

The SWE Team believes that these metrics adequately capture DR's ability to reduce PJM peak load forecasts and directly compare across all scenarios. The 5CP metric places more emphasis on correctly hitting the single hours of highest load, whereas ELCC is based on total target load covered. The 5CP metric also likely translates well to the participant's perceived value because their consumption during the 5CP hours is often used to calculate their Peak Load Contribution (PLC) and allocation of capacity costs.

2.5 DATA AND METHODOLOGY

The simulations used weather data from 1998 to 2018, with station weights derived from PJM Manual 19.[13] The SWE Team calculated the THI for each hour of every year, and retrieved load data for each zone from PJM Data Miner 2,[14] which spans from 2006 to 2018.[15] In addition, the SWE obtained the forecasted system peak load for each zone and the 5CP days and hours from PJM. PJM zones and Pennsylvania EDC service territories are highly related, but not interchangeable. Table 14 maps the seven Pennsylvania EDCs subject to Act 129 to the relevant PJM zones.

Table 14: Mapping Table of EDC Territory to PJM Zone Mapping

EDC	PJM Zone	Notes
PECO	PECO	
PPL	PPL	
Duquesne Light	DUQ	
FE: Met-Ed	METED	PJM zones also includes some small co-op and municipal utility load
FE: Penelec	PN	
FE: Penn Power	ATSI	Most ATSI load is in Ohio. Penn Power is a small subset of ATSI load
FE: West Penn	APS	APS zone also includes areas of Maryland and West Virginia served by FirstEnergy

Using the historical PJM load forecasts, the target load for each zone-year were set at 90% of the forecasted summer peak for that zone. Each hour in which demand exceeds 90% of the peak has a target load value:

$$Zonal\ Target\ Load = Zonal\ Hourly\ Demand - 0.90 * Summer\ Zonal\ Peak\ Load$$

Target load represents load available for DR, not necessarily the peak shaving that would be achieved. The SWE Team then ran the simulations through a series of loops in which the program design parameters are systematically changed so that every possible combination of event parameters is studied.

Within each scenario definition, the SWE flagged any day with a THI value above the threshold for that scenario as an event day. For each event day, the event start hour and event duration parameters dictate the event hours. The *captured load* is the sum of target load during all event hours for that scenario. The ELCC is then the ratio of captured load to total target load for each zone-year. The 5CP value represents the share of the five peak hours that were hit by a DR event. The final step was to average across years in the sample to produce a mean number of event hours, ELCC, and 5CP for each zone. The SWE Team stored this value and ran the next scenario.

---

[13] *See* https://www.pjm.com/directory/manuals/m19/index.html#about.html.

[14] *See* https://dataminer2.pjm.com/feed/hrl_load_metered.

[15] The ATSI zone was not a part of PJM in 2006 and does not have load data until 2012.

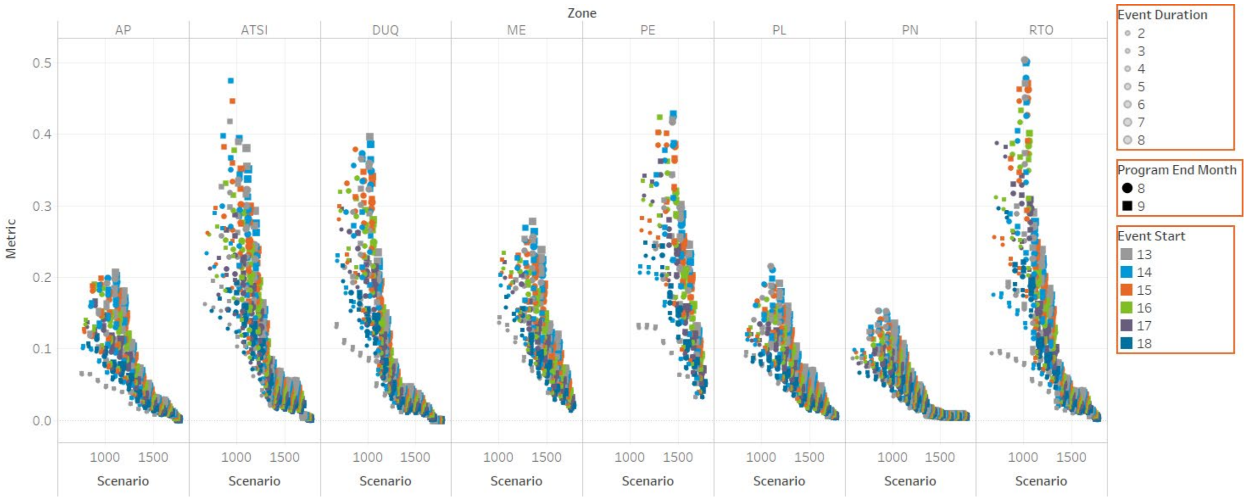
The results for all of the simulation scenarios have been visualized in Tableau. Accompanying this report is an online dashboard that allows the user to explore sets of scenarios and the impacts of changing parameters on their own. In the dashboard, and the figures included in this report, hour values are presented in hour ending format. This means hour 1 represents the period from 12:00 am to 1:00 am. Table 15 provides a legend to facilitate interpretation.

Table 15: Time Convention

Hour	Definition	Hour	Definition
1	Midnight to 1:00 am	**13**	Noon to 1:00 pm
2	1:00 am to 2:00 am	**14**	1:00 pm to 2:00 pm
3	2:00 am to 3:00 am	**15**	2:00 pm to 3:00 pm
4	3:00 am to 4:00 am	**16**	3:00 pm to 4:00 pm
5	4:00 am to 5:00 am	**17**	4:00 pm to 5:00 pm
6	5:00 am to 6:00 am	**18**	5:00 pm to 6:00 pm
7	6:00 am to 7:00 am	**19**	6:00 pm to 7:00 pm
8	7:00 am to 8:00 am	**20**	7:00 pm to 8:00 pm
9	8:00 am to 9:00 am	**21**	8:00 pm to 9:00 pm
10	9:00 am to 10:00 am	**22**	9:00 pm to 10:00 pm
11	10:00 am to 11:00 am	**23**	10:00 pm to 11:00 pm
12	11:00 am to Noon	**24**	11:00 pm to Midnight

The ELCC values for all scenarios with an average of less than 25 event hours per year are shown for all zones in Figure 1. This image demonstrates the variation in DR program performance across zones but is not particularly informative as it includes hundreds of scenarios with a wide range of event parameters and all zones on a single image. To illustrate the effect of design criteria, the SWE presents figures that show results from varying one parameter at a time for the RTO region. Then the SWE Team returned to an examination of results across zones with a narrower set of scenarios to determine an optimal program design.

Figure 1: Mean ELCC all scenarios (< 25 event hours)

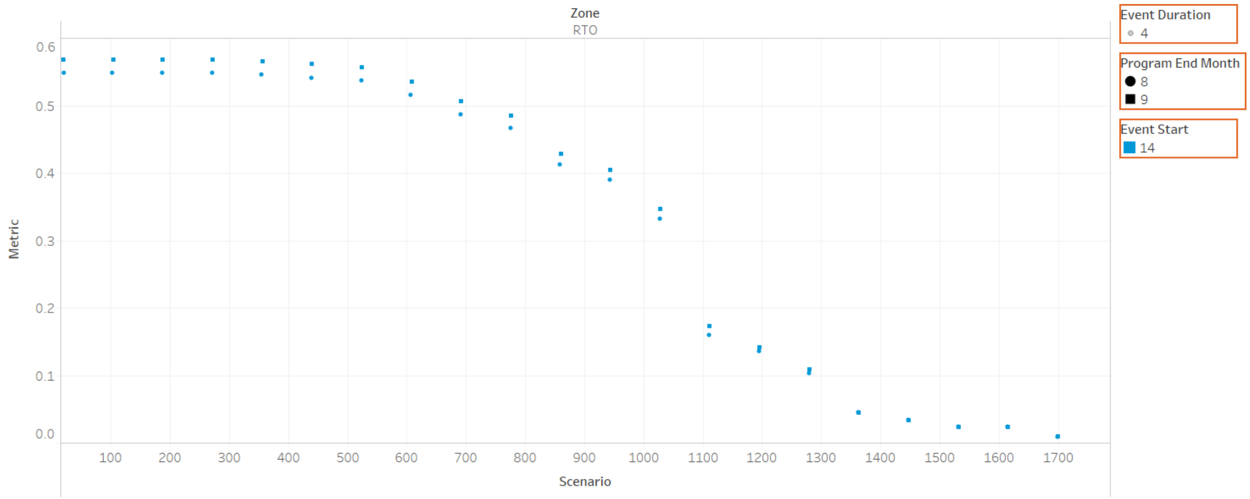


Across all visuals, the coding of points is systematic. Each event start hour is represented with a different color. The size of the point gets larger as the event duration increases. Square dots represent scenarios that include September in the DR season, while circles represent scenarios in which DR events stop being called in August.

2.5.1 THI THRESHOLD

The first program parameter is the THI value at which a DR event is triggered. Lower scenario numbers are associated with lower THI values and higher scenario numbers indicate higher THI values. At each THI value, there are 84 scenarios reflecting all possible combinations of the other parameters. Figure 2 illustrates the results for RTO wide ELCC when the event duration and event start are held constant.

Figure 2: Mean ELCC for RTO, by THI Threshold



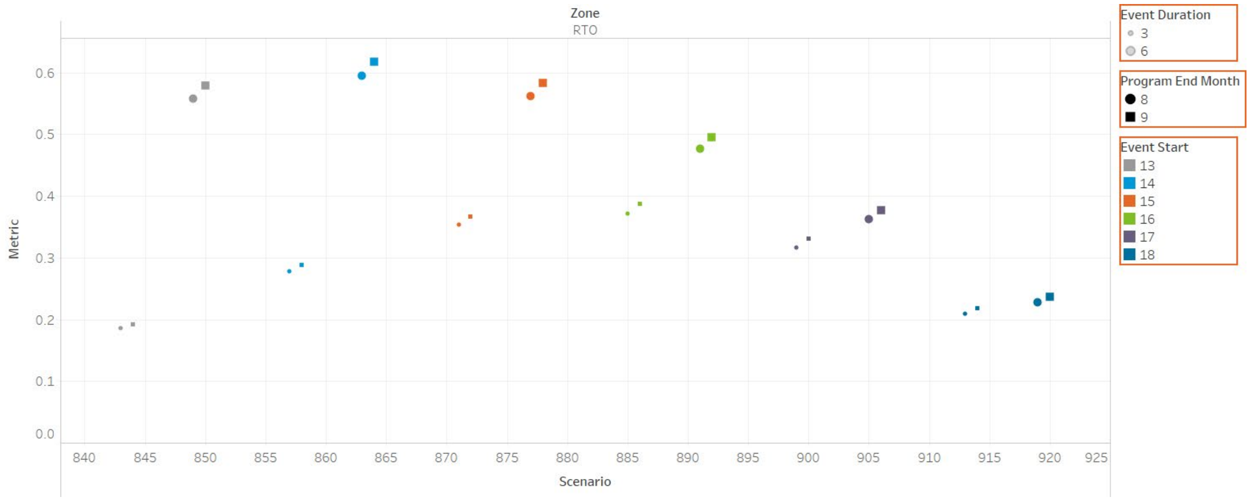
As can be seen in the figure, lower THI thresholds result in a greater percentage of captured target load. This is entirely driven by the fact that lower THI thresholds result in a higher number of event days. For the RTO zone, a THI threshold of 78 (scenario 524) results in an average of 80 event hours per year. Lowering the THI threshold further generates additional event hours but does not improve the ELCC metric. At the other extreme, THI thresholds beyond 83.5 (scenario 1447) result in an average of less than one event hour per year.

Another interesting result that can be examined in Figure 2 is the interaction of the THI threshold and the program end-month. There is a significant performance increase (although more event hours) when including September in the DR season if the THI is relatively low. At higher thresholds, the difference disappears as September fails to produce any triggering THI values.

2.5.2 EVENT START HOUR

The event *start hour* dictates at what point on event days participants are instructed to begin load reduction. As expected, the optimal start hour depends on the event duration. For longer events, the performance is better when events start earlier as this captures more of the peak. Shorter events need to start later in the day in order to maximize the target-load captured. For example, in Figure 3, which shows RTO scenarios at an 80 THI threshold, an event duration of three hours should begin at hour 16 (3:00 pm), whereas a six-hour event should begin at hour 14 (1:00 pm) to maximize performance. It is worth noting that while the longer event durations result in better ELCCs, it comes at the cost of more event hours. A program design with six-hour events at the same THI threshold yields twice as many average event hours as a design with three-hour events.

Figure 3: Mean ELCC for RTO, by Start Hour



The optimal event start time differs by zone (even for a program with the same event duration), which complicates matters. For example, while a three-hour event performs best starting at hour 16 (3:00 pm) for the RTO, for the ATSI zone (Penn Power), the preferred start is hour 14 (1:00 pm). These discrepancies are based on different peak hours and the kurtosis of the load curve. In Table 16, the SWE presents the optimal start hour by event duration for each zone under the constraint that average event hours are capped at 25.

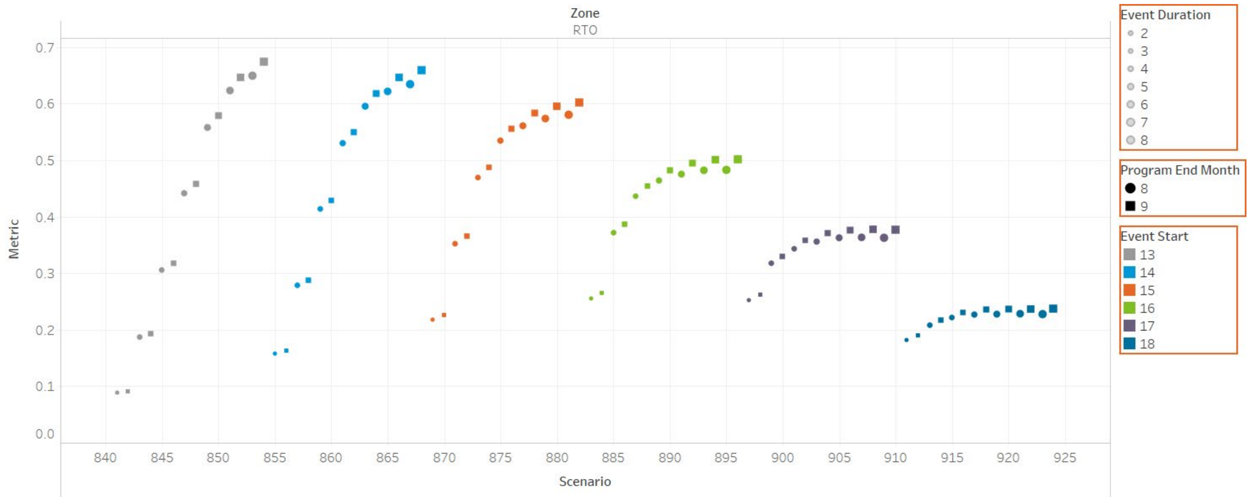
Table 16: Start Time with Highest ELCC, by Zone

Event Duration (Hours)	Optimal Event Start Time (All Times PM – Eastern Daylight)							
	APS	ATSI	DUQ	METED	PECO	PPL	PN	RTO
Two hour	3:00	2:00	3:00	3:00	4:00	3:00	1:00	4:00
Three hour	3:00	1:00	2:00	2:00	3:00	2:00	1:00	3:00
Four hour	2:00	1:00	2:00	1:00	2:00	1:00	1:00	2:00
Five hour	1:00	1:00	1:00	1:00	1:00	11:00	12:00	2:00
Six hour	1:00	1:00	1:00	12:00	1:00	12:00	12:00	1:00
Seven hour	12:00	12:00	12:00	12:00	12:00	12:00	12:00	12:00

2.5.3 EVENT DURATION

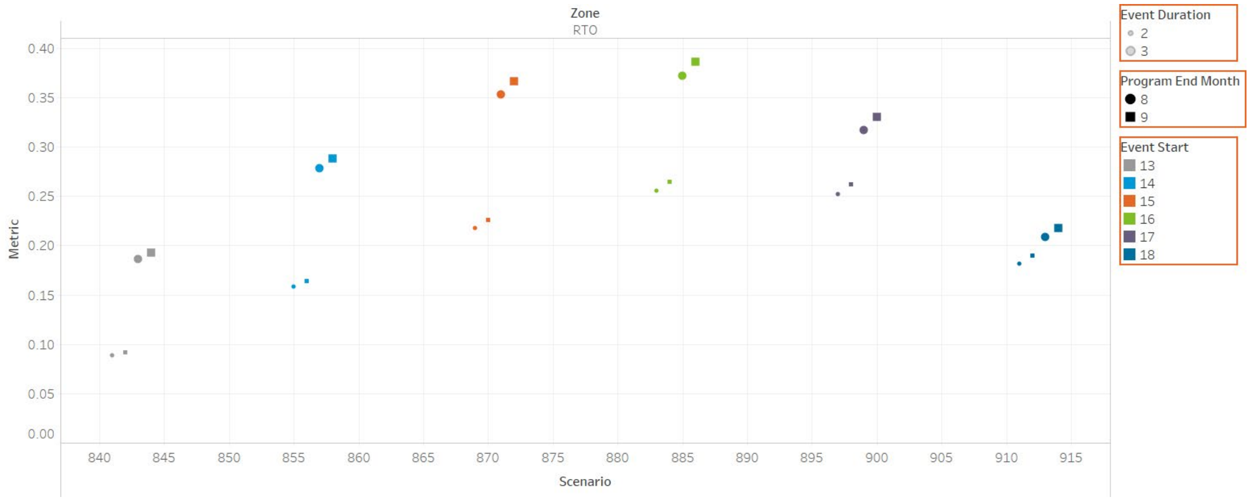
The event start hour and event duration are unquestionably linked. As can be seen in Figure 4, regardless of the start hour, a longer event results in a higher ELCC. Without considering the number of event hours, a program that begins in hour 13 (12:00 pm start time) and lasts eight hours will perform best at any given THI threshold. However, as the event start hour moves later in the day, the marginal benefits of adding an hour to the event duration decrease.

Figure 4: Mean ELCC for RTO, by Event Duration



This becomes relevant when taking the average number of event hours in the program design into account. Figure 5 shows the same program design criteria as Figure 4, but with all the scenarios that result in more than 25 event hours on average removed. Only two-hour and three-hour events are left, and the optimal start is hour 16 (3:00 pm to 4:00 pm).

Figure 5: Mean ELCC for RTO, by Event Duration (Event Hours < 25)

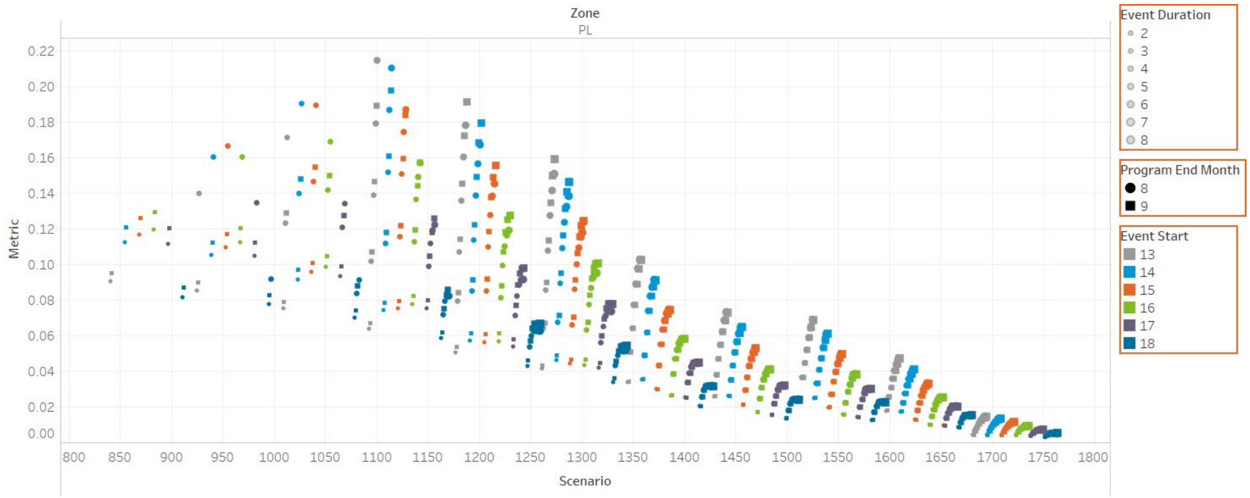


This tradeoff between performance, average number of event hours, and event duration also impacts the metric decision. To this point, all of the images have displayed ELCC. However, when evaluating scenarios based on 5CP metrics, the performance of shorter events is typically better as the same number of event hours yields more event days and a higher likelihood of capturing the five peak hours.

2.5.4 PROGRAM END MONTH

Generally, including September in the DR program season improves performance. The differences are more significant for the ELCC metric than the 5CP metric because, historically, relatively few 5CP hours have occurred in September. That said, including September does yield an increase in the average number of event hours. If the program design seeks to limit total event hours, then a design that excludes September may be preferred. The marginal benefits of including September also vary from zone to zone. When examining all the scenarios that result in less than 25 event hours on average for the PL zone, the winning designs exclude September, as shown in Figure 6.

Figure 6: Mean ELCC for PL (Event Hours < 25)



2.6 OPTIMAL PROGRAM DESIGN

As demonstrated above, changing more than one program design variable at a time can have interactive effects. This makes it difficult to compare programs with different combinations of parameters, particularly when the effects of changes may differ across zones. Figure 1 displayed all the scenarios with less than 25 event hours on average. Ideally, we could simply select the scenario that performs best in each zone. However, if the program needs to be consistent across the state, the same program design does not win in every zone. This is further demonstrated in Table 17, which shows the program design with the highest ELCC for each zone.

Table 17: Highest ELCC, by Zone (< 25 Event Hours)

Zone	THI Threshold	Event Start	Event Duration	End Month	ELCC	Average Event Hours
APS	81.5	12:00 pm	7	9	20.63%	23.86
ATSI	80.5	1:00 pm	4	9	47.52%	23.82
DUQ	81.0	12:00 pm	7	9	39.61%	24.50
METED	83.0	12:00 pm	7	9	27.78%	24.82
PECO	83.5	1:00 pm	6	9	42.80%	22.91
PPL	81.5	12:00 pm	6	8	21.44%	24.82
PN	80.0	12:00 pm	5	8	15.25%	24.77
RTO	81.0	1:00 pm	6	9	50.00%	23.45

Not only are the ELCC results different across zones, but the optimal program design is different in the same zone when looking at the 5CP performance metric. Table 18 shows the top program design using the 5CP performance metric in each zone. As expected, 5CP has lower THI thresholds with shorter events.

Table 18: Highest 5CP, by Zone (< 25 Event Hours)

Zone	THI Threshold	Event Start	Event Duration	End Month	5CP	Average Event Hours
APS	80.0	3:00 pm	3	9	67.69%	24.95
ATSI	79.5	4:00 pm	2	9	67.50%	20.73
DUQ	79.0	3:00 pm	2	9	66.15%	24.00
METED	81.0	3:00 pm	2	9	64.62%	24.36
PECO	81.5	3:00 pm	2	9	60.00%	24.64
PPL	80.0	3:00 pm	2	9	66.15%	22.27
PN	79.5	3:00 pm	3	9	64.62%	23.73
RTO	79.5	3:00 pm	2	9	69.23%	20.09

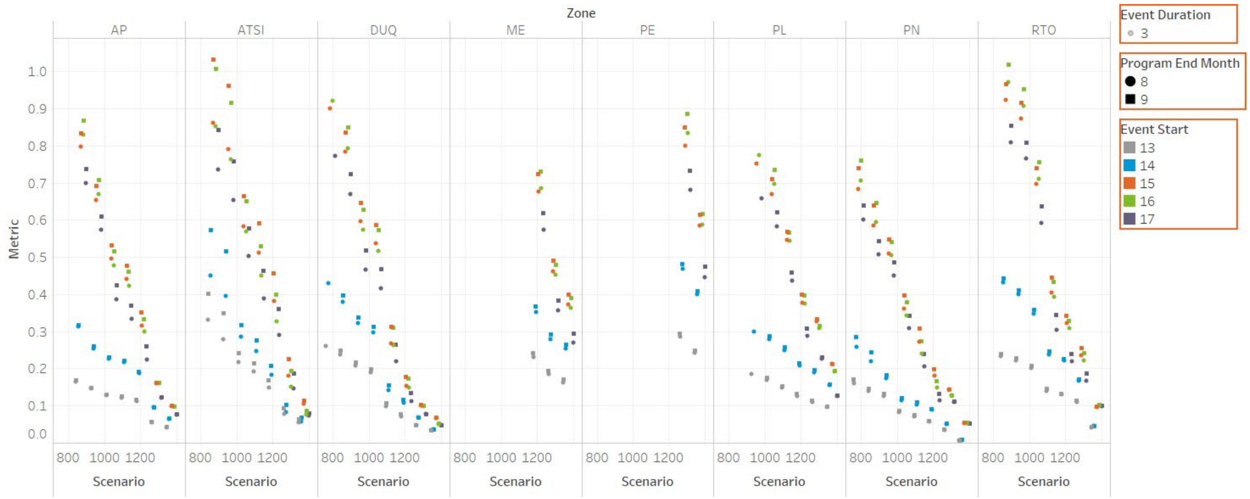
Despite the obvious discrepancies, there are some similarities that can inform an overall selection. First, all the top designs cover 3:00 pm to 5:00 pm, so regardless of the zone or metric, these hours will need to be captured by the DR program design. Second, the THI threshold can be restricted to between 79 and 83.5 since no winning designs come from outside that range.

To capture both the ELCC and the 5CP metrics in a single view, the SWE took advantage of the fact that both metrics are percentage based. By evaluating a new metric (the sum of those two numbers)[16] the SWE captured both impacts. The results indicate that all winning program designs are either two, three, or four event hours. A three-hour event is both the median and the mode across zones, so the SWE Team examined the results for three-hour events across all zones. Figure 7 shows that for every zone except ATSI, the optimal three-hour event with less than 25 event hours begins in hour 16 (3:00 pm). Further, with the exception of Duquesne and PPL, the performance is better when including the month of September.

---

[16] If one metric is deemed more important than another, a weighted sum could be used.

Figure 7: Sum of ELCC and 5CP for Three-hour Events, by Zone



These results indicate that, when considering the performance across all zones and blending the desire to achieve both high ELCC and 5CP metrics, the optimal DR program design across zones is for events to be called from 3:00 to 6:00 pm in June through September. If zones share these program design parameters, they will have different THI triggers by necessity.[17] Table 19 shows the optimal THI trigger for the recommended program design.

Table 19: Optimal THI for Recommended DR Program Design, by Zone

EDC	PJM Zone	THI Threshold
PECO	PECO	82.5
PPL	PPL	81.0
Duquesne Light	DUQ	80.0
FE: Met-Ed	METED	82.0
FE: Penelec	PN	79.5
FE: Penn Power	ATSI	80.0
FE: West Penn	APS	80.0

2.7 UNCERTAINTY AND RISK

While searching for a program design that produced the best results across zones, the SWE imposed a cap of 25 hours on the average number of event hours that the program would be likely to generate in a given year. However, there are a number of sources of uncertainty that introduce risk into the program. An *average* of less than 25 event hours means that EDCs will likely call more than 25 event hours' worth of events in some years and much less in other years. In Table 20, the SWE Team presents additional

---

[17] This could result in EDCs calling DR events on different days, but it is intended to prevent some zones from calling far more events than other zones.

metrics (median, min, max, standard deviation) to help illustrate the wide range of event calls that are possible under a THI based trigger.

Table 20: Variation in Hypothetical Event Calls, by Zone (1998-2018)

Zone	THI Threshold	Average Events	Median Events	Minimum Events	Maximum Events	Standard Deviation
APS	80.0	8.00	7	2	15	4.32
ATSI	80.0	8.31	7	3	21	5.41
DUQ	80.0	7.77	9	2	13	4.07
METED	82.0	7.23	6	2	14	4.23
PECO	82.5	7.38	6	2	17	4.05
PPL	81.0	7.31	7	1	17	4.25
PN	79.5	7.69	7	1	14	4.01
RTO	80.0	7.54	8	1	16	4.61

Based on weather data from the past 20 years, a single THI trigger could result in a range of more than 50 event hours from year to year. Given the target of around 25 event hours per year, this is a wide range. Furthermore, there is inherent risk in using past weather values to predict future event triggers as historic weather may not be indicative of future weather. Weather variability concerns are compounded by only having two eligible DR summers during Phase IV because there are fewer years for weather patterns to even out.

Another source of risk is in forecasting day-to-day weather and determining if an event should be called. The PJM peak shaving design relies on real time THI, so EDCs would lose the certainty they have had in Phase III, where they received over 24-hours' notice of an upcoming event. With a THI trigger PJM doesn't dispatch, and the EDC or its CSP must watch the weather and perform. Based on weather forecasts, EDCs would know when an event was *likely*, and the uncertainty would be reduced as the potential event draws closer. However, weather is inherently unpredictable, which introduces risk that is not present in Phase III. Risk is invariably priced in the market so this program design consideration has implications for the economics of Phase IV DR.

The further out an EDC tries to anticipate the THI trigger, the greater the possibility an event is called when one is not warranted, or an event is missed when it should have been called. For example, if a thunderstorm passes through, the forecasted THI values may not materialize. If an EDC tries to wait until the THI threshold is reached, they would have very limited notification time. While this would not be a problem for residential direct load control or smart thermostat DR, it creates a barrier for behavioral programs and C&I. Looking at historical data, on days where the THI threshold is reached, it typically occurs before 4:00 pm, but there are instances where the THI trigger is only reached after the hypothetical event start. So while EDCs will typically know an event has been triggered in advance of the event start, the advance notice is variable. EDCs and their CSPs would not be able to provide the same level of advance notice and certainty they have become accustomed to in Phase III, which may reduce DR potential.

2.8 CONCLUSIONS

Any DR program design criteria will impose limits on the amount of DR potential in Phase IV. The limits are a derivative of program budgets, which make it necessary to limit the number of potential DR event hours. For this scenario exploration, the SWE assumed that the average number of event hours in a DR season should not exceed 25 as this is in line with Phase III event hour caps. In these simulations, the SWE attempted to quantitatively explore the relative effectiveness of DR under a variety of potential program designs.

While the effects of changing a single program parameter are relatively straightforward, there are interactions between parameters when operating with a limit on event hours. Further, the performance of each scenario varies across zones and depends on the evaluation metric being used. Based on our investigation, the SWE Team chose to model a program design consisting of three-hour events starting at 3:00 pm and being called June through September.

Potential Phase IV participants are also likely to hold preferences about the design of the program, which may not align with each other or the ultimate decision of the Commission. This could affect participation. Thus, the simulations provide an estimate of the natural limits, but are not intended to illustrate how participants would react to a given program design. Finally, the SWE Team wants to be clear that these simulations represent estimates based on historical data and may not be indicative of future performance. Displaying values averaged over 20+ years of data can mask significant variation likely to occur from year to year. The uncertainty associated with weather introduces risk and will have an associated cost for implementation.

2.9 RESULTS OF PJM SIMULATIONS

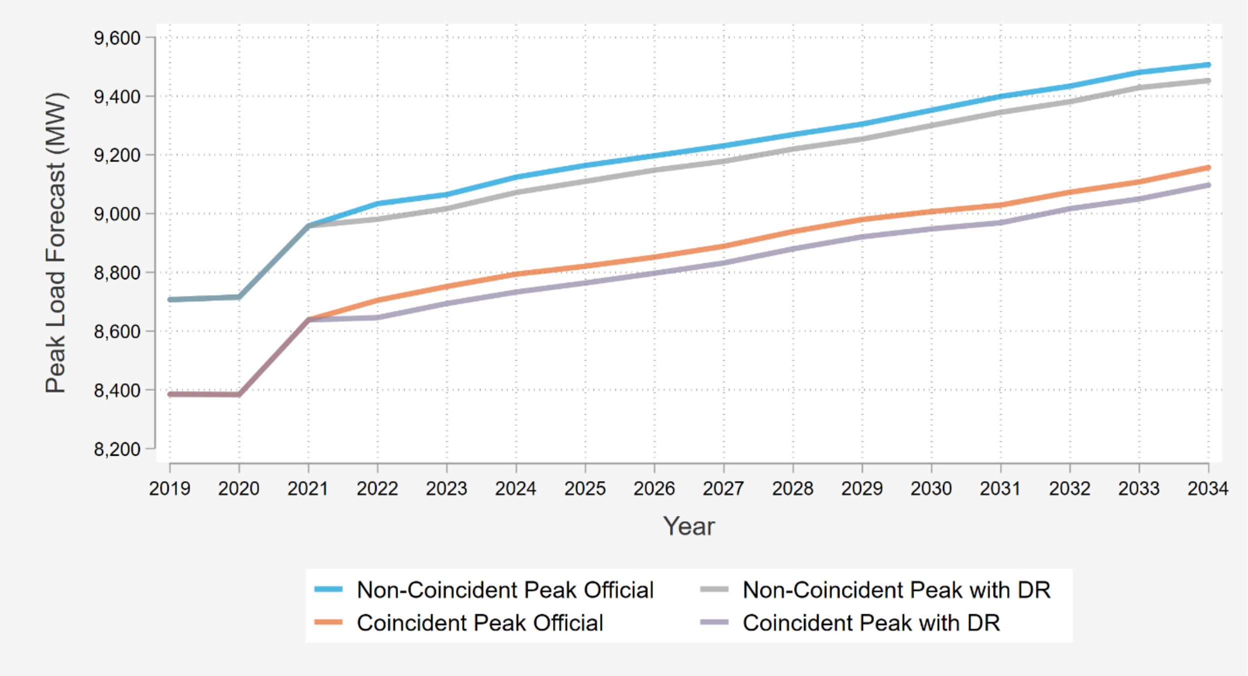
Based on the simulation results and recommended program design in the previous sections, the SWE Team reached out to PJM’s Load Forecasting group to model the impact of a hypothetical set of Act 129 peak shaving programs on zonal peak load forecasts. The SWE Team assumes the hypothetical program design to be active non-holiday weekdays, June through September, with hours ending 16, 17, and 18 (3:00 pm to 6:00 pm). Table 21 shows the assumed THI trigger and the magnitude of peak shaving, which were set to generally match Phase III DR targets for each EDC.

Table 21: DR Program Characteristics for PJM Sensitivity Analysis

Zone	EDC	MW	THI Trigger
APS	West Penn Power	75	80
ATSI	Penn Power	15	80
DUQ	Duquesne Light	50	80
METED	Met-Ed	50	82
PECO	PECO	150	82.5
PPL	PPL	100	81
PN	Penelec	50	79.5

Figure 8 illustrates the output of PJM's simulation using APS zone (West Penn Power) as an example. For each zone, four forecasts were provided. One set of forecasts (blue and grey lines) is the CP – or APS zone's contribution to the PJM system peak as a whole. The other set (orange and purple lines) are the non-coincident peak (NCP) forecast for APS zone at any time, without regard for the balance of the PJM system. The *official* forecasts are the same as the official 2019 Load Forecast Report,[18] discussed in Section 3 of this report. The other two forecasts reflect the load forecast assuming the peak shaving programs in Table 21. Beginning in 2022, the two forecasts diverge as the peak shaving programs lower the forecasted peak demand for APS zone.

Figure 8: PJM Simulation Outputs – APS Zone



---

[18] *See* https://www.pjm.com/-/media/library/reports-notices/load-forecast/2019-load-report.ashx.

The key question for valuation of DR and calculations of DR cost-effectiveness is how much the 75 MW of peak shaving in APS lowered the CP demand forecast. In Figure 8, this corresponds to the average difference between the orange and purple lines. In APS, the average difference in the two CP forecasts 2022-2034 is 58.3 MW. Expressed as a percentage, 58.3 MW is 77.7% of the peak shaving magnitude of 75 MW. Table 22 shows the ratios for each of the seven zones in Pennsylvania, as well as a MW-weighted statewide average. The CP impacts are generally larger than the NCP impacts, which makes sense since the 5CP hours for the PJM system as a whole was a key consideration for program design.

Table 22: Peak Demand Forecast Reductions as a Percent of Peak Shaving Size

Zone	EDC	MW	NCP Impact	CP Impact
APS	West Penn Power	75	69.1%	77.7%
ATSI	Penn Power	15	59.0%	13.8%
DUQ	Duquesne Light	50	43.5%	78.0%
METED	Met-Ed	50	25.2%	46.5%
PECO	PECO	150	45.5%	45.8%
PPL	PPL	100	6.0%	70.0%
PN	Penelec	50	37.1%	70.4%
Statewide		**490**	**41.5%**	**60.6%**

Per the 2021 TRC Test Order, the SWE Team used the CP impact values to de-rate the avoided cost of generation capacity values when calculating TRC benefits for each EDC’s Phase IV DR offerings. The behind the meter battery storage analysis in Section 8 does not utilize DR protocols, and values capacity using the full EE avoided cost of generation capacity.

3 PEAK LOAD CONSUMPTION

System peak loads drive the costs of generation capacity and determine the need for future T&D facilities. A successful Act 129 DR program will lower peak forecasts and, as a result, reduce the amount of generation capacity that must be secured by PJM on behalf of the EDCs. Pennsylvania has summer peaking load, and PJM provides summer peak load forecasts for each EDC, as shown in Table 23. PJM is currently modifying the methodology[19] used to forecast peak demand and the new forecast methods are expected to produce slightly lower near-term summer peak demand forecasts[20].

Table 23: Summer Peak Load Forecast (MW) at System Level (e.g., includes losses)

Year	PECO	Duquesne	PPL	Met-Ed	Penelec	Penn Power	WPP	Statewide
2019	8,711	2,862	7,148	2,719	2,379	854	3,620	28,293
2020	8,665	2,852	7,135	2,716	2,372	850	3,623	28,213
2021	8,710	2,853	7,151	2,730	2,367	851	3,724	28,386
2022	8,767	2,865	7,187	2,743	2,372	854	3,756	28,544
2023	8,801	2,866	7,185	2,748	2,372	855	3,768	28,595
2024	8,858	2,870	7,219	2,780	2,376	859	3,793	28,755
2025	8,889	2,870	7,240	2,804	2,378	861	3,810	28,852
2026	8,947	2,879	7,276	2,825	2,385	864	3,823	28,999
2027	8,980	2,883	7,302	2,842	2,382	867	3,837	29,093
2028	9,036	2,888	7,319	2,843	2,387	869	3,853	29,195
2029	9,082	2,887	7,347	2,875	2,388	871	3,868	29,318
2030	9,154	2,896	7,372	2,876	2,395	876	3,888	29,457
2031	9,207	2,901	7,397	2,876	2,399	878	3,907	29,565
2032	9,264	2,911	7,427	2,877	2,402	881	3,922	29,684
2033	9,330	2,917	7,458	2,878	2,406	884	3,941	29,814
2034	9,340	2,920	7,476	2,879	2,408	886	3,952	29,861

While the PJM forecasts are publicly available, their development is not fully transparent. PJM's peak load forecast likely includes some EE program savings and, potentially, the effects of previous DR programs since these details are not incorporated in creating the forecasts. Two important characteristics of these forecasts is that they are at the zonal level and do not distinguish load by sector. PECO, PPL, Met-Ed, Penelec, and Duquesne Light have dedicated PJM zones; however, some adjustments for load served by municipal and cooperative utilities were necessary. West Penn Power and Penn Power are subsets of broader PJM zones, so it was necessary to determine the EDC share of APS and ATSI zone served by these two EDCs. Disaggregation of these summer peak load forecasts to the sector level is an important precursor to the DR potential assessment. Table 24 shows the percentage of the total system load attributed to each customer class. The SWE Team developed these

---

[19] *See* http://insidelines.pjm.com/pjm-proposes-refinements-to-long-term-load-forecasting/.

[20] The 2020 PJM Load Forecast Report was published prior to the release of this DR Potential Study. *See* https://www.pjm.com/-/media/library/reports-notices/load-forecast/2020-load-report.ashx?la=en

percentages using market data available to support the Commonwealth's Electric Generation Suppliers, customer level peak demand data provided by the EDCs in response to the SWE's baseline study data request, and discussions with EDC technical staff.

Table 24: Shares of Peak Load by Sector

EDC	Res	SCI	LCI
PECO	45.75%	18.97%	35.27%
PPL	40.45%	32.82%	26.74%
Duquesne Light	41.24%	25.25%	33.51%
FE: Met-Ed	47.32%	23.64%	29.04%
FE: Penelec	35.87%	29.46%	34.67%
FE: Penn Power	47.04%	30.87%	22.09%
FE: West Penn	41.43%	25.21%	33.37%

By applying the shares associated with C&I customers to the forecasts, the SWE can estimate the SCI and LCI sector peak load for each EDC. It is worth noting that this rests on the assumption that the growth rates are uniform across sector. In other words, any load growth or decline is allocated according to the same percentages. The original Act 129 legislation established Phase I peak demand reduction targets at 4.5% of the average hourly loads for the top 100 hours for the June 1, 2007 to May 31, 2008 delivery year. Table 25 shows the values, by EDC, from that forecast. When DR potential estimates are shown as a percent reduction, the convention in this report is to use the 2007-2008 peak demand values for ease of comparison with prior phases.

Table 25: 2007-2008 Peak Demand Values Used to Establish Phase I Targets

EDC	Peak Demand (MW)
PECO	7,899
PPL	6,592
Duquesne Light	2,518
FE: Met-Ed	2,644
FE: Penelec	2,395
FE: Penn Power	980
FE: WPP	3,496
Statewide Total	**26,524**

4 ECONOMIC ANALYSIS OF DEMAND RESPONSE

Cost-effectiveness analysis in Pennsylvania is performed using the Total Resource Cost (TRC) Test. The SWE Team's assumptions are guided by the technical and policy directives in the 2021 TRC Test Order. These assumptions are summarized in Section 4.1. Assumptions about the supply costs avoided by DR are required to calculate benefits and to model the economics of DR. Section 4.2 provides an overview of the avoided cost assumptions used to model DR potential. Section 4.3 discusses the basis for assumptions about program delivery costs and incentive amounts, and Section 4.4 examines EDC budget considerations.

4.1 USING THE TRC TEST FOR DEMAND RESPONSE

Treatment of incentives is a key assumption when implementing the TRC Test for DR. For EE, incentives are considered a transfer payment and excluded from the TRC costs and benefits. For DR, incentives are considered a proxy for the sacrifice participants make by forgoing the use of electricity. In the 2016 TRC Test Order,[21] the Commission adopted the 75% participant cost assumption set forth in California's 2010 DR Cost-Effectiveness Protocols.[22] This policy directive still considers incentives as a proxy for participant cost, but takes the perspective that customers are generally rational and would likely only participate in a DR program if they felt the benefits of participation outweighed the costs. All economic modeling in this study uses 75% of incentives as TRC cost.

4.2 AVOIDED COSTS

The following sections discuss the financial assumptions used to monetize the grid benefits of DR. Although battery storage is presented in Section 8 of this DR potential study report, the economic modeling perspective is more similar to EE, in that the full avoided cost of generation, transmission, and distribution (GT&D) capacity is used to monetize peak demand reductions.

4.2.1 GENERATION CAPACITY

Generation capacity for Pennsylvania is secured through PJM's forward capacity auction process – the Reliability Pricing Model. BRAs for generation capacity happen approximately three years prior to the beginning of each delivery year. The avoided cost of generation capacity assumptions used to monetize DR impacts are based on the 2021 TRC Test Order and reflect the following steps:

1) For years where the BRA clearing prices are known, the relevant zonal clearing price for each EDC is used.
2) For years where the BRA has not happened yet, the relevant zonal clearing price from the three most recent auctions are escalated for inflation and averaged to establish a forecast starting point.

---

[21] *See* the *Final 2016 TRC Test Order*, Docket No. M-2015-2468992 (entered June 22, 2015) at http://www.puc.pa.gov/pcdocs/1367195.docx.

[22] *See* http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm.

3) The avoided cost of generation capacity is then de-rated for DR based on the expected forecast reduction per MW of PSA. The values shown in Table 26 are used for de-rating and come from Pennsylvania-specific modeling conducted by PJM.
4) A value of $/kW-year is used for delivery years where the BRA occurs prior to the development of Phase IV EE&C Plans. Although PSAs could potentially be nominated in incremental auctions, it is likely that the value would be significantly lower, so the SWE Team elected to use conservative modeling assumptions.

Table 26: Peak Shaving Adjustment Factors, by EDC

EDC	Multiplier
PECO	45.8%
PPL	70.4%
Duquesne Light	78.0%
FE: Met-Ed	46.5%
FE: Penelec	70.0%
FE: Penn Power	13.8%
FE: West Penn Power	77.7%

Table 27 shows the avoided cost of generation capacity assumptions used to model DR benefits, by EDC, inclusive of the EDC-specific adjustment factors presented in Table 26.

Table 27: Avoided Cost of Generation Capacity Forecast, by EDC (nominal $/kW-year)

Year	EDC						
	DLC	PECO	PPL	ME	PN	PP	WPP
PY13 (2021-2022)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
PY14 (2022-2023)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
PY15 (2023-2024)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
PY16 (2024-2025)	$32.44	$28.53	$30.15	$19.90	$29.99	$6.32	$33.31
PY17 (2025-2026)	$33.09	$29.10	$30.76	$20.30	$30.59	$6.44	$33.97

4.2.2 TRANSMISSION AND DISTRIBUTION CAPACITY

EDC transmission and distribution infrastructure must be sized to meet peak load requirements, so the 2021 TRC Test Order assumes that peak demand reductions from EE and DR have the ability to avoid or defer load-growth related capital investments. The SWE Team developed separate avoided transmission and avoided distribution cost forecasts for each EDC using five-year forecasts of load-growth related capital expenditures provided by EDC system planners. No avoided cost of distribution capacity is assigned to LCI customers that take service at primary voltage because these customers largely bypass the EDC distribution system and maintain their own transformers. Like the avoided cost of generation capacity, the avoided transmission and distribution benefits from DR are de-rated compared to EE (or batteries). Per the 2021 TRC Test Order, a common de-rate value of 60% was used for all EDCs. Table 28 shows the avoided cost of transmission capacity forecast by EDC, and Table 29 presents the distribution values.

Table 28: Avoided Cost of Transmission Capacity Forecast, by EDC ($/kW-year)

Year	EDC						
	DLC	PECO	PPL	ME	PN	PP	WPP
PY13 (2021-2022)	$18.76	$14.97	$0.00	$15.05	$18.25	$0.00	$0.10
PY14 (2022-2023)	$19.14	$15.27	$0.00	$15.35	$18.61	$0.00	$0.10
PY15 (2023-2024)	$19.52	$15.58	$0.00	$15.65	$18.98	$0.00	$0.10
PY16 (2024-2025)	$19.91	$15.89	$0.00	$15.97	$19.36	$0.00	$0.11
PY17 (2025-2026)	$20.31	$16.21	$0.00	$16.29	$19.75	$0.00	$0.11

Table 29: Avoided Cost of Distribution Capacity Forecast, by EDC ($/kW-year)

Year	EDC						
	DLC	PECO	PPL	ME	PN	PP	WPP
PY13 (2021-2022)	$9.78	$63.49	$72.73	$42.03	$27.65	$11.43	$14.03
PY14 (2022-2023)	$9.97	$64.76	$74.18	$42.87	$28.20	$11.66	$14.31
PY15 (2023-2024)	$10.17	$66.05	$75.67	$43.73	$28.77	$11.89	$14.60
PY16 (2024-2025)	$10.38	$67.37	$77.18	$44.60	$29.34	$12.13	$14.89
PY17 (2025-2026)	$10.58	$68.72	$78.72	$45.49	$29.93	$12.37	$15.19

4.2.3 ENERGY

The DR strategies examined in this report are assumed to be energy neutral in that the reduced energy consumption during DR event hours is offset by increased energy usage outside of the DR event hours. To monetize this shift in consumption timing, the SWE Team calculated the differential between the “summer on-peak” and “summer off-peak” avoided cost of electric energy forecast by EDC and year. The cost differential values shown in Table 30 are multiplied by the estimated demand reduction and the assumed number of event hours to calculate the energy benefits of DR.

Table 30: Avoided Energy Cost Forecast, by EDC (Nominal $/MWh)

Year	EDC						
	DLC	PECO	PPL	ME	PN	PP	WPP
PY13 (2021-2022)	$11.99	$11.27	$11.24	$11.63	$11.64	$11.64	$11.64
PY14 (2022-2023)	$11.41	$10.72	$10.70	$11.07	$11.07	$11.07	$11.07
PY15 (2023-2024)	$12.02	$11.30	$11.27	$11.67	$11.67	$11.67	$11.67
PY16 (2024-2025)	$12.16	$11.43	$11.41	$11.80	$11.81	$11.81	$11.81
PY17 (2025-2026)	$12.94	$12.20	$12.17	$12.56	$12.59	$12.59	$12.59

4.2.4 WHOLESALE PRICE SUPPRESSION

Consistent with prior Act 129 DR potential studies and the 2021 TRC Test Order, this study does not assign any benefits to wholesale price suppression. Wholesale price suppression, or Demand Reduction Induced Price Effects (DRIPE), occurs when reduced demand lowers the market clearing price and thus reduces the cost of the remaining capacity purchased in the market. If Act 129 Phase IV DR programs are nominated to PJM as PSAs, the demand curve will shift left and potentially result in a lower clearing price in the BRA. If the clearing price is lower, there are savings associated with purchasing capacity for all market participants. However, in practice, the supply curve is not necessarily a smooth function but rather imitates a *staircase* composed of horizontal and vertical segments. Consequently, there is no guarantee a PSA nomination will lower the clearing price. The SWE understands that PJM does not intend to run BRAs with and without PSAs, so the extent of any price suppression will be unknown. While price suppression effects are based on sound economic theory, the Commission and stakeholders have significant concerns regarding the inherent uncertainty associated with quantifying this benefit stream as a TRC benefit; therefore, the Commission excluded it from the 2021 TRC Test Order. Consequently, the SWE did not include any price suppression benefits in this study.

4.3 PROGRAM DELIVERY AND INCENTIVE COSTS

Modeling assumptions about the fixed and volumetric costs of delivering DR programs are documented in the strategy-specific chapters of this report. Generally, the SWE Team relied on Pennsylvania-specific data, where available and applicable, and supplemented with cost assumptions from other jurisdictions where necessary. The underlying avoided costs used in the DR and EE market potential studies are identical. For new installation of connected thermostats, which produce EE savings and benefits in addition to DR, the DR study team aligned incremental cost, energy savings, load shape, and heating system saturation values with the EE market potential study.

4.4 EDC PROGRAM BUDGETS

Pennsylvania's Act 129 EE&C programs are budget constrained, with each EDC's funding capped at 2% of 2006 revenues.[23] Table 31 shows the Phase IV funding amounts by EDC, as well as an estimate of annual budget. The annual budget is simply the five-year budget divided by five.

Table 31: Phase IV Funding Limits, by EDC

Full Name	Five-Year EE&C Funding (Million $)	Annual Budget (Million $)
PECO	$427.39	$85.48
PPL	$307.51	$61.50
Duquesne Light	$97.73	$19.55
FE: Met-Ed	$124.33	$24.87
FE: Penelec	$114.87	$22.97
FE: Penn Power	$33.30	$6.66
FE: West Penn	$117.81	$23.56
Statewide	**$1,222.94**	**$244.59**

In addition to the cost-effectiveness results, such as TRC benefits, TRC costs, and TRC net benefits, this report presents estimates of the EDC budget requirement to deliver DR programs. EE&C plans are funded and recovered in nominal dollars, so estimates of EDC budget requirements are presented in nominal dollars. For reference, the SWE expressed the modeled EDC expenditure in both dollars and as a percentage of EE&C funding. This spending percentage is EDC program expenditures divided by the funding limits show in Table 31.

The SWE Team's models also calculate the acquisition cost of DR strategies on a $/kW-year basis. The acquisition cost of DR is an important metric for examining the EDC budget requirements to meet possible Phase IV DR targets. If the acquisition cost of DR is $90/kW-year, the budget requirement for an EDC with a 10 MW DR target for each of the five years of Phase IV would be calculated as follows:

$$Budget\ Requirement = Target\ kW * Years * Acquisition\ Cost$$

$$Budget\ Requirement = 10{,}000 * 5 * \$90$$

$$Budget\ Requirement = \$4{,}500{,}000$$

Under Act 129, each EDC has a capped EE&C plan budget, so every dollar spent on DR is a dollar that cannot be used to meet EE goals and vice versa[24]. The companion Phase IV Energy Efficiency Potential Study report compares the economic efficiency of an all EE scenario with an EE/DR funding split scenario.

---

[23] *See* House Bill No. 2200 of the General Assembly of Pennsylvania, An Act Amending Title 66 (Public Utilities) of the Pennsylvania Consolidated Statutes, page 59.

[24] As discussed in Section 5, EDC installation of connected thermostats can provide both energy savings (kWh) and demand response capability.

5 CONNECTED THERMOSTATS

Residential air conditioning load is one of the primary drivers of system peaking conditions in Pennsylvania. On hot summer afternoons, electric loads from the Commonwealth's approximately 2.5 million residential central air conditioners ramp up to maintain comfortable indoor temperatures. Reductions in residential cooling load can provide substantial amounts of DR, as 1-2 kW of reduction is aggregated over thousands or tens of thousands of customers on hot event days. Utility direct load control of central air conditioners has been commonplace in North America for the last 30 years. However, in recent years, the technology has evolved from cycling switches mounted outside the home to Wi-Fi connected thermostats inside the home.

Wi-Fi connected "smart" thermostats offer multiple advantages compared to traditional direct load control equipment.

1) Thermostats are a required part of any CAC system, as opposed to a supplemental device installed exclusively for the purpose of DR.
2) Connected thermostats are an attractive consumer product. Many homeowners buy and install these devices absent any utility incentive because of the convenience and control they offer over the heating and cooling systems. This can reduce program costs because the EDC does not have to pay for the equipment and installation. Unlike a traditional direct load control switch, the thermostat itself can be viewed as a thing of value, or incentive, to participants.
3) Connected thermostats can be self-installed by participants and do not require a technician to install the device. However, some homeowners prefer to have the installation performed by a professional.
4) Connected thermostats offer two-way communication with the program administrator. This allows improved visibility into operability, participant opt-outs, and load impacts.

Even though there are advantages to traditional load control switches, most new utility residential DR programs utilize connected thermostats and many programs are converting legacy load control switches to connected thermostats. The SWE Team modeled DR of residential air conditioning for two types of connected thermostat offerings:

- **A Bring-Your-Own-Thermostat (BYOT) program**: current owners of Wi-Fi connected thermostats are offered financial incentives in exchange for allowing the EDC or it's CSP to modify the cooling setpoint during DR events.

- **A "New Install" Connected Thermostat program**: the EDC subsidizes all or a portion of the cost of the upfront equipment and installation cost of the thermostat in exchange for the ability to control loads on event days.

To the extent possible, information specific to each EDC's territory was used. Our modeling assumes targeting of participants based on economics. While the measures would be available to any residential customer with CAC, the SWE assumed that EDCs would leverage AMI data or connected thermostat runtime data to target program marketing to those accounts with the largest air conditioning loads during typical DR hours. Enrollment, benefits, and costs are calculated for two scenarios: MAP, which enrolls all eligible customers as long as the offering remains cost-effective in aggregate, and RAP, which enrolls only customers who have a positive marginal benefit. The following sections discuss this in more detail, but the intuition is straightforward: not all customers are average. Some have larger homes and use more air conditioning than others. Larger customers are generally able to provide larger load reductions and consequently provide more avoided capacity benefits for the same per-customer cost.

Connected thermostat DR offerings are modeled for each summer of Phase IV. The following sections explore the avoided costs and other key assumptions in more detail.

5.1 ASSUMPTIONS USED

The key factors affecting the cost-effectiveness and potential of the connected thermostat offerings can be grouped in to five main categories:

1) The **number of customers enrolled** in each program by year: enrollment has a bearing on aggregate benefits and whether the program is cost-effective when including overhead costs.
2) The amount of **load reduction** offered by a participant (kW): the more load reduction offered, the more valuable that participant is.
3) The **avoided capacity** and energy costs: Avoided GT&D capacity costs depend on the system infrastructure and peak characteristics of each EDC. Avoided energy costs are the difference between summer on-peak and off-peak energy prices, assuming that DR events are energy neutral and customers simply shift consumption from on-peak periods to off-peak periods. For the new installation offering, the annual energy savings, as characterized in the 2021 Pennsylvania TRM, are included in the calculation of benefits. The incremental annual kWh savings from new thermostat installations are also included in the EE totals for any EE/DR funding split scenario that includes DR.
4) The **fixed and variable costs** of the program: Fixed costs do not depend on the size of the program, while variable costs are incurred on a per-participant basis. The variable costs must be less than per-customer benefits in order to make the program cost-effective at the margin. Our modeling uses participants and devices somewhat interchangeably as most homes have one thermostat. Some large homes have more than one thermostat, in which case the variable costs would be more precisely described as per-device.
5) Key **financial assumptions**, such as the discount rate and the percentage of incentive costs that are to be counted as TRC costs.

Items 3 and 5 were included in a general discussion of statewide economic assumptions in Section 4, so this section details the program-specific assumptions required to model DR potential for connected thermostats.

5.1.1 ENROLLMENTS

Our modeling approach for connected thermostats first considers the possible enrollment levels given the saturation of households with CAC, by EDC, and assumed incentive level. These enrollment limits are later broken into deciles of cooling load and subjected to the MAP and RAP economic screening, which can lower the ultimate program participation assumptions. Two of the SWE Team's key foundational assumptions are the number of residential households in each EDC, and the percentage of those households with CAC. Table 32 shows the values drawn from the 2018 Pennsylvania Residential Baseline Study.[25]

Table 32: Candidate Households, by EDC

EDC	Residential Households	Percent of Households with Central AC	Candidate Households
PECO	1,463,000	54%	790,020
PPL	1,247,000	31%	386,570
Duquesne Light	533,000	49%	261,170
FE: Met-Ed	499,000	66%	329,340
FE: Penelec	498,000	29%	144,420
FE: Penn Power	144,000	74%	106,560
FE: West Penn	625,000	54%	337,500

BYOT enrollment limits are shown in Table 33 and assume that 1 in 15 households[26] purchases a new thermostat in any given year. The smart thermostat market share of new purchases grows in an S-shaped curve over time, with a cap of 70%. Based on observed enrollment rates in other BYOT programs in the US, the SWE Team assumed that 10% of the households with a smart thermostat would enroll in the BYOT program, if offered. For the New Install program, the SWE assumed that 5% of households with Central AC that do not already have a connected thermostat would enroll after an initial marketing campaign early in Phase IV. No further recruitment was assumed, and attrition in the program over time would be 5% per year.

---

[25] *See* 2018 Pennsylvania Statewide Act 129 Residential Baseline Study at http://www.puc.state.pa.us/Electric/pdf/Act129/SWE-Phase3_Res_Baseline_Study_Rpt021219.pdf, Table 6 (households) and Table 217 (Percent with Central AC).

[26] The Pennsylvania TRM has a measure life cap of 15 years, so the SWE assumed 1 in 15 thermostats are replaced each year. Additionally, since most thermostats get replaced when the household HVAC system is replaced, we can look to the measure life of furnaces, AC units, and heat pumps, which all have measure lives of 15 years per the PA TRM.

Table 33: BYOT Enrollment Limits

PY Start	PECO	PPL	Duquesne Light	FE: Met-Ed	FE: Penelec	FE: Penn Power	FE: West Penn
2021	6,721	5,413	2,419	2,358	2,151	693	2,871
2022	7,965	6,022	2,830	2,877	2,378	861	3,402
2023	9,632	6,838	3,382	3,572	2,683	1,086	4,115
2024	11,739	7,868	4,078	4,450	3,068	1,370	5,015
2025	14,262	9,103	4,912	5,502	3,529	1,710	6,093

Table 34: New Thermostat Installation Enrollment Limits

PY Start	PECO	PPL	Duquesne Light	FE: Met-Ed	FE: Penelec	FE: Penn Power	FE: West Penn
2021	39,165	19,058	12,938	16,349	7,113	5,293	16,731
2022	37,207	18,105	12,291	15,532	6,758	5,029	15,895
2023	35,346	17,200	11,676	14,755	6,420	4,777	15,100
2024	33,579	16,340	11,092	14,017	6,099	4,538	14,345
2025	31,900	15,523	10,538	13,316	5,794	4,311	13,628

It is worth noting that PECO currently has over 50,000 residential households in its Smart AC direct load control program. The SWE did not exclude these homes from the PECO forecast or make any implicit assumptions that those homes would be converted to a smart thermostat. Programmatically speaking, the Smart AC program equipment will be over ten years old at the beginning of Phase IV, so PECO may elect to contact participants with an offer to convert the legacy equipment to a new smart thermostat. PECO could also continue to operate the legacy Smart AC infrastructure, but the Phase III acquisition cost has been close to $200/kW-year, which is higher than the connected thermostat options modeled in this report.

5.1.2 LOAD REDUCTIONS

For the connected thermostat programs, the SWE completed an analysis using Ecobee's Donate Your Data initiative,[27] where cooling loads on hot summer days were assessed for customers in Pennsylvania and surrounding states (New York, Ohio, Connecticut, New Jersey, Maryland, West Virginia, and Delaware). Approximately 9,000 thermostats were included. Ten deciles of cooling loads, grouped by weather sensitivity, were delineated and used to provide some measure of sensitivity analysis for the resulting cost-effectiveness screening. As the EDCs have residential AMI data available, they can easily perform a similar analysis by comparing load profiles on hot summer days to mild days when limited heating or cooling would be required. The difference between these two profiles is a proxy for the cooling load in the home, and homes could be ranked by typical cooling load. Based on findings from

---

[27] *See* https://www.ecobee.com/donateyourdata/.

evaluations conducted in other jurisdictions, the SWE assumed that, when dispatched, cooling loads could be reduced by 70% per customer for a three-hour event.

Table 35 :Per-Device Cooling Loads Available for Curtailment

Decile	Peak Day Cooling Load (kW)	Load Impact (kW)
Top 10%	2.11	1.48
10-20%	1.92	1.35
20-30%	1.81	1.27
30-40%	1.69	1.18
40-50%	1.55	1.08
50-60%	1.46	1.02
60-70%	1.32	0.93
70-80%	1.13	0.79
80-90%	0.91	0.64
Bottom 10%	0.53	0.37

Our model investigates two separate scenarios, analogous to maximum achievable and realistic achievable DR potential. In the MAP perspective, as many deciles as possible are targeted as long as the program is cost-effective as a whole. The RAP perspective only targets deciles that are cost-effective independently.

5.1.3 ENERGY-EFFICIENCY BENEFITS FROM NEW THERMOSTAT INSTALLATIONS

In addition to the capacity benefits associated with peak demand reductions, connected thermostats also save heating and cooling energy by operating residential HVAC systems more efficiently compared to manual thermostats or conventional programmable thermostats. The TRC benefits of EE savings are between $225 and $267 (2021$) over the expected 11-year lifespan of the thermostat, depending on the EDC.

The SWE Team relied on the 2021 TRM[28] and the 2018 Pennsylvania Statewide Act 129 Residential Baseline Study[29] to calculate the annual electricity and natural gas savings per thermostat for each EDC. Electricity and natural gas savings vary across EDCs because different HVAC system types save different amounts of electricity and natural gas, and because each EDC has a different composition of HVAC system types.

---

[28] *See* the 2021 TRM, Volume 2 – Residential Measures, pages 47-53, at http://www.puc.pa.gov/pcdocs/1630968.docx

[29] *See* the 2018 Pennsylvania Residential Baseline Study at http://www.puc.pa.gov/Electric/pdf/Act129/SWE-Phase3_Res_Baseline_Study_Rpt021219.pdf.

The SWE Team used default electric savings assumptions from the ENERGY STAR Connected Thermostats protocol[30] in the 2021 TRM. The TRM algorithms reflect savings for multiple combinations of HVAC system type. They reflect whether the thermostat was installed by the customer directly or by a professional. The SWE assumed savings are consistent with the "Customer Self-Installation with Education" program type since the EDC is supporting the new thermostat installation and has a degree of control over the installation process. Annual savings are different for each of the three HVAC system types:

1) Air source heat pump (ASHP) with electric auxiliary heat
2) CAC with an electric furnace
3) CAC with a natural gas furnace

For each EDC, the SWE Team calculated a weighted average savings based on the HVAC system shares for that EDC. HVAC system shares were calculated using the 2018 Pennsylvania Statewide Act 129 Residential Baseline Study, which provides data on HVAC system by fuel type (e.g., electric, gas) and by equipment type (e.g., furnace, boiler, ASHP).[31]

The SWE Team assumption for natural gas savings is 48.1 therms per thermostat, based on default values for furnace capacity, equivalent full load hours (EFLH), and energy savings factor (ESF) listed in the 2021 TRM. Natural gas savings accrue with only one of the three HVAC system types – households with CAC and a natural gas furnace – so the weighted average savings per EDC is simply the share of households with natural gas furnaces multiplied by 48.1.

The SWE Team multiplied the annual natural gas savings by 1.04167 to account for system losses and then multiplied them by the Phase IV projected avoided cost of natural gas price for each year in the 11-year expected lifetime starting in PY13. The SWE then converted the lifetime savings to net present value in 2021$ using a 5% nominal discount rate.

---

[30] *See* the 2021 TRM, Volume 2 – Residential Measures, pages 51-52 at http://www.puc.pa.gov/pcdocs/1630968.docx.

[31] The SWE relied on values from Tables 201 and 202, because Table 202 did not distinguish between electric furnaces and natural gas furnaces – but the TRM EE savings differ depending on whether the house uses an electric or natural gas furnace – the SWE Team had to derive the percentage of electric furnaces. This value was calculated by subtracting the share of devices in Table 202 that use electricity but are not furnaces (i.e., ASHP, Baseboard, DHP, PTAC, and GSHP) from the share of houses that use electricity as their primary heating fuel (as listed in Table 201). For instance, PPL had a total share of non-furnace electric devices of 29% in Table 202 and an electric fuel share of 36% in Table 201. The SWE assumed that the difference between the two numbers (6.9%) was the share of households with CAC with electric furnaces. The remaining portion of furnaces were assumed to be natural gas and assigned to the CAC with natural gas furnace HVAC system category, along with fossil fuel boilers.

The calculation for electric savings is more complex because the SWE Team assumed the avoided cost of electricity differs across six costing periods within each year. The value of energy savings depends on the load shape and how savings are distributed across costing periods. The SWE Team aligned savings load shapes with the EE potential study assumptions for each of the three HVAC system types to calculate time-differentiated energy savings. The SWE Team multiplied the resulting value by EDC-specific residential line loss factors to calculate the total resource savings.[32] As with natural gas savings, the SWE Team then converted lifetime savings to net present value in 2021$ using a 5% nominal discount rate.

The table below shows the major assumptions and the benefits in 2021$ for each thermostat. Total savings range from $225 to $267, with natural gas savings being higher than electricity savings for five of the seven EDCs.

Table 36: Energy-Efficiency Benefits Summary for New Thermostat Installs

EDC	HVAC System Share by EDC			Per-Device Savings at Meter		Per-Device TRC Benefits (2021$)		
	ASHP w/ Electric Aux Heat	CAC w/ Electric Furnace	CAC w/ Gas Furnace	Electric (kWh)	Gas (therms)	Electric	Gas	Total
PECO	14.3%	0.0%	85.7%	243.7	41.3	$88	$137	$225
PPL	13.2%	10.3%	76.5%	387.1	36.8	$142	$122	$264
Duquesne Light	2.4%	4.7%	92.9%	258.0	44.7	$97	$147	$244
FE: Met-Ed	11.5%	6.9%	81.6%	330.4	39.3	$124	$130	$254
FE: Penelec	0.0%	0.0%	100.0%	179.7	48.1	$67	$158	$225
FE: Penn Power	9.3%	10.3%	80.4%	369.6	38.7	$140	$127	$267
FE: West Penn	18.5%	2.5%	79.0%	298.1	38.0	$113	$125	$238

5.1.4 Program Costs

The SWE Team organized the connected thermostat program into three categories for modeling. The cost values listed below are for 2021. An annual inflation rate of 2% was applied to calculate program budget requirements in the years 2022-2025.

1) **Fixed program administration**: certain aspects of program delivery are independent of program size. There is some minimum level of EDC staffing, CSP set-up fees, tracking system integration, and EM&V costs that are required no matter how small a program is. The SWE assumed any connected thermostat offering will require $20,000 of fixed program administration cost annually. Fixed program costs are more challenging to overcome for a small EDC than a large EDC.

2) **Variable program administration**: other aspects of program delivery scale proportionately with program size. Connected thermostat manufacturers generally assess Application Programming Interface (API) fees on a per-device basis. Marketing costs and CSPs' fees have an approximately linear relationship with the number of program participants. The SWE Team

---

[32] Line loss factors were obtained from Table 1-4 of the 2021 TRM and range from 7.4-9.5%.

assumed $35 per device of recurring annual cost for both the BYOT and New Install offering. For the New Install offering, the SWE also assumed that 50% of participants will prefer professional installation, and the one-time labor cost to install the thermostat is $75. For BYOT, there is no device cost because the program targets homes that have already installed a connected thermostat. For the New Install offering, the cost of the thermostat is a program cost and an incremental measure cost in the TRC Test. Our model assumes an equipment cost of $175 per thermostat.

3) **Incentives**: participant incentives are also a volumetric cost category. From an EDC budget or acquisition cost perspective, incentives are no different from the delivery costs discussed above. However, in the TRC calculations, only 75% of incentives are treated as cost. The 2021 TRC Test Order states that directly installed equipment costs be treated as incremental measure cost and incentives. Although the thermostat is an incentive, the spirit of the DR incentive perspective in the Pennsylvania TRC Test is that incentives are a proxy for participant cost (discomfort from less AC usage on a hot day), so our model assumes an $175*0.75 = $131.25 TRC cost per thermostat during the installation year for new thermostat installations.

The fixed costs of the thermostat programs are based on cost benchmarking of budget filings for similar programs offered by investor-owned utilities in the United States. The SWE Team found that most program plans have a relatively low fixed administrative overhead, with the bulk of program costs scaling linearly with the expected number of participants. Although the fixed cost assumptions used to model connected thermostat potential are modest relative to the variable cost components, two simplifying assumptions are worth noting:

- Fixed costs for each of the four FirstEnergy EDCs have been treated as independent of one another, even though FirstEnergy would likely leverage economies of scale across its four Pennsylvania EDCs.
- The SWE treated BYOT and New Install offerings as separate programs with distinct fixed costs. An EDC that implements both thermostat offerings might experience some cost savings relative to the sum of two fixed cost totals.

For customers in a BYOT program, the EDC is assumed to pay an annual incentive of $50 to the enrolled customers in exchange for allowing the EDC to reduce AC loads via the connected thermostat on DR days. In the New Install thermostat program, the EDC subsidizes the upfront cost of the thermostat without any recurring incentives. This makes the cost profile of the New Install program more front-loaded than the BYOT program.

5.2 RESULTS

The connected thermostat modeling includes two types of programs (BYOT and New Install) and two economic perspectives (Realistic Achievable and Maximum Achievable). This section is organized by EDC, with a dedicated sub-section showing the different results for each EDC. The New Thermostat Installation tables have an additional row that shows the EE savings (MWh/year) attributable to the annual electric energy savings an EDC could claim by supporting installation of a new ENERGY STAR connected thermostat.

5.2.1 PECO

Table 37 shows the RAP BYOT results for PECO. Table 38 shows the MAP results. The RAP results include only the top seven deciles of AC users, while the MAP results include all ten deciles. The inclusion of the deciles of homes that are not marginally cost-effective increases the overall BYOT potential to 10.9 MW, compared to 9.0 MW for RAP. However, the TRC ratio for MAP is lower, at 1.21, compared to 1.40 for RAP. The MAP acquisition cost on a $/kW-year basis is also higher than the RAP model, which focuses program marketing on larger households. Throughout this section acquisition costs are calculated prior to rounding the system level MW estimates. Dividing the spending values by rounded MW values may return slightly different values.

Table 37: PECO BYOT Results - RAP

Metric	2021	2022	2023	2024	2025	Phase IV
System Level MW	6.0	7.1	8.6	10.5	12.7	9.0
Spend (Nominal $)	$419,911	$503,767	$617,055	$762,418	$940,170	$3,243,322
TRC Benefits (PV 2021$)	$424,732	$488,530	$573,653	$910,306	$1,073,882	$3,471,104
TRC Costs (PV 2021$)	$361,101	$411,845	$479,608	$563,481	$660,840	$2,476,875
TRC Net Benefits (PV 2021$)	$63,631	$76,686	$94,046	$346,825	$413,042	$994,230
Acquisition Cost (Nominal $/kW)	$70.06	$70.92	$71.84	$72.83	$73.92	$72.28
Nominal Spend % of DSM Budget	0.49%	0.59%	0.72%	0.89%	1.10%	0.76%

Table 38: PECO BYOT Results - MAP

Metric	2021	2022	2023	2024	2025	Phase IV
System Level MW	7.3	8.6	10.4	12.7	15.5	10.9
Spend (Nominal $)	$591,302	$710,925	$872,590	$1,080,072	$1,333,822	$4,588,711
TRC Benefits (PV 2021$)	$516,612	$594,211	$697,748	$1,107,226	$1,306,188	$4,221,984
TRC Costs (PV 2021$)	$507,287	$580,028	$677,074	$797,129	$936,442	$3,497,960
TRC Net Benefits (PV 2021$)	$9,325	$14,183	$20,673	$310,097	$369,746	$724,024
Acquisition Cost (Nominal $/kW)	$81.10	$82.29	$83.52	$84.82	$86.22	$84.07
Nominal Spend % of DSM Budget	0.69%	0.83%	1.02%	1.26%	1.56%	1.07%

Table 39 shows the RAP results for a PECO New Install program. Table 40 shows the MAP results. Unlike the BYOT program, which shows program cost and TRC metrics over each year of Phase IV, the costs of a New Install program are front-loaded in 2021 when the thermostat installations are assumed to occur. The EE benefits, which accrue to the installation year, help offset things from a TRC standpoint, but the program still returns a TRC ratio of less than 1.0 in 2021. The TRC ratio for Phase IV as a whole is 1.29 for the RAP scenario and 1.20 for the MAP scenario. Implementing the New Install RAP scenario would require approximately 4% of PECO's Phase IV EE&C budget, and the MAP scenario would require approximately 5%.

Table 39: PECO New Thermostat Installation - RAP

Metric	2021	2022	2023	2024	2025	Phase IV
Meter Level MWh/year (EE)	7,634					7,634
System Level MW	38.2	36.3	34.5	32.8	31.2	34.6
Spend (Nominal $)	$13,257,750	$1,083,023	$1,050,490	$1,018,986	$988,480	$17,398,728
TRC Benefits (PV 2021$)	$9,745,712	$2,499,094	$2,305,236	$2,851,491	$2,630,312	$20,031,846
TRC Costs (PV 2021$)	$11,886,977	$1,030,862	$951,737	$878,731	$811,369	$15,559,675
TRC Net Benefits (PV 2021$)	($2,141,265)	$1,468,233	$1,353,499	$1,972,760	$1,818,944	$4,472,170
Acquisition Cost (Nominal $/kW)	$346.63	$29.81	$30.43	$31.07	$31.73	$100.54
Nominal Spend % of DSM Budget	15.53%	1.27%	1.23%	1.19%	1.16%	4.07%

Table 40: PECO New Thermostat Installation - MAP

Metric	2021	2022	2023	2024	2025	Phase IV
Meter Level MWh/year (EE)	9,543					9,543
System Level MW	42.5	40.4	38.3	36.4	34.6	38.4
Spend (Nominal $)	$16,567,187	$1,348,679	$1,307,910	$1,268,426	$1,230,187	$21,722,390
TRC Benefits (PV 2021$)	$11,804,765	$2,775,884	$2,560,555	$3,167,310	$2,921,635	$23,230,148
TRC Costs (PV 2021$)	$14,853,721	$1,283,723	$1,184,959	$1,093,838	$1,009,768	$19,426,009
TRC Net Benefits (PV 2021$)	($3,048,956)	$1,492,161	$1,375,596	$2,073,472	$1,911,867	$3,804,139
Acquisition Cost (Nominal $/kW)	$389.97	$33.42	$34.11	$34.82	$35.55	$113.01
Nominal Spend % of DSM Budget	19.40%	1.58%	1.53%	1.49%	1.44%	5.09%

5.2.2 PPL

Table 41 shows the RAP BYOT results for PPL. Table 42 shows the MAP BYOT results. The TRC ratio for the RAP scenario is 1.31, and the MAP scenario has a TRC ratio of 1.14. The MW potential of both scenarios grow steadily over time as the number of connected thermostats installed in the PPL service territory is assumed to increase. The acquisition cost estimates for PPL are similar to PECO, at $72/kW-year in the RAP modeling scenario and $83/kW-year in the MAP modeling scenario. Throughout this section acquisition costs are calculated prior to rounding the system level MW estimates. Dividing the spending values by rounded MW values may return slightly different values.

Table 41: PPL BYOT Results - RAP

Metric	2021	2022	2023	2024	2025	Phase IV
System Level MW	4.9	5.5	6.2	7.2	8.3	6.4
Spend (Nominal $)	$342,092	$385,857	$444,078	$518,049	$607,925	$2,298,001
TRC Benefits (PV 2021$)	$323,185	$348,950	$384,730	$597,196	$670,858	$2,324,919
TRC Costs (PV 2021$)	$294,726	$316,118	$345,937	$383,738	$428,231	$1,768,749
TRC Net Benefits (PV 2021$)	$28,460	$32,832	$38,793	$213,458	$242,627	$556,169
Acquisition Cost (Nominal $/kW)	$69.54	$70.51	$71.47	$72.45	$73.49	$71.75
Nominal Spend % of DSM Budget	0.56%	0.63%	0.72%	0.84%	0.99%	0.75%

Table 42: PPL BYOT Results - MAP

Metric	2021	2022	2023	2024	2025	Phase IV
System Level MW	6.0	6.7	7.6	8.7	10.1	7.8
Spend (Nominal $)	$480,132	$542,481	$625,479	$730,973	$859,187	$3,238,252
TRC Benefits (PV 2021$)	$393,098	$424,435	$467,956	$726,383	$815,980	$2,827,853
TRC Costs (PV 2021$)	$412,465	$443,275	$486,117	$540,352	$604,143	$2,486,353
TRC Net Benefits (PV 2021$)	($19,367)	($18,839)	($18,161)	$186,031	$211,837	$341,500
Acquisition Cost (Nominal $/kW)	$80.24	$81.50	$82.76	$84.05	$85.39	$83.13
Nominal Spend % of DSM Budget	0.78%	0.88%	1.02%	1.19%	1.40%	1.05%

Table 43 shows the RAP results for a PPL program designed to install new connected thermostats. Table 44 shows the MAP modeling outputs. The RAP scenario includes the top eight deciles of AC users, while the MAP scenario includes all ten deciles. The acquisition cost of the New Install program model is $27-$28 more per kW-year than the BYOT program offering, but the MW potential is higher, and the New Install program offering contributes 5,902 (RAP) and 7,377 (MAP) MWh/year of incremental annual energy savings that could be used toward a Phase IV consumption reduction target. The TRC ratios of the BYOT and New Install program designs are similar for PPL and PECO.

Table 43: PPL New Thermostat Installation - RAP

Metric	2021	2022	2023	2024	2025	Phase IV
Meter Level MWh/year (EE)	5,902					5,902
System Level MW	19.0	18.0	17.1	16.3	15.4	17.2
Spend (Nominal $)	$6,461,548	$537,477	$521,856	$506,739	$492,113	$8,519,733
TRC Benefits (PV 2021$)	$5,264,838	$1,148,871	$1,059,760	$1,358,020	$1,252,690	$10,084,179
TRC Costs (PV 2021$)	$5,794,524	$511,591	$472,798	$436,991	$403,938	$7,619,842
TRC Net Benefits (PV 2021$)	($529,686)	$637,280	$586,962	$921,029	$848,752	$2,464,337
Acquisition Cost (Nominal $/kW)	$340.71	$29.83	$30.49	$31.17	$31.86	$99.29
Nominal Spend % of DSM Budget	10.51%	0.87%	0.85%	0.82%	0.80%	2.77%

Table 44: PPL New Thermostat Installation - MAP

Metric	2021	2022	2023	2024	2025	Phase IV
Meter Level MWh/year (EE)	7,377					7,377
System Level MW	21.1	20.0	19.0	18.1	17.2	19.1
Spend (Nominal $)	$8,071,935	$666,746	$647,118	$628,118	$609,729	$10,623,646
TRC Benefits (PV 2021$)	$6,407,559	$1,276,115	$1,177,135	$1,508,429	$1,391,433	$11,760,670
TRC Costs (PV 2021$)	$7,238,155	$634,634	$586,285	$541,663	$500,481	$9,501,217
TRC Net Benefits (PV 2021$)	($830,596)	$641,481	$590,850	$966,765	$890,952	$2,259,453
Acquisition Cost (Nominal $/kW)	$383.19	$33.32	$34.04	$34.78	$35.54	$111.47
Nominal Spend % of DSM Budget	13.12%	1.08%	1.05%	1.02%	0.99%	3.45%

5.2.3 DUQUESNE LIGHT

Neither the BYOT nor the New Install connected thermostat offerings are cost-effective for Duquesne Light, so the RAP and MAP results are 0 MW for both program design types. The challenge for EDCs without high avoided T&D benefits is fixed program costs. If just one or two deciles have positive marginal benefits on a per-thermostat basis, the thermostats in those deciles shoulder the full fixed program administration cost of $20,000 per year. For BYOT, each decile is only a few hundred devices (10% of the values in Table 33), and for New Install, each decile is only about 1,300 thermostats. When administrative costs are spread across a limited number of devices, the SWE ended up with a situation where the offering is not cost-effective for any combination of deciles.

5.2.4 MET-ED

The Met-Ed modeling for BYOT underscores the difference between the RAP and MAP perspectives. The RAP economic screening requires that each decile be cost-effective on its own to be included, while the MAP perspective allows deciles that are not cost-effective to be included, which allows fixed costs to be divided across more devices. For Met-Ed, no deciles are included in the RAP perspective, while five are included in the MAP model. Table 45 shows the MAP results. The average annual BYOT peak demand reduction capability under the MAP perspective is 2.6 MW, but the TRC ratio is just 1.01. Throughout this section acquisition costs are calculated prior to rounding the system level MW estimates. Dividing the spending values by rounded MW values may return slightly different values.

Table 45: Met-Ed BYOT Results - MAP

Metric	2021	2022	2023	2024	2025	Phase IV
System Level MW	1.6	2.0	2.5	3.1	3.8	2.6
Spend (Nominal $)	$120,230	$145,103	$178,739	$221,923	$274,750	$940,745
TRC Benefits (PV 2021$)	$84,704	$100,278	$120,899	$194,104	$233,031	$733,015
TRC Costs (PV 2021$)	$105,490	$120,659	$140,894	$165,925	$194,970	$727,939
TRC Net Benefits (PV 2021$)	($20,787)	($20,382)	($19,996)	$28,179	$38,061	$5,076
Acquisition Cost (Nominal $/kW)	$73.27	$72.49	$71.92	$71.67	$71.77	$72.08
Nominal Spend % of DSM Budget	0.48%	0.58%	0.72%	0.89%	1.10%	0.76%

Table 46 shows the RAP results for a New Install connected thermostat DR program in the Met-Ed service territory. Table 47 presents the MAP results. The SWE estimated an average annual Phase IV DR potential at 13.4 MW for the RAP scenario and 16.4 MW for the MAP scenario. The RAP scenario is slightly more attractive from a TRC standpoint, at 1.14, compared to 1.06 for the MAP scenario.

Table 46: Met-Ed New Thermostat Installation - RAP

Metric	2021	2022	2023	2024	2025	Phase IV
Meter Level MWh/year (EE)	3,781					3,781
System Level MW	14.9	14.1	13.4	12.7	12.1	13.4
Spend (Nominal $)	$4,855,241	$408,535	$396,911	$385,668	$374,795	$6,421,151
TRC Benefits (PV 2021$)	$3,679,205	$707,108	$652,286	$798,542	$736,632	$6,573,774
TRC Costs (PV 2021$)	$4,354,551	$388,859	$359,599	$332,584	$307,641	$5,743,234
TRC Net Benefits (PV 2021$)	($675,346)	$318,249	$292,687	$465,958	$428,991	$830,540
Acquisition Cost (Nominal $/kW)	$326.80	$28.94	$29.60	$30.28	$30.97	$95.53
Nominal Spend % of DSM Budget	19.52%	1.64%	1.60%	1.55%	1.51%	5.16%

Table 47: Met-Ed New Thermostat Installation - MAP

Metric	2021	2022	2023	2024	2025	Phase IV
Meter Level MWh/year (EE)	5,402					5,402
System Level MW	18.1	17.2	16.3	15.5	14.7	16.4
Spend (Nominal $)	$6,927,487	$574,879	$558,098	$541,858	$526,143	$9,128,467
TRC Benefits (PV 2021$)	$5,093,233	$860,072	$793,391	$971,285	$895,983	$8,613,963
TRC Costs (PV 2021$)	$6,212,215	$547,191	$505,634	$467,276	$431,871	$8,164,187
TRC Net Benefits (PV 2021$)	($1,118,982)	$312,881	$287,757	$504,009	$464,111	$449,776
Acquisition Cost (Nominal $/kW)	$383.35	$33.49	$34.22	$34.97	$35.75	$111.65
Nominal Spend % of DSM Budget	27.86%	2.31%	2.24%	2.18%	2.12%	7.34%

5.2.5 PENELEC

A BYOT offering is not cost-effective in the Penelec service territory under the RAP or MAP modeling perspective. There is no cost-effective potential for a New Install program under the RAP perspective, but the MAP model returns 4.5 MW of Phase IV DR potential. Table 48 shows the full MAP results. Allocating $2.07 million of Phase IV funding is estimated to return a net benefit of $19,629 and produce a TRC ratio of 1.01. Acquisition costs are calculated prior to rounding the system level MW estimates. Dividing the spending values by rounded MW values may return slightly different values.

Table 48: Penelec New Thermostat Installation - MAP

Metric	2021	2022	2023	2024	2025	Phase IV
Meter Level MWh/year (EE)	639					639
System Level MW	5.0	4.7	4.5	4.2	4.0	4.5
Spend (Nominal $)	$1,522,717	$141,026	$137,695	$134,488	$131,401	$2,067,327
TRC Benefits (PV 2021$)	$1,004,599	$189,707	$175,005	$260,209	$240,038	$1,869,558
TRC Costs (PV 2021$)	$1,367,111	$134,234	$124,751	$115,977	$107,857	$1,849,929
TRC Net Benefits (PV 2021$)	($362,512)	$55,473	$50,254	$144,233	$132,181	$19,629
Acquisition Cost (Nominal $/kW)	$307.53	$29.98	$30.81	$31.68	$32.58	$92.28
Nominal Spend % of DSM Budget	6.63%	0.61%	0.60%	0.59%	0.57%	1.80%

5.2.6 PENN POWER

The SWE's models show no cost-effective BYOT or New Install connected thermostat potential in the Penn Power service territory under the RAP or MAP modeling perspectives.

5.2.7 WEST PENN POWER

The SWE's models show no cost-effective BYOT or New Install connected thermostat potential in the West Penn Power service territory under the RAP or MAP modeling perspectives.

6 BEHAVIORAL DEMAND RESPONSE

BDR is a residential DR strategy that relies on timely customer notifications to elicit reductions in demand during DR event hours. BDR programs typically do not offer any financial incentives for customers to curtail usage and no load control equipment is installed in the home, other than the AMI meter. BDR programs are similar to Home Energy Report programs for EE. A treatment group is encouraged to conserve energy via messaging issued before and after DR events and is presented with social comparisons designed to promote demand reduction during event hours. BDR messaging can happen via email, text, phone, or social media.

Met-Ed, Penn Power, and West Penn Power implemented a BDR offering during Phase III and achieved approximately 11 MW of DR impacts from approximately 200,000 participating households in PY10. While the individual impacts are small, at 40-60 Watts per household for most BDR programs, a large number of households can be included in the program at a relatively low cost.

6.1 BDR MODELING ASSUMPTIONS

Modeling BDR potential requires many of the same type of assumptions as the connected thermostat offering. BDR programs can be offered on either an opt-in or opt-out basis. The SWE modeled the opt-out design, where candidate households are randomly assigned to either a treatment or control group, as it is the more common program delivery type and allows for impacts to be directly measured robustly. Key programmatic assumptions for BDR enrollment include the following:

- An EDC would target the BDR program at the top 50% of residential accounts with respect to summer weekday electric loads. Larger homes generally produce larger impacts, but the cost to message them is no different from a home with low on-peak electric demand.
- Not all accounts will have an email address or cell phone number on file with their EDC. The SWE assumed that 70% of targeted households will have adequate contact methods for issuing event notifications.
- Some treatment group homes will choose to opt-out of receiving BDR messaging or close their account with the EDC. The SWE Team assumed a 5% annual attrition with no refill.
- Because the average effect size for BDR is quite small, a large control group is needed for measurement purposes. The SWE assumed 25,000 households are withheld for evaluation regardless of EDC size.

Table 49 shows the modeled BDR treatment group size by EDC and year. If the modeled program is not cost-effective according to the TRC Test, the SWE assumed the population and potential to be zero.

Table 49: BDR Program Population, by EDC and Year

Year	PECO	PPL	Duquesne Light	FE: Met-Ed	FE: Penelec	FE: Penn Power	FE: West Penn
2021	461,704	389,846	152,316	141,005	140,672	22,905	182,922
2022	437,612	369,311	143,539	132,788	132,471	20,534	172,630
2023	414,712	349,792	135,196	124,977	124,677	18,280	162,847
2024	392,947	331,240	127,266	117,553	117,268	16,138	153,549
2025	372,258	313,606	119,729	110,497	110,225	14,101	144,710

The average BDR impact per treatment group household is assumed to be 0.05 kW at the meter. The 2021 program cost assumptions used for BDR are discussed below. An annual inflation rate of 2% is applied to costs for 2022-2025.

- **Fixed program administration**: an EDC may elect to use the same CSP for BDR and Home Energy Reports or select two different CSPs. Even if the same CSP is used, a significant amount of integration is required with the EDC customer information and meter data management systems to implement a BDR program. The SWE assumed $100,000 of fixed program administration costs annually regardless of the size of the treatment group.

- **Variable program administration**: communication costs are the primary volumetric costs associated with a BDR program. The SWE Team estimated the cost of email hosting, SMS, and voice notification fees to be $2 per household per summer.

- **Incentives**: BDR participants are offered no financial incentive to reduce peak demand. As a result, the EDC cost and the TRC cost are identical for BDR.

6.2 RESULTS

Table 50 presents the BDR modeling results for PECO. The average system-level DR potential over the five-year planning horizon is 22.3 MW. PECO's high avoided cost of transmission and distribution capacity cause the program to comfortably pass economic screening with a TRC ratio of 2.11 for the phase. The estimated budget requirement to achieve the modeled BDR potential is approximately $4.8 million, which is slightly over 1% of PECO's Phase IV EE&C funding. Throughout this section acquisition costs are calculated prior to rounding the system level MW estimates. Dividing the spending values by rounded MW values may return slightly different values.

Table 50: PECO BDR Potential and Economics

Metric	2021	2022	2023	2024	2025	Phase IV
System Level MW	24.8	23.5	22.3	21.1	20.0	22.3
Spend (Nominal $)	$1,023,407	$994,728	$966,974	$940,117	$914,132	$4,839,358
TRC Benefits (PV 2021$)	$1,952,240	$1,796,064	$1,652,682	$2,038,960	$1,875,561	$9,315,507
TRC Costs (PV 2021$)	$1,023,407	$946,819	$876,072	$810,718	$750,342	$4,407,358
TRC Net Benefits (PV 2021$)	$928,833	$849,246	$776,609	$1,228,242	$1,125,219	$4,908,149
Acquisition Cost (Nominal $/kW)	$41.27	$42.33	$43.42	$44.55	$45.72	$43.34
Nominal Spend % of DSM Budget	1.20%	1.16%	1.13%	1.10%	1.07%	1.13%

Table 51 shows the BDR modeling outputs for PPL. Like PECO, the assumed fixed program administrative cost is spread across a large number of households, which leads to a BDR program acquisition cost of approximately $43/kW-year. The PPL BDR program returns just under $2 in TRC benefits for each $1 of program expense.

Table 51: PPL BDR Potential and Economics

Metric	2021	2022	2023	2024	2025	Phase IV
System Level MW	21.3	20.2	19.1	18.1	17.2	19.2
Spend (Nominal $)	$879,691	$855,394	$831,888	$809,150	$787,158	$4,163,283
TRC Benefits (PV 2021$)	$1,557,338	$1,431,982	$1,316,948	$1,682,195	$1,546,436	$7,534,899
TRC Costs (PV 2021$)	$879,691	$814,196	$753,686	$697,778	$646,119	$3,791,470
TRC Net Benefits (PV 2021$)	$677,647	$617,786	$563,263	$984,417	$900,317	$3,743,429
Acquisition Cost (Nominal $/kW)	$41.23	$42.32	$43.46	$44.64	$45.87	$43.38
Nominal Spend % of DSM Budget	1.43%	1.39%	1.35%	1.32%	1.28%	1.35%

Table 52 shows the BDR results for Duquesne Light. The BDR offering becomes cost-effective in 2024 and 2025 once the generation capacity benefits from PJM PSA recognition are included in the benefits stack. However, for Phase IV as a whole, the BDR program fails economic screening with a TRC ratio of 0.78. Although the SWE showed the BDR demand reduction potential and budget requirements in Table 52, it contributes no potential and has no budget requirement in the overall estimates of Phase IV DR potential for Duquesne Light because the program is not cost-effective.

Table 52: Duquesne Light BDR Potential and Economics

Metric	2021	2022	2023	2024	2025	Phase IV
System Level MW	8.2	7.8	7.3	6.9	6.5	7.3
Spend (Nominal $)	$404,632	$394,819	$385,356	$376,233	$367,440	$1,928,479
TRC Benefits (PV 2021$)	$237,074	$216,760	$198,277	$373,423	$341,144	$1,366,678
TRC Costs (PV 2021$)	$404,632	$375,803	$349,130	$324,448	$301,604	$1,755,616
TRC Net Benefits (PV 2021$)	($167,558)	($159,043)	($150,853)	$48,975	$39,540	($388,939)
Acquisition Cost (Nominal $/kW)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nominal Spend % of DSM Budget	2.07%	2.02%	1.97%	1.92%	1.88%	1.97%

Table 53 presents the SWE's BDR modeling results for Met-Ed. The program is cost-effective, with a TRC ratio of 1.25 for Phase IV. A BDR program capable of delivering an average of 6.9 MW over the five-year phase would require approximately 1.5% of Met-Ed's Phase IV EE&C funding.

Table 53: Met-Ed BDR Potential and Economics

Metric	2021	2022	2023	2024	2025	Phase IV
System Level MW	7.7	7.3	6.8	6.4	6.0	6.9
Spend (Nominal $)	$382,010	$372,887	$364,092	$355,618	$347,454	$1,822,060
TRC Benefits (PV 2021$)	$442,572	$404,509	$369,683	$448,095	$408,992	$2,073,850
TRC Costs (PV 2021$)	$382,010	$354,927	$329,865	$306,670	$285,199	$1,658,671
TRC Net Benefits (PV 2021$)	$60,562	$49,582	$39,818	$141,425	$123,793	$415,179
Acquisition Cost (Nominal $/kW)	$49.51	$51.31	$53.23	$55.28	$57.46	$53.12
Nominal Spend % of DSM Budget	1.54%	1.50%	1.46%	1.43%	1.40%	1.47%

Table 54 shows the BDR results for Penelec. The BDR offering is not cost-effective for the first three summers of the phase. However, the offering becomes cost-effective once the generation capacity benefits from PJM PSA recognition are included in the benefits stack in 2024 and 2025. For Phase IV as a whole, the modeling shows BDR to be cost-effective with a TRC ratio of 1.10.

Table 54: Penelec BDR Potential and Economics

Metric	2021	2022	2023	2024	2025	Phase IV
System Level MW	7.7	7.3	6.8	6.4	6.0	6.8
Spend (Nominal $)	$381,344	$372,242	$363,467	$355,011	$346,866	$1,818,930
TRC Benefits (PV 2021$)	$355,595	$324,980	$297,005	$437,225	$399,064	$1,813,869
TRC Costs (PV 2021$)	$381,344	$354,313	$329,299	$306,147	$284,716	$1,655,820
TRC Net Benefits (PV 2021$)	($25,749)	($29,333)	($32,294)	$131,078	$114,347	$158,049
Acquisition Cost (Nominal $/kW)	$49.52	$51.33	$53.25	$55.30	$57.48	$53.13
Nominal Spend % of DSM Budget	1.66%	1.62%	1.58%	1.55%	1.51%	1.58%

Table 55 shows the BDR modeling outputs for Penn Power. As the smallest EDC, fixed program administration costs are a bigger barrier for Penn Power than for other EDCs. This is evident in the acquisition cost values for Penn Power that are significantly higher than other larger EDCs. Act 129 requires that each of the seven EDCs be treated independently, so we have not modeled any economies of scale across the four FirstEnergy companies. BDR economics are further challenged by the fact that Penn Power has no avoided cost of transmission capacity and among the lowest avoided cost of distribution capacity values in the Commonwealth. For Phase IV as a whole, the modeling shows BDR to produce at TRC ratio of 0.10 for Penn Power.

Table 55: Penn Power BDR Potential and Economics

Metric	2021	2022	2023	2024	2025	Phase IV
System Level MW	1.2	1.1	1.0	0.9	0.8	1.0
Spend (Nominal $)	$145,810	$143,889	$142,077	$140,372	$138,771	$710,919
TRC Benefits (PV 2021$)	$14,581	$12,670	$10,959	$14,156	$12,018	$64,384
TRC Costs (PV 2021$)	$145,810	$136,959	$128,721	$121,051	$113,906	$646,447
TRC Net Benefits (PV 2021$)	($131,230)	($124,289)	($117,762)	($106,894)	($101,888)	($582,063)
Acquisition Cost (Nominal $/kW)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nominal Spend % of DSM Budget	2.19%	2.16%	2.13%	2.11%	2.08%	2.13%

West Penn Power also has a very low avoided cost of transmission capacity for Phase IV and modest avoided cost of distribution capacity, as presented in Table 56. Although the SWE estimated close to 9 MW of DR potential from a BDR program, the Phase IV TRC ratio is just 0.53.

Table 56: West Penn Power BDR Potential and Economics

Metric	2021	2022	2023	2024	2025	Phase IV
System Level MW	10.0	9.4	8.9	8.4	7.9	8.9
Spend (Nominal $)	$465,844	$454,165	$442,892	$432,015	$421,522	$2,216,437
TRC Benefits (PV 2021$)	$144,219	$131,968	$120,937	$351,856	$322,031	$1,071,011
TRC Costs (PV 2021$)	$465,844	$432,291	$401,258	$372,552	$345,995	$2,017,939
TRC Net Benefits (PV 2021$)	($321,625)	($300,322)	($280,321)	($20,695)	($23,964)	($946,928)
Acquisition Cost (Nominal $/kW)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nominal Spend % of DSM Budget	1.98%	1.93%	1.88%	1.83%	1.79%	1.88%

7 LOAD CURTAILMENT

7.1 METHODOLOGY

Load curtailment potential for C&I customers is a function of several important factors. The SWE Team's EDC-specific top-down models utilize summer peak load forecasts as a foundation, and other relevant inputs include financial variables (retail rates, avoided capacity costs, avoided energy costs), how sensitive EDC customers are to changes in the price of electricity (DR price elasticity), and the components of program design (frequency of events, duration of events, notification time, incentive payments). Regarding program design, the SWE Team made a number of simplifying assumptions rather than producing an array of scenario-based estimates. Table 57 describes these assumptions, as well as the sources for other key inputs into the DR potential estimates. A discussion on DR price elasticities, and how they can be used to estimate load curtailment potential, follows the table. It is worth noting that the SWE Team produced estimates of both RAP and MAP. In the context of C&I load curtailment the SWE defined these terms as follows:

- **Realistic achievable potential**: load curtailment potential for a program where customer incentives are designed to maximize the present value of the net benefits of the program.
- **Maximum achievable potential**: load curtailment potential for a program where customer incentives are as high as they can be while still producing a cost-effective program (e.g., the largest incentive value such that the TRC ratio does not fall below 1).

Table 57: Summary of Input Assumptions and Sources

Input Variable	Sources, Notes, and Assumptions
Peak Load Forecast	The SWE Team used the PJM's summer peak load forecast, which is shown in Table 23. Because PJM is updating their forecasting process, and the changes are generally expected to have downward effect,[33] the SWE decreased the forecasts slightly (multiplied PJM's numbers by 99%). PJM's forecast is at the EDC level, not the sector level, so the SWE Team needed to disaggregate the peak load into peak load forecasts by sector (residential, SCI, LCI). Allocation shares are shown in Table 24. The SWE Team developed these using market data available to support the Commonwealth's Electric Generation Suppliers, customer level peak

---

[33] *See* http://insidelines.pjm.com/pjm-proposes-refinements-to-long-term-load-forecasting/.

Input Variable	Sources, Notes, and Assumptions
	demand data provided by the EDCs in response to the SWE's baseline study data request, and discussions with EDC technical staff.
Retail Electricity Cost ($/MWh)	The SWE Team calculated the retail rates for the SCI and LCI sectors using EIA data, by EDC.[34] Pennsylvania allows customers to choose their Electric Generation Supplier. To accommodate this feature, the SWE calculated the retail rates as a weighted average of the EDC-specific bundled rates and the average rate of the various competitive suppliers in Pennsylvania plus the EDC delivery-only rates.
Avoided Cost of Generation Capacity ($/kW-year)	The SWE Team developed avoided costs of generation capacity in preparation for the market potential studies using the results of PJM's BRA. For years that BRA results are not available, the SWE escalated known values using the calculation method described in the 2021 TRC Test Order. Per the 2021 TRC Test Order, these values are de-rated using EDC-specific factors for DR. The de-rated avoided costs are shown in Section 4.2.1.
Avoided Transmission and Distribution Capacity ($/kW-year)	The SWE Team calculated avoided T&D capacity costs using load growth related capital expenditure data provided by the EDCs. Per the 2021 TRC Test Order, the SWE Team multiplied these values by 60% for DR cost-effectiveness. These costs are shown in Section 4.2.2.
Avoided Energy Costs ($/MWh)	The SWE Team calculated avoided energy costs as the difference between Summer On-Peak rate and Summer Off-Peak rate, using the methodology prescribed by the 2021 TRC Test Order. These costs are shown in Section 4.2.3.
Program Design (# of events, event duration, notification level)	The SWE Team estimates of potential assume a three-hour event duration. The SWE also assumed that there will be an average of seven summer events called (21 total event hours for the summer). For more information on the program design research that the SWE Team conducted, see Section 2 of this report. The SWE Team derived load curtailment potential estimates under both a *day-ahead* notification design and a *day-of* notification design. *Day-ahead* notification assumes participants are notified of the pending event a day in advance, and *day-of* notification assumes a three- to six-hour notice.

---

[34] *See* the Annual Electric Power Industry Report, Form EIA-861 at https://www.eia.gov/electricity/data/eia861/. At the time of this research, the most recent year available was 2017. Costs were escalated annually, so the rates are in 2021 dollars.

Input Variable	Sources, Notes, and Assumptions
	Potential is higher under the *day-ahead* notification design as this provides participants with greater opportunities to shift energy-intensive tasks to off-peak periods.
Participant Incentive	For C&I DR, the SWE Team modeled the incentive as a reservation payment. This is an annual payment provided to the participant. In exchange, the participant agrees to curtail load when events are dispatched. For RAP, the SWE's approach to setting incentive levels involved maximizing net benefits. To determine the optimal incentive level, the SWE Team performed a simulation where the critical input was the incentive level and the critical output was the net benefit of the DR program. The simulation leveraged several of the inputs discussed herein and was repeated for each of the five years in the study horizon to establish different incentive levels by year. Table 59 shows the incentive levels used in calculating RAP (by EDC and program year). For MAP, the goal of the simulation was to determine the greatest possible incentive level such that the program remains cost-effective. As with the RAP, the SWE Team repeated the simulation for each of the five years in the study horizon. Table 60 shows the incentive levels used in calculating RAP (by EDC and program year). Per the 2021 TRC Test Order, 75% of the participant is treated as a TRC Cost.
Price Elasticity of Demand Coefficients	The price elasticity of demand coefficients used in this research were derived primarily from two years of DR performance data for C&I DR participants in Pennsylvania and supplemented with program performance data from other jurisdictions. More information is included in Section 7.1.1.
Discount Rate	3% real, 5% nominal, per the 2021 TRC Test Order.
Program Management Budget (Non-Incentive Costs)	Assumed to equal 25% of the total incentive cost (where the total incentive cost is the reservation payment multiplied by DR potential).
Line Losses	Not applicable. The load curtailment opportunity is modeled "top-down" using system loads so the resulting estimates of DR potential are inclusive of line losses.

7.1.1 PRICE ELASTICITY

Price elasticity of demand is the ratio between percentage change in the quantity of electricity demanded and the percentage change in the price (including an incentive) of DR. The traditional elasticity formula is shown in Equation (1).

$$Elasticity = \frac{\%\ change\ in\ Quantity}{\%\ change\ in\ Price} \tag{1}$$

The numerator of Equation (1) is expanded in Equation (2), and the denominator is expanded in Equation (3).

$$\%\ change\ in\ Quantity = \frac{(Summer\ peak -\ DR\ potential) - Summer\ Peak}{Summer\ Peak} * 100\% \tag{2}$$

$$\%\ change\ in\ Price = \frac{(Retail\ Rate + Incentive\ Payment) - Retail\ Rate}{Retail\ Rate} * 100\% \tag{3}$$

The SWE Team derived the price elasticity of demand coefficients used in this potential study from two years of DR performance data for C&I DR participants in Pennsylvania. The SWE calculated the numerator of the elasticity calculation (% change in Quantity) based on participant reference loads and impacts, which was aggregated across the SCI and LCI sectors. The SWE Team calculated the denominator of the elasticity calculation (% change in Price) based on (1) the average reservation payment in place ($25/kW-year), (2) the number of event hours per participant, and (3) the average SCI and LCI retail rates expressed as an "all in" cost per kWh.

After calculating initial elasticity values, the next step the SWE Team took was to *dilute* them. This was necessary because not all C&I customers participated in the DR programs. This needs to be accounted for in the model since it is a top-down model. To this end, the SWE assumed that the participants from the LCI sector represented 25% of the total peak for that sector and the participants from the SCI sector represented 5% of the total peak for the SCI sector. The SWE Team then multiplied the initial elasticity values by these dilution factors.

Phase III DR programs in Pennsylvania leveraged a day-ahead forecasting system. This means that the calculations described above produced day-ahead elasticity values, but not day-of elasticity values. To produce day-of elasticities, the SWE Team leveraged elasticity research done in California.[35] Using the California elasticity data, the SWE estimated the ratio between day-ahead elasticities and day-of elasticities. Multiplying this ratio by the Pennsylvania-specific day-ahead elasticity values yielded day-of elasticity values. The final elasticity values are shown in Table 58.

---

[35] *See* the *Act 129 Statewide Evaluator Demand Response Potential for Pennsylvania* – Final Report at http://www.puc.pa.gov/pcdocs/1345077.docx.

Table 58: Price Elasticity Values

Sector	Day-Ahead Elasticity	Day-Of Elasticity
SCI	0.0009	0.0006
LCI	0.0041	0.0022

7.1.2 SAMPLE CALCULATION

Rearranging the terms in the Equation (1) yields the following:

$$\%\ change\ in\ Quantity = (Elasticity)\ \times\ (\%\ change\ in\ Price) \tag{4}$$

Note that Equations (2) and (4) both have "% change in Quantity" on the left-hand side. Combining these two equations yields:

$$(Elasticity)\ \times\ (\%\ change\ in\ Price) = \frac{(Summer\ peak -\ DR\ potential) - Summer\ Peak}{Summer\ Peak} * 100\% \tag{5}$$

The terms in Equation (5) can then be rearranged to solve for DR potential:

$$DR\ Potential = \frac{(Elasticity * (\%\ change\ in\ Price) * Summer\ Peak)}{100\%} \tag{6}$$

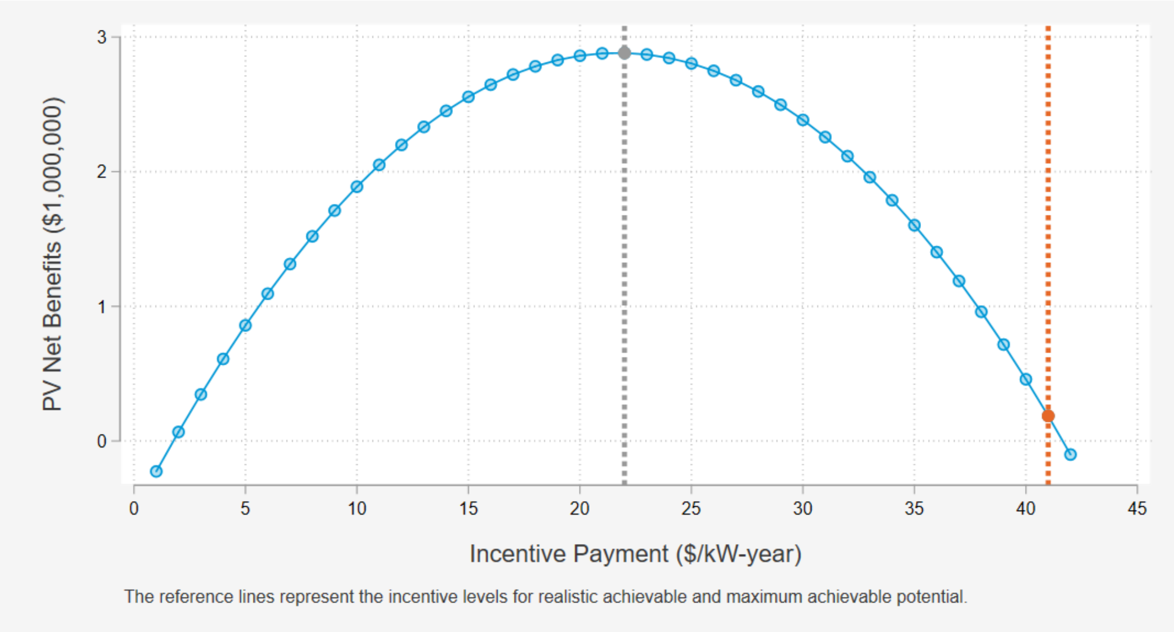
Using the LCI day-ahead elasticity from Table 58 (0.0041), a summer peak of 2,000 MW, a retail rate of $0.07 ($/kWh), and an incentive reservation payment of $25 ($/kW-year) spread across 20 event hours, DR potential would be calculated as:

$$DR\ Potential = -\frac{0.0041 * \left(\frac{(0.07 + 25/20) - 0.07}{0.07} * 100\%\right) * 2{,}000}{100\%} = 146\ MW$$

7.2 COST AND BENEFIT STREAMS

The primary cost of a C&I load curtailment program are the customer incentive costs incurred by the EDCs. As incentive costs increase, so does the DR potential of the program, but it is important to consider the net benefits produced by the program rather than just DR potential. As noted, the SWE Team approached incentives from two different perspectives. The SWE Team calculated estimates of RAP using an incentive level that maximizes the net benefits of the program. Estimates of MAP were calculated using an incentive level that keeps the net benefits from dropping below $0. Figure 9 summarizes the simulation exercise. In this example, net benefits max out around $3 million, at which point the incentive payment is $21/kW-year. This incentive level would then be used to estimate RAP. The greatest incentive level that maintains positive net benefits is $41/kW-year – this is the value that would be used to estimate MAP.

Figure 9: Relationship Between Net Benefits and Incentive Level



The reference lines represent the incentive levels for realistic achievable and maximum achievable potential.

Simulation results are shown in Table 59 and Table 60. The jump in incentive levels between PY15 and PY16 is due to the fact that avoided costs are aligned with PJM's forward planning cycle and Act 129 programs will miss the opportunity to commit as a PSA for the first three years. The relatively low incentive levels for Penn Power and West Penn Power are due to low avoided cost of transmission capacity forecasts for these EDCs. Penn Power's avoided cost of transmission capacity forecast included all zeros, and West Penn Power's forecast was only slightly higher than Penn Power. PPL's avoided cost of transmission capacity forecast also included all zeros, but PPL had the highest forecast for avoided cost of distribution capacity.

Table 59: Incentive Payments, by EDC and Program Year ($/kW-year) – Realistic Potential

Year	Sector	EDC						
		DLC	PECO	PPL	ME	PN	PP	WPP
PY13 (2021-2022)	SCI	14	39	36	29	23	6	7
	LCI	10	8	0	8	9	0	1
PY14 (2022-2023)	SCI	15	40	37	29	24	6	7
	LCI	10	8	0	8	9	0	1
PY15 (2023-2024)	SCI	15	41	38	30	24	6	7
	LCI	10	8	0	8	10	0	1
PY16 (2024-2025)	SCI	31	56	54	40	39	9	24
	LCI	26	22	15	18	25	3	17
PY17 (2025-2026)	SCI	32	57	55	41	40	10	25
	LCI	27	23	16	18	25	3	17

Table 60: Incentive Payments, by EDC and Program Year ($/kW-year) – Maximum Potential

Year	Sector	EDC						
		DLC	PECO	PPL	ME	PN	PP	WPP
PY13 (2021-2022)	SCI	28	78	72	57	46	11	14
	LCI	19	15	0	15	18	0	1
PY14 (2022-2023)	SCI	29	80	74	58	47	11	14
	LCI	19	15	0	15	18	0	1
PY15 (2023-2024)	SCI	29	81	75	59	47	12	14
	LCI	19	15	0	15	19	0	1
PY16 (2024-2025)	SCI	62	112	107	80	78	18	48
	LCI	52	44	30	36	49	6	33
PY17 (2025-2026)	SCI	64	114	109	82	80	19	49
	LCI	53	45	31	36	50	6	34

There are two benefit streams in the cost-effectiveness calculations: avoided energy benefits and avoided capacity benefits. Regarding avoided energy benefits, the SWE assumed that the DR programs will be energy neutral. That is, the energy avoided during the DR event hours will be used during off-peak hours. Thus, the avoided energy benefit is simply the product of DR potential and the differential between on-peak and off-peak energy prices. By EDC and year, forecasted avoided energy costs (calculated as the difference between summer on-peak and summer off-peak energy prices) are shown in Section 4.2.3 (Table 30).

The avoided capacity benefits are calculated in a similar manner. For SCI, avoided capacity benefits are the product of DR potential and the sum of avoided GT&D capacity costs. By EDC and year, avoided GT&D capacity costs are shown in Sections 4.2.1 and 4.2.2 (Table 27, Table 28, and Table 29). For LCI, the SWE did not include avoided distribution costs in the calculation. The logic behind this difference is that LCI customers receive service at primary voltage and thus bypass much of the secondary distribution system. As such, the 2021 TRC Test Order directed EDCs not to apply avoided distribution costs to these customers.

7.3 POTENTIAL BY EDC

7.3.1 DEMAND RESPONSE POTENTIAL

Figure 10 shows estimates of RAP under the day-ahead and day-of notification program design, by EDC and program year. As discussed, the jump between PY15 and PY16 is due to the alignment with PJM's forward planning cycle. DR potential is greatest for PECO, followed by PPL. Duquesne, Met-Ed, and Penelec all have similar trajectories. This is because these EDCs have similar peak load forecasts and similar avoided G&T capacity costs. Penn Power shows the least amount of potential as Penn Power has the smallest peak load forecast, no avoided transmission capacity costs, and relatively low avoided distribution capacity costs. Penn Power also has the avoided cost of generation capacity de-rated significantly based on PJM's simulation results in PY16 and PY17.

Figure 10: Realistic Achievable Potential, by EDC, Program Year, and Notification Level

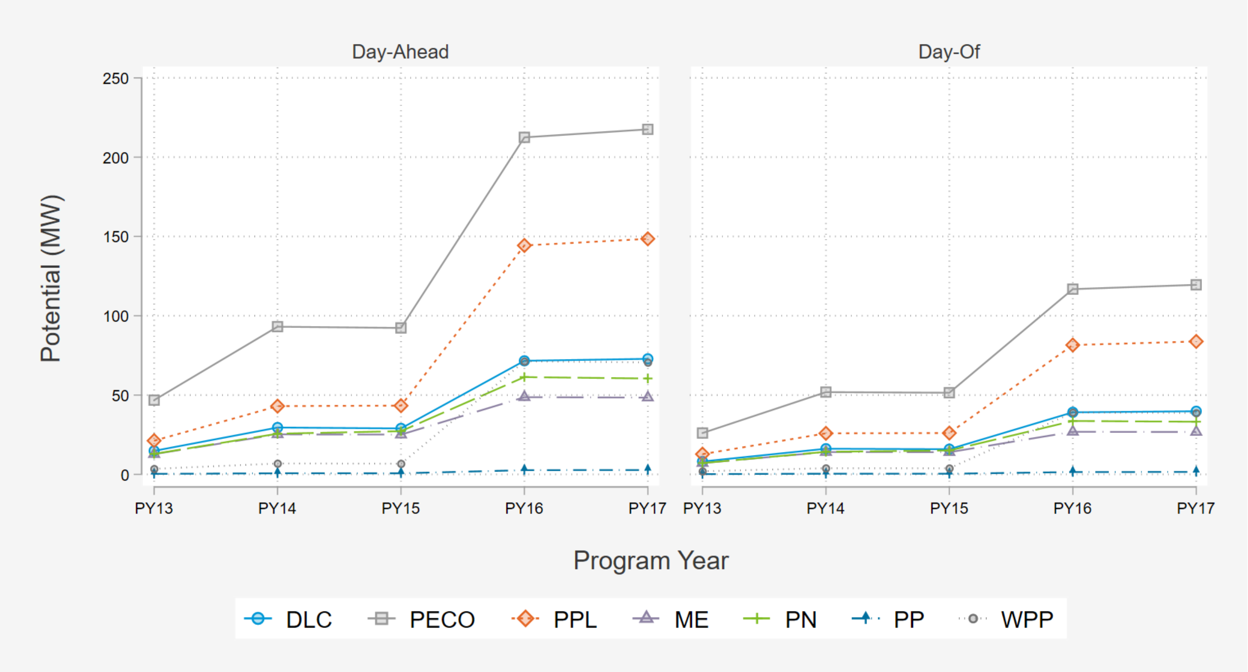


Table 61 through Table 67 show DR potential for the four different combinations of potential type (realistic and maximum) and notification level (day-of and day-ahead), by EDC and program year. Results are presented for the small and large sectors separately, and a total C&I sum is also shown.

Table 61: Duquesne C&I DR Potential (MW)

Year	Sector	Realistic Achievable Potential		Maximum Achievable Potential	
		Day-Of	Day-Ahead	Day-Of	Day-Ahead
PY13 (2021-2022)	SCI	1.3	2.2	2.7	4.4
	LCI	6.8	12.7	12.9	24.0
	Total	8.1	14.9	15.6	28.5
PY14 (2022-2023)	SCI	2.8	4.7	5.4	9.0
	LCI	13.4	24.9	25.5	47.3
	Total	16.2	29.6	30.9	56.3
PY15 (2023-2024)	SCI	2.7	4.6	5.3	8.8
	LCI	13.2	24.4	25.0	46.4
	Total	15.9	29.0	30.3	55.3
PY16 (2024-2025)	SCI	5.6	9.3	11.1	18.5
	LCI	33.6	62.4	67.2	124.7
	Total	39.2	71.6	78.3	143.3
PY17 (2025-2026)	SCI	5.6	9.4	11.3	18.7
	LCI	34.2	63.5	67.1	124.7
	Total	39.8	72.9	78.4	143.4

Table 62: PECO C&I DR Potential (MW)

Year	Sector	Realistic Achievable Potential		Maximum Achievable Potential	
		Day-Of	Day-Ahead	Day-Of	Day-Ahead
PY13 (2021-2022)	SCI	8.2	13.6	16.4	27.3
	LCI	17.9	33.2	33.5	62.2
	Total	26.1	46.8	49.9	89.5
PY14 (2022-2023)	SCI	16.6	27.6	33.3	55.2
	LCI	35.3	65.5	66.1	122.8
	Total	51.9	93.1	99.4	178.1
PY15 (2023-2024)	SCI	16.8	27.9	33.1	55.1
	LCI	34.7	64.5	65.1	120.9
	Total	51.5	92.3	98.2	175.9
PY16 (2024-2025)	SCI	22.6	37.6	45.2	75.1
	LCI	94.2	175.0	188.4	349.9
	Total	116.8	212.5	233.6	425.0
PY17 (2025-2026)	SCI	22.6	37.6	45.3	75.2
	LCI	96.9	179.9	189.6	352.1
	Total	119.5	217.6	234.9	427.3

Table 63: PPL C&I DR Potential (MW)

Year	Sector	Realistic Achievable Potential		Maximum Achievable Potential	
		Day-Of	Day-Ahead	Day-Of	Day-Ahead
PY13 (2021-2022)	SCI	12.8	21.3	25.6	42.5
	LCI	0.0	0.0	0.0	0.0
	Total	12.8	21.3	25.6	42.5
PY14 (2022-2023)	SCI	25.9	43.1	51.8	86.1
	LCI	0.0	0.0	0.0	0.0
	Total	25.9	43.1	51.8	86.1
PY15 (2023-2024)	SCI	26.1	43.3	51.5	85.5
	LCI	0.0	0.0	0.0	0.0
	Total	26.1	43.3	51.5	85.5
PY16 (2024-2025)	SCI	36.5	60.7	72.4	120.2
	LCI	45.1	83.7	90.1	167.4
	Total	81.6	144.4	162.5	287.6
PY17 (2025-2026)	SCI	36.6	60.8	72.5	120.4
	LCI	47.3	87.8	91.6	170.1
	Total	83.8	148.5	164.1	290.5

Table 64: Met-Ed C&I DR Potential (MW)

Year	Sector	Realistic Achievable Potential		Maximum Achievable Potential	
		Day-Of	Day-Ahead	Day-Of	Day-Ahead
PY13 (2021-2022)	SCI	2.4	4.0	4.7	7.9
	LCI	4.8	8.8	8.9	16.5
	Total	7.2	12.8	13.6	24.4
PY14 (2022-2023)	SCI	4.7	7.9	9.5	15.8
	LCI	9.4	17.4	17.6	32.6
	Total	14.1	25.3	27.1	48.4
PY15 (2023-2024)	SCI	4.8	8.0	9.5	15.8
	LCI	9.2	17.1	17.2	32.0
	Total	14.0	25.1	26.7	47.8
PY16 (2024-2025)	SCI	6.4	10.6	12.8	21.2
	LCI	20.5	38.1	41.0	76.2
	Total	26.9	48.7	53.8	97.4
PY17 (2025-2026)	SCI	6.5	10.7	12.9	21.5
	LCI	20.3	37.7	40.6	75.4
	Total	26.8	48.4	53.5	96.9

Table 65: Penelec C&I DR Potential (MW)

Year	Sector	Realistic Achievable Potential		Maximum Achievable Potential	
		Day-Of	Day-Ahead	Day-Of	Day-Ahead
PY13 (2021-2022)	SCI	2.0	3.2	3.9	6.5
	LCI	5.2	9.7	10.4	19.4
	Total	7.2	12.9	14.3	25.9
PY14 (2022-2023)	SCI	4.0	6.6	7.8	13.0
	LCI	10.3	19.0	20.5	38.1
	Total	14.3	25.7	28.3	51.1
PY15 (2023-2024)	SCI	3.9	6.5	7.7	12.8
	LCI	11.2	20.8	21.2	39.4
	Total	15.1	27.3	28.9	52.2
PY16 (2024-2025)	SCI	6.3	10.4	12.5	20.8
	LCI	27.4	51.0	53.8	99.9
	Total	33.7	61.4	66.3	120.7
PY17 (2025-2026)	SCI	6.3	10.5	12.6	20.9
	LCI	26.9	50.0	53.8	100.0
	Total	33.2	60.5	66.4	120.9

Table 66: Penn Power C&I DR Potential (MW)

Year	Sector	Realistic Achievable Potential		Maximum Achievable Potential	
		Day-Of	Day-Ahead	Day-Of	Day-Ahead
PY13 (2021-2022)	SCI	0.2	0.4	0.4	0.7
	LCI	0.0	0.0	0.0	0.0
	Total	0.2	0.4	0.4	0.7
PY14 (2022-2023)	SCI	0.4	0.7	0.8	1.3
	LCI	0.0	0.0	0.0	0.0
	Total	0.4	0.7	0.8	1.3
PY15 (2023-2024)	SCI	0.4	0.7	0.9	1.4
	LCI	0.0	0.0	0.0	0.0
	Total	0.4	0.7	0.9	1.4
PY16 (2024-2025)	SCI	0.6	1.1	1.3	2.1
	LCI	0.9	1.6	1.8	3.3
	Total	1.5	2.7	3.0	5.4
PY17 (2025-2026)	SCI	0.7	1.2	1.3	2.2
	LCI	0.9	1.6	1.7	3.2
	Total	1.6	2.8	3.1	5.4

Table 67: West Penn Power C&I DR Potential (MW)

Year	Sector	Realistic Achievable Potential		Maximum Achievable Potential	
		Day-Of	Day-Ahead	Day-Of	Day-Ahead
PY13 (2021-2022)	SCI	1.0	1.6	1.9	3.2
	LCI	1.0	1.9	1.0	1.9
	Total	2.0	3.5	2.9	5.1
PY14 (2022-2023)	SCI	1.9	3.2	3.9	6.4
	LCI	2.0	3.7	2.0	3.7
	Total	3.9	6.9	5.8	10.1
PY15 (2023-2024)	SCI	1.9	3.1	3.8	6.3
	LCI	1.9	3.6	1.9	3.6
	Total	3.8	6.8	5.7	9.9
PY16 (2024-2025)	SCI	6.4	10.7	12.8	21.3
	LCI	32.6	60.6	63.3	117.6
	Total	39.0	71.2	76.2	138.9
PY17 (2025-2026)	SCI	6.6	10.9	12.9	21.4
	LCI	32.1	59.7	64.2	119.3
	Total	38.7	70.6	77.1	140.7

7.3.2 COST-EFFECTIVENESS

As discussed in Section 4.1, the Commission adopted a 75% participant cost assumption in the 2016 TRC Test Order[36] and repeated the instruction in the 2021 TRC Test Order. This assumption was set forth in California's 2010 DR Cost-Effectiveness Protocols. This policy directive still considers incentives as a proxy for participant cost but takes the perspective that customers are generally rational and would likely only participate in a DR program if they felt the benefits of participation outweighed the costs. The result of the 75% participant cost assumption is that 75% of incentives are used in the calculation of TRC costs and TRC ratios. (From the Utility Cost Test perspective, 100% of incentive costs would fold into TRC costs rather than 75%.) The other component of TRC costs is the program administrator budget.

TRC ratios for the day-ahead and day-of program design are shown in Table 68. The TRC ratios are similar across EDCs because the SWE used the same modeling approach (e.g., maximize net benefits) for all EDCs. Note that these ratios are for the RAP estimates, not MAP estimates. For maximum achievable estimates, the SWE Team calculated the incentives such that the TRC ratio is slightly above 1.0.

---

[36] *See* the *Final 2016 TRC Test Order*, Docket No. M-2015-2468992 (entered June 22, 2015), at http://www.puc.pa.gov/pcdocs/1367195.docx.

Table 68: Phase IV TRC Ratios, by EDC – Realistic Achievable

EDC	Day-Ahead	Day-Of
Duquesne Light	2.00	2.00
PECO	2.00	2.00
PPL	2.00	2.00
FE: Met-Ed	2.01	2.01
FE: Penelec	2.01	2.01
FE: Penn Power	2.03	2.04
FE: West Penn Power	2.00	2.00

Table 69 shows total Phase IV expenditures, present value costs, and present value benefits associated with capturing the DR potential, by EDC and notification level. The values in the table represent financials under the RAP design rather than MAP. The differences in financials across EDCs are largely tied to DR potential. Note that "Scenario Spend" represents total Phase IV spending without discounting. "Present Value Cost" differs from "Scenario Spend" for two reasons: (1) the present value costs are discounted so that they are in 2021 dollars, and (2) only 75% of incentive costs are included in the TRC cost calculation (see the discussion at the beginning of this section or in Section 4.1). The PVNB are simply the difference between present value benefits and present value costs.

Table 69: DR Financials – Realistic Achievable Potential

EDC	Notification	Scenario Spend ($)	Present Value Benefit (2021$)	Present Value Cost (2021$)	Project Total PVNB (2021$)
DLC	Day-Of	$2,585,463	$4,441,545	$2,222,889	$2,218,655
	Day-Ahead	$4,712,366	$8,093,233	$4,051,042	$4,042,191
PECO	Day-Of	$9,233,851	$16,037,026	$8,020,469	$8,016,557
	Day-Ahead	$16,319,577	$28,317,069	$14,163,521	$14,153,548
PPL	Day-Of	$7,827,207	$13,651,405	$6,838,044	$6,813,361
	Day-Ahead	$13,282,940	$23,145,386	$11,595,465	$11,549,921
ME	Day-Of	$1,793,741	$3,145,945	$1,566,515	$1,579,430
	Day-Ahead	$3,160,198	$5,539,395	$2,758,151	$2,781,244
PN	Day-Of	$2,341,063	$4,055,982	$2,022,314	$2,033,668
	Day-Ahead	$4,204,460	$7,280,956	$3,630,371	$3,650,585
PP	Day-Of	$24,548	$43,408	$21,340	$22,068
	Day-Ahead	$41,810	$74,032	$36,320	$37,712
WPP	Day-Of	$1,457,543	$2,461,409	$1,232,944	$1,228,466
	Day-Ahead	$2,637,884	$4,452,886	$2,230,961	$2,221,925

7.4 POTENTIAL BY CUSTOMER CLASS

As shown in Figure 11, the majority of the C&I DR potential falls in the LCI sector. In the last two years of Phase IV, LCI DR potential exceeds SCI DR potential by a ratio of approximately 3:1.

Figure 11: Realistic Achievable Potential, by Market Segment, Program Year, and Notification Level

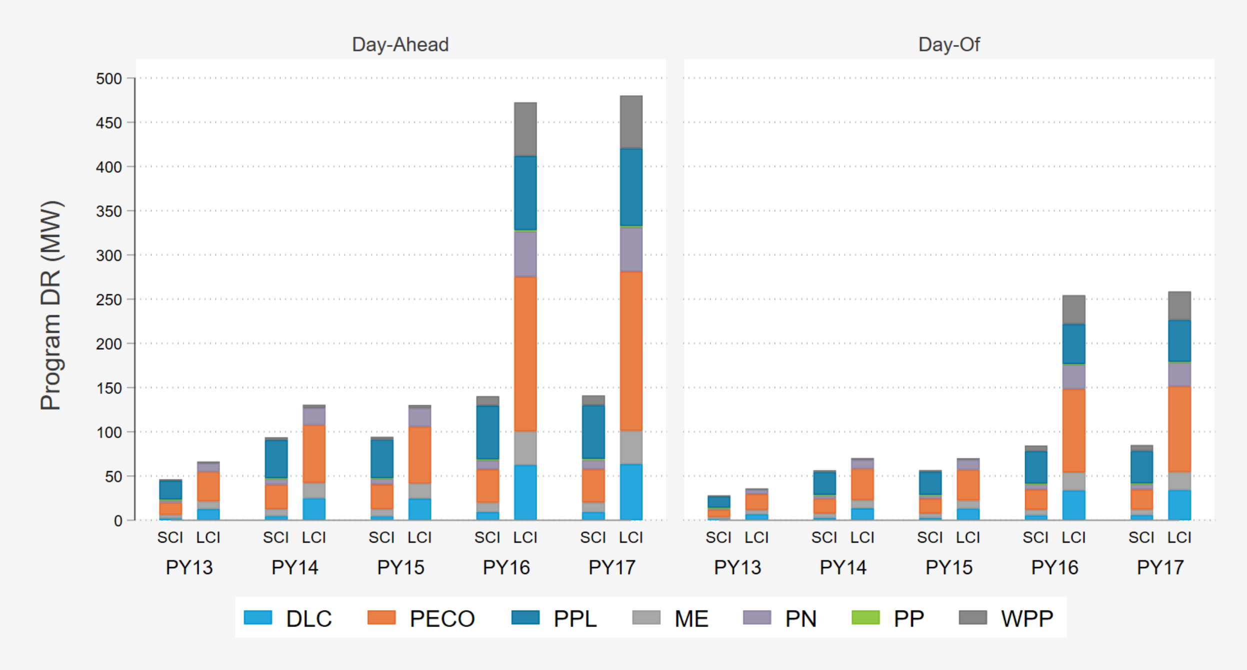


Table 70 shows the same financial outputs that are shown in Table 69 but only for the SCI sector. Similarly, Table 71 shows the financial outputs for the LCI sector. The values in Table 70 and Table 71 sum to the values in Table 69.

Table 70: DR Financials for SCI – Realistic Achievable Potential

EDC	Notification	Scenario Spend ($)	Present Value Benefits (2021$)	Present Value Costs (2021$)	Total PVNB (2021$)
DLC	Day-Of	$455,178	$792,657	$393,806	$398,851
	Day-Ahead	$756,123	$1,316,728	$654,174	$662,554
PECO	Day-Of	$4,229,915	$7,480,026	$3,733,101	$3,746,925
	Day-Ahead	$7,026,552	$12,425,498	$6,201,267	$6,224,230
PPL	Day-Of	$6,394,856	$11,262,160	$5,631,836	$5,630,323
	Day-Ahead	$10,622,860	$18,708,216	$9,355,365	$9,352,851
ME	Day-Of	$872,699	$1,546,409	$770,924	$775,484
	Day-Ahead	$1,449,690	$2,568,828	$1,280,626	$1,288,201
PN	Day-Of	$730,815	$1,283,677	$639,612	$644,066
	Day-Ahead	$1,213,998	$2,132,390	$1,062,495	$1,069,894
PP	Day-Of	$19,285	$33,589	$16,901	$16,688
	Day-Ahead	$32,035	$55,796	$28,075	$27,721
WPP	Day-Of	$351,970	$603,628	$299,976	$303,652
	Day-Ahead	$584,677	$1,002,720	$498,307	$504,414

Table 71: DR Financials for LCI – Realistic Achievable Potential

EDC	Notification	Scenario Spend ($)	Present Value Benefits (2021$)	Present Value Costs (2021$)	Total PVNB (2021$)
DLC	Day-Of	$2,130,285	$3,648,887	$1,829,083	$1,819,805
	Day-Ahead	$3,956,243	$6,776,505	$3,396,868	$3,379,637
PECO	Day-Of	$5,003,936	$8,557,000	$4,287,368	$4,269,632
	Day-Ahead	$9,293,024	$15,891,571	$7,962,254	$7,929,317
PPL	Day-Of	$1,432,351	$2,389,246	$1,206,208	$1,183,038
	Day-Ahead	$2,660,080	$4,437,171	$2,240,101	$2,197,070
ME	Day-Of	$921,042	$1,599,536	$795,590	$803,946
	Day-Ahead	$1,710,507	$2,970,567	$1,477,525	$1,493,043
PN	Day-Of	$1,610,248	$2,772,305	$1,382,703	$1,389,603
	Day-Ahead	$2,990,461	$5,148,567	$2,567,876	$2,580,690
PP	Day-Of	$5,263	$9,819	$4,440	$5,380
	Day-Ahead	$9,775	$18,236	$8,245	$9,991
WPP	Day-Of	$1,105,573	$1,857,782	$932,968	$924,814
	Day-Ahead	$2,053,208	$3,450,166	$1,732,655	$1,717,511

TRC ratios by market segment and notification level are shown in Table 72. The TRC ratios are similar across EDCs because the same modeling approach (e.g., maximize net benefits) was used for all EDCs.

Note that these ratios are for the RAP estimates, not MAP estimates. For maximum achievable estimates, incentives were calculated such that the TRC ratio does not drop below 1.

Table 72: TRC Ratios, by EDC and Sector

EDC	SCI		LCI	
	Day-Ahead	Day-Of	Day-Ahead	Day-Of
DLC	2.01	2.01	1.99	1.99
PECO	2.00	2.00	2.00	2.00
PPL	2.00	2.00	1.98	1.98
ME	2.01	2.01	2.01	2.01
PN	2.01	2.01	2.00	2.00
PP	1.99	1.99	2.21	2.21
WPP	2.01	2.01	1.99	1.99

7.5 PJM COMMITMENTS

Act 129 DR programs operate at the retail level against a backdrop of robust and mature wholesale DR markets organized by PJM. In Phase III of Act 129, many of the large participating customers in EDC programs also held PJM commitments because dual participation was allowed. In a Phase IV program design, where EDCs nominate their DR programs as PSAs to PJM, any participant with a capacity commitment in PJM would not be able to also participate in an EDC Act 129 program. Table 73 summarizes the number of participating locations and magnitude of DR commitments by EDC service territory for the 2019/2020 delivery year.

Table 73: PJM Demand Response – Delivery Year 2019/2020 Active Participants

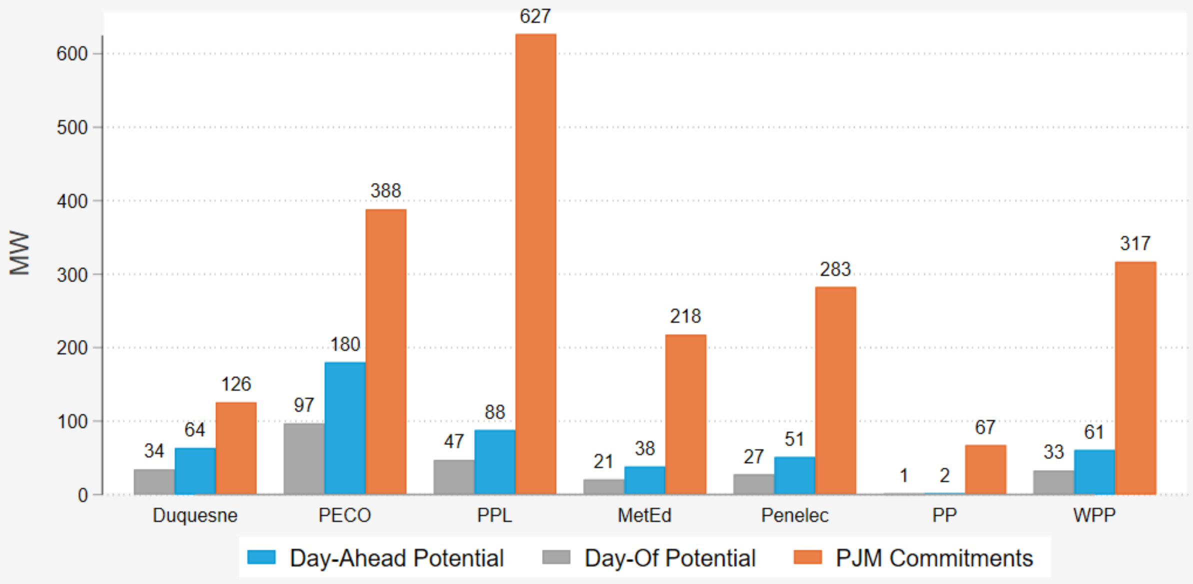
Zone	EDC	Economic		Load Management		Unique	
		Locations	MW	Locations	MW	Locations	MW
DUQ	DLC	5	16.0	357	109.8	359	125.6
PECO	PECO	38	126.5	994	320.4	1,003	388.2
PPL	PPL	26	211.5	1,107	518.6	1,117	626.8
METED	ME	27	36.7	429	210.9	433	217.6
PN	PN	2	62.0	490	260.5	491	282.5
ATSI	PP	2	45.2	92	67.2	92	67.2
APS	WPP	11	48.2	565	315.9	566	316.9

Source: https://www.pjm.com/-/media/markets-ops/dsr/2019-demand-response-activity-report.ashx?la=en

The average commitment per location in Table 73 is approximately 500 kW. This average consists of varying commitment levels, but the implication is that Pennsylvania businesses with PJM commitments are generally large customers – likely members of the LCI class in this study.

Figure 12 compares committed PJM reductions (in delivery year 2019/2020) with LCI DR potential estimates, by EDC. Note that the potential estimates shown in the table represent the greatest single-year estimate of potential across the phase, not averages across the phase. For each EDC service territory, the existing PJM commitments exceed our estimates of Act 129 DR potential. The differences between the potential estimates and the actual PJM commitments can largely be traced back to program design. The SWE's estimates assume 21 hours of DR per summer – seven different three-hour events. Historically, PJM DR events have been much less frequent.

Figure 12: PJM Commitments and LCI DR Potential



Potential estimates shown here represent the greatest single-year estimate of LCI DR potential across the phase.

The SWE Team's conclusion based on this comparison is that the DR market for the LCI sector is already saturated. If Phase IV DR programs were nominated as PSAs, Pennsylvania businesses would need to choose which program to participate in. Given the historically infrequent dispatch of emergency load management at PJM and compensation equal to the full capacity clearing price, the SWE believes most businesses would opt to participate in PJM. Based on this comparison, our estimates of Phase IV Act 129 DR program potential are limited to the SCI sector and exclude any estimated load curtailment potential from the LCI sector.

8 BEHIND THE METER BATTERY STORAGE

Battery storage is a technology capable of shaving peaks and filling valleys to flatten energy demand, much like other DR applications. This technology is the topic of policy analysis and even procurement mandates in some states. While most DR applications consist of avoiding energy use during peak hours or shifting demand to off-peak hours, battery storage can be used to flatten loads by charging during periods of low demand (essentially storing lower cost energy) and discharging during periods of high prices and demand.

In this section, the SWE focuses on cost and benefit considerations for lithium-ion battery systems. While there are many energy storage technologies, lithium-ion battery systems are the most common form of energy storage currently being deployed in the market.

8.1 BATTERY TECHNOLOGY AND COSTS

Lithium-ion battery system costs have declined in recent years and are expected to continue to decrease in the future. These costs can be divided into different components, which, at a high level, include the costs of battery equipment, inverters, and other equipment (commonly referred to as balance of system), as well as installation. These costs are all incurred upfront when the battery system is purchased and installed. Additionally, systems typically incur annual fixed operation and maintenance (FOM) costs for each year the system is in operation.

Cost components are often denoted either in terms of battery capacity ($/kW) or battery duration ($/kWh). Costs that are denoted in terms of battery capacity ($/kW), such as the inverter, are the same for a given battery capacity regardless of its duration. By contrast, costs that are denoted in terms of battery duration ($/kWh), such as the battery pack, increase directly with battery duration. In the case of battery packs, this is because additional raw materials are required to increase battery duration. The total cost of a given battery system is a function of the battery duration and battery capacity, and the assumed cost of each component.

To develop cost projections for battery storage, the SWE used the Mid Scenario cost projections from the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) Data for lithium-ion battery systems, released June 2019.[37] The NREL cost projection distinguishes between battery pack costs, denoted in $/kW, and a broader balance of system cost category that includes the inverter, other electrical equipment, and installation costs, denoted in $/kWh. Annual FOM costs are assumed to $33/kW per year for a 4-hour battery installed in 2021, or 2.5% of the capacity cost, and account for equipment replacement and other maintenance such that the battery system performs at rated capacity for lifetime.

Table 74 contains the cost assumption for each battery system component in 2021 and 2030, along with a description of costs included in each component. Overall, the installed cost of a four-hour lithium-ion battery system (not including FOM costs) is projected to decrease in cost from $403/kWh in 2018 to

---

[37] Obtained from https://atb.nrel.gov/electricity/2019/data.html. Documentation for the estimate is provided at https://www.nrel.gov/docs/fy19osti/73222.pdf.

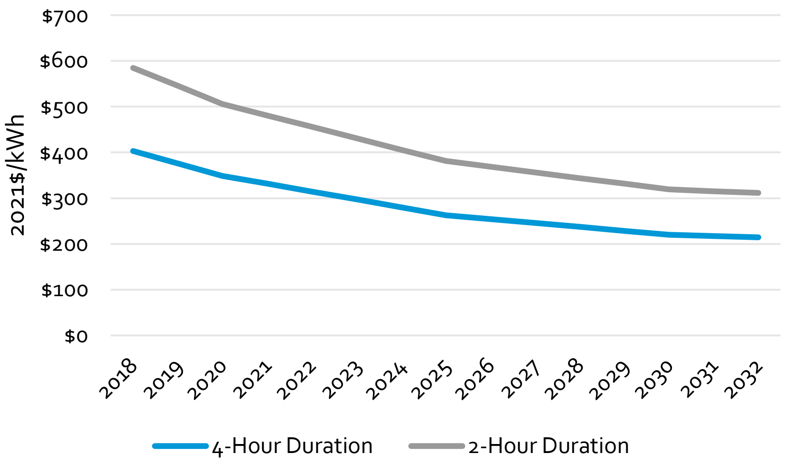
$332/kWh in 2021 and $220/kWh in 2030, which represents a 45% cost decrease between 2018 and 2030 and a 33% cost decrease between 2021 and 2030.

Table 74: Cost Assumptions Battery System Cost Component

Cost Component	2021 Cost Assumption (2021$)	2030 Cost Assumption (2021$)	Description of Costs Included
Battery Pack Capital Cost	$182/kWh	$121/kWh	Includes the overnight costs of battery cells and the battery management system
Balance of System Capital Cost	$597/kWh	$396/kWh	Includes the overnight costs of the inverter, other electrical equipment, and installation
4-Hour Battery Total Installed Cost	$332/kWh	$220/kWh	Includes Battery Pack and Balance of System costs, excludes Fixed O&M costs
Fixed O&M Costs	$33/kW (recurring annual)	$22/kW (recurring annual)	Includes the costs of battery replacement and other maintenance to guarantee that battery system performs at rated capacity for lifetime

The total installed battery system costs for two- and four-hour durations are displayed in Figure 13. Note that normalized on a per kWh basis, costs for a two-hour duration battery system are higher than for a four-hour system because a two-hour system will have a larger inverter. For example, a 100 kWh battery system with a four-hour duration may have a 25 kW inverter and discharge at an average rate of 25 kW per hour, while a 100 kWh battery with two-hour duration may have a 50 kW inverter.

Figure 13: Total Installed Costs for Lithium-Ion Battery Systems, by Duration



It is worth noting that there is a fairly wide range of battery price forecasts in the literature, and the NREL Mid forecast – which implies a 45% decrease in installed costs between 2018 to 2030 for 4-hour utility-scale battery systems – is in the lower-to-middle of the distribution of published cost projections.[38] By using the NREL cost projection, the SWE has also implicitly assumed that there is no cost premium for behind-the-meter storage, which is an optimistic assumption because larger installations can better spread out fixed costs (for instance, there are substantial differences between the total costs of utility-scale and behind-the-meter solar installations). For these reasons, and because the NREL ATB cost scenarios are recently published and widely used, the SWE believes the NREL Mid Scenario is an appropriate cost projection for behind-the-meter storage in Pennsylvania that is nonetheless in the lower range of projections.

8.2 BATTERY SYSTEM BENEFITS

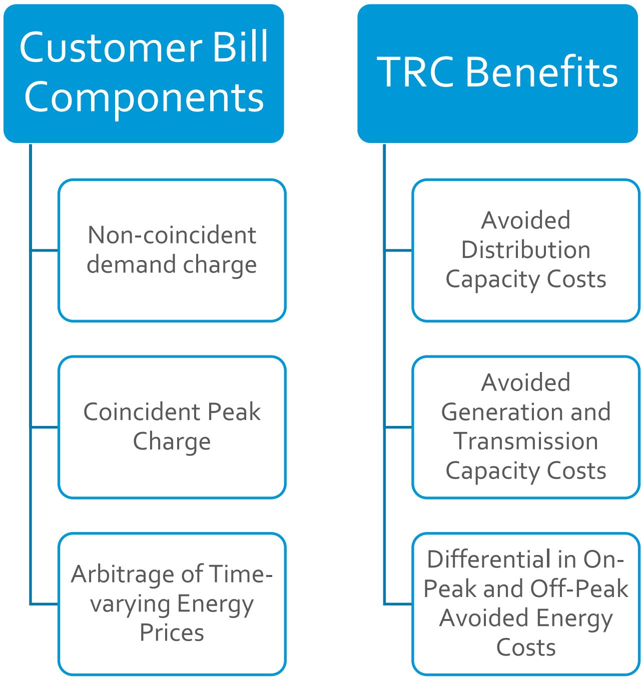
From a customer perspective, customer sited battery storage can offer multiple types of conceptual benefits, often referred to as the value stack. Customer benefits include both bill management and reliability benefits to the extent a system is appropriately sized to offer uninterruptible power supply or backup capabilities. Our focus is on the more tangible bill management benefits. For Pennsylvania non-residential ratepayers, bill management benefits include non-coincident demand charge reductions, avoided CP charges, and energy price arbitrage (for customers who face time-varying rates or market prices from their Electric Generation Supplier). Importantly, to achieve these benefits, there are two costs: the costs associated with the battery system and the increase in energy usage associated with charging and discharging batteries since some stored energy is lost with each charge cycle. This "round trip efficiency" is discussed further below.

As shown in Figure 14, each of these bill components are designed to recover utility costs. Although retail rates are roughly designed to collect revenue requirements for each of the avoided cost buckets in Figure 14, due to a variety of considerations, retail rates do not generally thoroughly reflect the magnitude or granularity of cost drivers for the TRC benefit categories. To the extent that deployed battery systems can avoid these costs, benefits can also be viewed from a TRC perspective, which is the focus of our analysis.

---

[38] *See* Figure 1 and Figure 3 of the NREL documentation report.

Figure 14: Customer Bill Components and Related Total Resource Cost Benefits



While the TRC benefit potential for battery storage is conceptually clear, there are limitations and technical considerations that limit the extent to which individual benefit streams can be realized and combined with other benefits. Essentially, two criteria must be met for benefits to be realizable and stackable. First, benefits accrue when peak loads are flattened or shifted. Customers with relatively flat loads do not have meaningful peaks to flatten. Similarly, energy arbitrage yields few benefits without peak loads to shift and without meaningful peak to off-peak price differentials. The second criterion pertains to benefit stacking. In order to realize benefits, a battery system must be allowed to cycle (e.g., charge off-peak and discharge on-peak). By definition, unless peaks for different benefit streams occur during overlapping hours, they cannot both be realized. For example, a dispatch pattern designed to reduce non-coincident demand might include charging overnight then discharging during typical monthly NCP hours to keep demand below a certain level. In the summer months when CPs typically occur, both CP and NCP load reductions can only be achieved if they occur during the same hours – typically mid- to late afternoon. Further, a long NCP, which requires shallower reductions over a longer duration, may preclude the deeper, shorter reductions, which would maximize CP reductions.

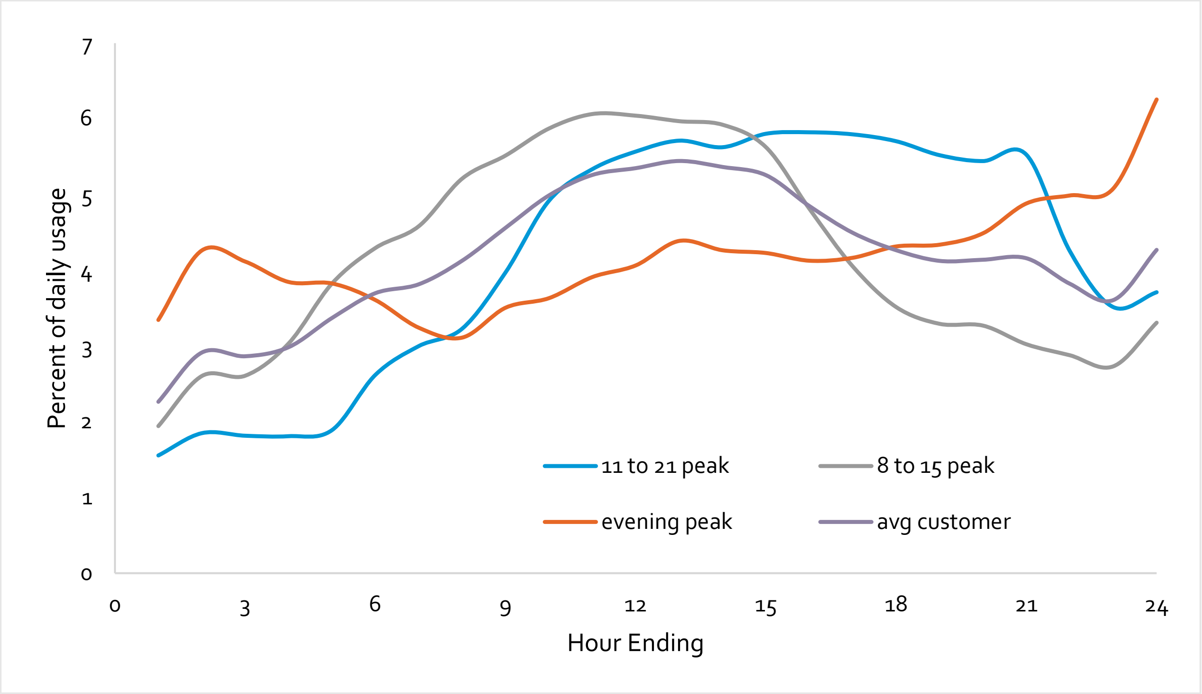
Figure 15 shows the average peak day load shape (in purple, dotted line) across a sampling of a few dozen small and medium non-residential customers pulled from the Phase III demand response participant population, pre enrollment. Loads shapes are shown for the average sampled customer, as well as for three load shape clusters: a ten-hour peak (blue), an earlier six-hour peak (grey), and a nearly flat load shape which peaks overnight. Non-coincident monthly peak load shapes are similar, albeit somewhat smaller in magnitude than these summer CP loads. The average peak is a roughly six-hour window, which falls somewhat before the CP hour, which typically falls in HE 17 or HE 18.[39] However,

---

[39] *See* https://www.pjm.com/-/media/planning/res-adeq/load-forecast/summer-2019-peaks-and-5cps.ashx?la=en.

underlying this shape are individual customer shapes that are more or less suited to battery storage. For example, to produce the same CP reduction, nearly twice the battery capacity would be needed for customers with the first load shapes (in blue) than for the second (in grey) because the peak reduction would need to be maintained for several more hours. Customers with the third load shape (in orange) have essentially no meaningful peak to flatten.

Figure 15: Coincident Peak Load Shape Clusters: Top Ten Hottest Days in 2016



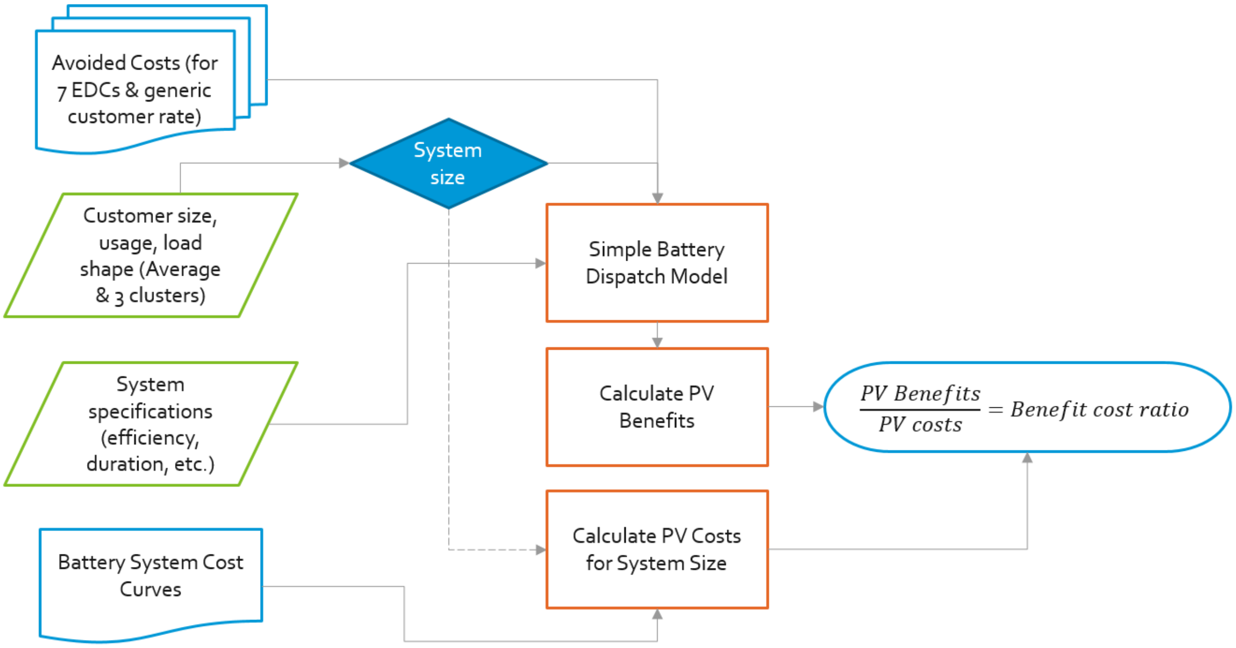
As described above, the cost to achieve load reductions is a function of the customer load shape. Far less battery capacity will be needed to achieve the same load reductions for a customer load shape with relatively short peaks. In addition, there are two technical limitations to the amount of load reduction a battery storage system can deliver. First of all, while a battery system has a nameplate capacity for kWh that can be stored by the system, there is always some amount of energy lost through the process of charging and discharging the battery. The percent of stored energy available for discharge is referred to as round trip efficiency and is typically about 84% for Lithium Ion systems. In practice, this means 16% of energy used to charge the battery off-peak is lost, resulting in increased energy usage overall. Further, only about 85% of nameplate capacity should be used for each charging cycle in order to preserve system capacity over its useful life.

8.3 METHODOLOGY

The purpose of the battery storage potential analysis was to understand both the net benefits given current avoided costs and battery storage system costs and then to identify future potential tipping points in terms of battery storage costs and avoided costs. One time equipment and installation costs and present value of recurring annual operations and maintenance costs over a ten-year lifetime were modeled using the costs described in Section 8.1 and laid out in detail in Section 4. Note that full avoided costs were used for modeling battery cost-effectiveness. Given that battery systems are a fully dispatchable, controllable resource, no performance adjustment was applied, in contrast to the modeling of avoided costs for demand response.

The SWE Team modeled present value of battery storage benefits over a ten-year lifetime using key parameters about NCP and CP usage derived from hourly loads for an illustrative small / medium non-residential customer, as described in Figure 15. The SWE modeled scenarios for the average sampled customer profile and for the three load cluster profiles. The SWE Team developed an illustrative battery dispatch model to quantify plausible benefit stacking, taking into account the constraints described above. The SWE selected a modeled battery system size to reduce CP by 50% during the three hottest months of the year; NCP reduction was modeled for the remaining nine months of the year. To assess cost-effectiveness across service territories, scenarios were modeled using TRC avoided costs for each of the six EDCs, as well as for a generic, small / medium non-residential rate designed to reflect typical rates. Figure 16 summarizes the model inputs, calculations, and outputs at the core of the model.

Figure 16: Battery Storage Potential Model



The SWE Team first modeled results with base case inputs for the average customer profile. The SWE then modeled sensitivity to input assumptions to identify key drivers of cost-effectiveness. The analysis tested sensitivity to customer profile, percent of CP reduced, overlap in dispatch months for coincident and NCP, and installation year (e.g., delayed installation to capture system cost reductions). Results were relatively robust to changes in these inputs.

The sensitivity analysis also explored sensitivity to increases in avoided distribution costs. The TRC costs modeled in the base case reflect the system wide average avoided cost of distribution for each EDC. However, distribution costs are typically driven by investments in a few geographically concentrated locations. These geographically concentrated avoided distribution costs can be multiples higher than system averages. As such, the sensitivity analysis modeled avoided distribution costs, which were several multiples above the system average avoided costs. Modeling sensitivity to changes of this magnitude did produce meaningfully different results.

8.4 RESULTS

Figure 17 summarizes modeled benefit cost ratios for the average customer profile using projected battery costs for 2021 across TRC cost scenarios and inputs. These ratios, denoted by the diamond markers in the bottom left hand corner, range from 0.25 to 0.6. Benefit cost ratios are higher for EDCs with higher avoided cost of distribution capacity values. Differences between the EDC TRC scenarios also reflect differences in other avoided costs. The differences are mostly explained by substantially lower avoided transmission capacity costs for West Penn, Penn Power, and PPL.

The avoided distribution cost sensitivity analysis is summarized by the diagonal lines in Figure 17, which show results when modeling higher distribution costs for a battery installed in 2021. This analysis answers the following questions: *(1) How do benefit cost ratios change in the face of higher, more concentrated avoided distribution costs? (2) At what level of avoided costs would battery storage become cost-effective?* The key conclusion of this sensitivity analysis is that battery storage installed in 2021 may be cost-effective in the presence of avoided distribution costs on the order of about $300 per kW-year. This breakeven cost ranges from $275 to $350 per kW-year across EDCs. It is highest for EDCs with the lowest avoided cost of transmission capacity.

Figure 17: Cost-Effectiveness as a Function of Avoided Cost of Distribution Capacity (2021 Installation)

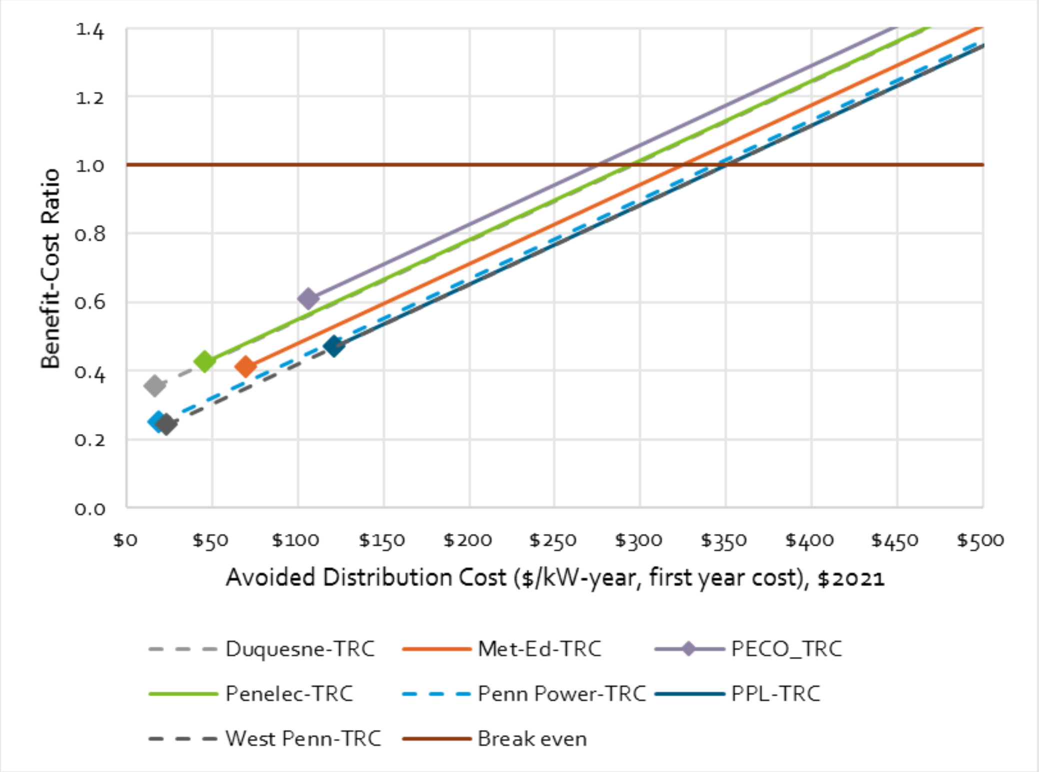
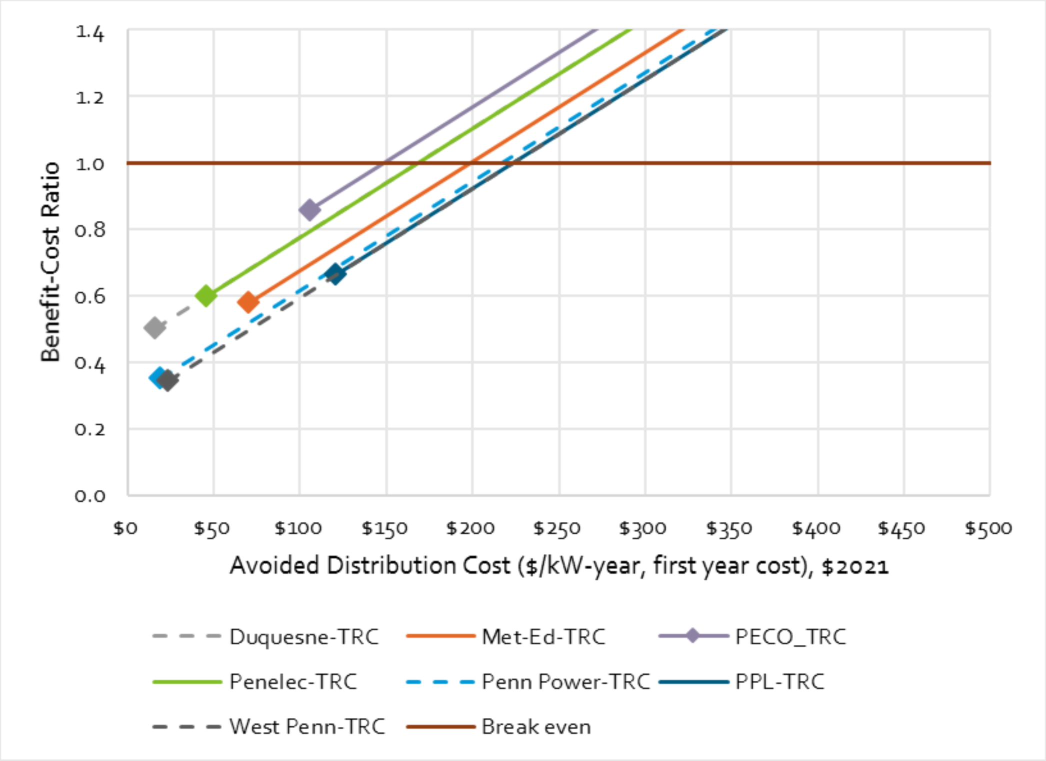


Figure 18 shows the results using the projected price of battery installations in 2030 and assuming that avoided costs are identical to those in 2021. This analysis answers the question: *How do TRC ratios change if the installed cost of batteries in 2021 was equal to the 2030 projected value ($220/kWh), rather than the 2021 value ($332/kWh)?* The key conclusion is that while the TRC ratio is still under 1 for all EDCs, the breakeven avoided distribution costs now range from roughly $150/kW-year to $225/kW-year. Battery prices would need to drop even lower in order to become cost-effective, assuming no change in avoided costs.

Figure 18: Cost-Effectiveness as a Function of Avoided Cost of Distribution Capacity (2030 Prices)



8.5 CONCLUSIONS

The battery storage potential analysis described above points to a few key conclusions:

- **Program intervention would be required to spur widespread adoption of behind the meter battery installation in Pennsylvania**. This is because, from the customer perspective, bill management benefits would typically be too low given current Pennsylvania rates to justify a battery investment. While some customers may highly value the uninterruptible power benefits batteries can also deliver, these reliability benefits are unlikely to produce an acceptable payback calculation in most cases.
- **Battery storage is not projected to be cost-effective during Phase IV of Act 129**. Given current cost projections and system average avoided costs, TRC ratios are on the order of 0.25 to 0.6 across the Commonwealth. Ratios are lower where the avoided cost of transmission and distribution capacity values are lower. The cost takes projected battery cost declines into

account and is on the lower end of the literature; nonetheless, battery system costs are not declining fast enough to meaningfully change this result.

- **Cost-effectiveness may be achieved in the presence of avoided distribution costs on the order of $300 per kW-year**. This is far above system average avoided costs. However, this may be achievable in certain locations where large capital investments are being considered to address load growth. The breakeven point ranges from $275 to $350 per kW-year and is lower where avoided transmission costs are higher.
    - At projected 2030 battery costs the breakeven point ranges from $150 to $225 per kW-year. This level of avoided cost of distribution capacity is common in areas experiencing load growth that will require capital upgrades.
- **Targeted battery storage applications could achieve cost-effectiveness**. For EDCs with the highest system average avoided distribution costs (PPL and PECO), the breakeven avoided costs are two to three times the average system wide avoided distribution costs. However, because avoided distribution costs are typically geographically concentrated in key load pockets, battery storage could be cost-effective in a few, targeted, high value load pockets.
- **Even at breakeven distribution cost levels, program intervention would need to cover most of the customer's costs for behind the meter battery storage**. Though targeting batteries in a few high value areas could make sense from a TRC perspective, simply achieving breakeven cost-effectiveness (TRC ratio = 1) would still result in a customer payback period of over ten years. Most batteries have a useful life of ten years, so a measure with a payback period longer than the EUL would never recover upfront costs. The SWE's 2018 Non-Residential Baseline Study[40] found that most non-residential customers seek payback periods of one to four years. For a battery installation to make sense from a customer perspective, nearly 100% of the cost of the battery would need to be covered by incentives, even at breakeven TRC avoided cost of distribution capacity levels of around $300 per kW-year.
    - EDC installation of utility-scale batteries at strategic locations where capital projects can be avoided or deferred is likely the more straightforward mechanism to realize the system benefits batteries offer for managing peak demand.

---

[40] *See* the 2018 Pennsylvania Non-Residential Baseline Study, Chapter 13 – Willingness to Pay, at http://www.puc.pa.gov/Electric/pdf/Act129/SWE-Phase3_NonRes_Baseline_Study_Rpt021219.pdf.

APPENDIX A – TABLE OF ACRONYMS

Table 75 lists each of the acronyms used in this report and the phrase it is used to represent.

Table 75: Table of Acronyms

Acronym	Phrase
API	Application Programming Interface
APS	Allegheny Power Systems
ASHP	Air Source Heat Pump
ATSI	American Transmission Systems, Inc.
BDR	Behavioral Demand Response
BOS	Balance of System
BRA	Base Residual Auction
BYOT	Bring-Your-Own-Thermostat
CAC	Central Air Conditioner, or Central Air Conditioning
C&I	Commercial and Industrial
CP	Coincident Peak
DLC	Duquesne Light Company
DR	Demand Response
DRIPE	Demand Reduction Induced Price Effects
DSA	Demand Side Analytics, LLC
DSM	Demand Side Management
EDC	Electric Distribution Company
EE	Energy Efficiency
EE&C	Energy Efficiency and Conservation
EFLH	Equivalent Full Load Hours
ELCC	Effective Load Carrying Capacity
ELRP	Emergency Load Response Program
EPC	Engineering, Procurement, and Construction
ESF	Energy Savings Factor
FE: ME, Met-Ed	First Energy Metropolitan Edison Company
FE: PN, Penelec	Pennsylvania Electric Company
FE: PP, Penn Power	Pennsylvania Power Company
FE: WPP, West Penn	West Penn Power Company
FOM	Fixed Operation and Maintenance
GT&D	Generation, Transmission, and Distribution

kW	Kilowatt
kWh	Kilowatt Hour
LCI	Large Commercial and Industrial
MAP	Maximum Achievable Potential
MW	Megawatt
MWh	Megawatt Hour
NCP	Non-Coincident Peak
NMR	NMR Group, Inc.
NREL	National Renewable Energy Laboratory
PECO	PECO Energy Company
PJM	PJM Interconnection, LLC
PLC	Peak Load Contribution
PNNL	Pacific Northwest National Laboratory
PPL	PPL Electric Utilities Inc. Company
PSA	Peak Shaving Adjustment
PUC	Public Utility Commission
PVNB	Present Value of Net Benefits
PY	Program Year
RAP	Realistic Achievable Potential
RCP	Resource Clearing Price
RTO	Regional Transmission Organization
SCI	Small Commercial and Industrial
SODRSTF	Summer Only Demand Response Senior Task Force
SWE	Statewide Evaluator
THI	Temperature Humidity Index
TRC	Total Resource Cost
TRM	Technical Reference Manual