



Demand Side Analytics
DATA DRIVEN RESEARCH AND INSIGHTS

REPORT

Summer Peak Shaving Adjustment Resources in PJM



Prepared for CAPS
By Demand Side Analytics, LLC
March 2019

PREPARED BY

- Jesse Smith, Principal Consultant
- Adriana Ciccone, Senior Consultant
- Ross Beppler, Quantitative Analyst

TABLE OF CONTENTS

1	PJM Summer Only Demand Response Task Force Outcomes.....	3
1.1	LOAD FORECAST ADJUSTMENT	3
1.2	DESIGN COMPONENTS AS ADOPTED.....	4
1.3	TIMELINE	6
2	Peak Shaving Resource Offer Strategy	7
2.1	WEATHER	8
2.2	SYSTEM LOAD CHARACTERISTICS	10
2.3	CUSTOMER ROTATION.....	13
3	Valuation of Peak Shaving Adjustments	14
3.1	THE ECONOMIC THEORY OF CAPACITY PRICE SUPPRESSION.....	14
3.2	MODELING OF PJM BRA SENSITIVITY ANALYSES	15
3.3	AVOIDED COST OF TRANSMISSION AND DISTRIBUTION CAPACITY	19
4	Conclusions and Recommendations	20

Figures

Figure 1: VRR Curve with Peak Shaving Adjustment	4
Figure 2: Sample Program Decision Chart.....	8
Figure 3: Distribution of Average Number of Summer Events by THI Trigger.....	9
Figure 4: Distribution of Events by Month and Zone	10
Figure 5: Peak Forecast Impact as a Share of Shaving Amount by Zone.....	11
Figure 6: Weather Sensitivity of Select PJM Zones	12
Figure 7: System Load Characterization.....	13
Figure 8: Price Suppression Example.....	15
Figure 9: RTO Capacity Supply Curve Slope Estimation from BRA Scenario Analysis 2021/2022	16

Figure 10: Supply Curve Slope Approximations from RTO Base Residual Auction Scenarios by Year	17
Figure 11: Supply Curve Slope Approximations from EMAAC Base Residual Auction Scenarios by Year 17	
Figure 12: Distribution of Events for Cool, Average, and Hot Summers – 81 THI Threshold.....	22
Figure 13: 600 MW Shaving Program with Three Hour Events – ATSI Zone.....	23

Tables

Table 1: Peak Shaving Adjustment Program Design Components	5
Table 2: Hypothetical PSA Value Calculation	18
Table 3: THI Thresholds for a Mean of 24 Shaving Hours per Summer	21

1 PJM SUMMER ONLY DEMAND RESPONSE TASK FORCE OUTCOMES

At its October 25, 2018 meeting, the Markets and Reliability Committee of PJM voted in favor of a motion to adopt PJM's proposal for creation of a Peak Shaving Adjustment mechanism. The proposal was the result of work by the Summer Only Demand Response Task Force (SODRSTF) which sought to explore mechanisms to include summer only DR resources in PJM's forward capacity market (Reliability Pricing Model, or RPM). Historically demand resources such as demand response and energy efficiency have entered the market as supply and been eligible to compete alongside traditional supply side resources (power plants) in a competitive auction to fulfill the resource requirements for the region.

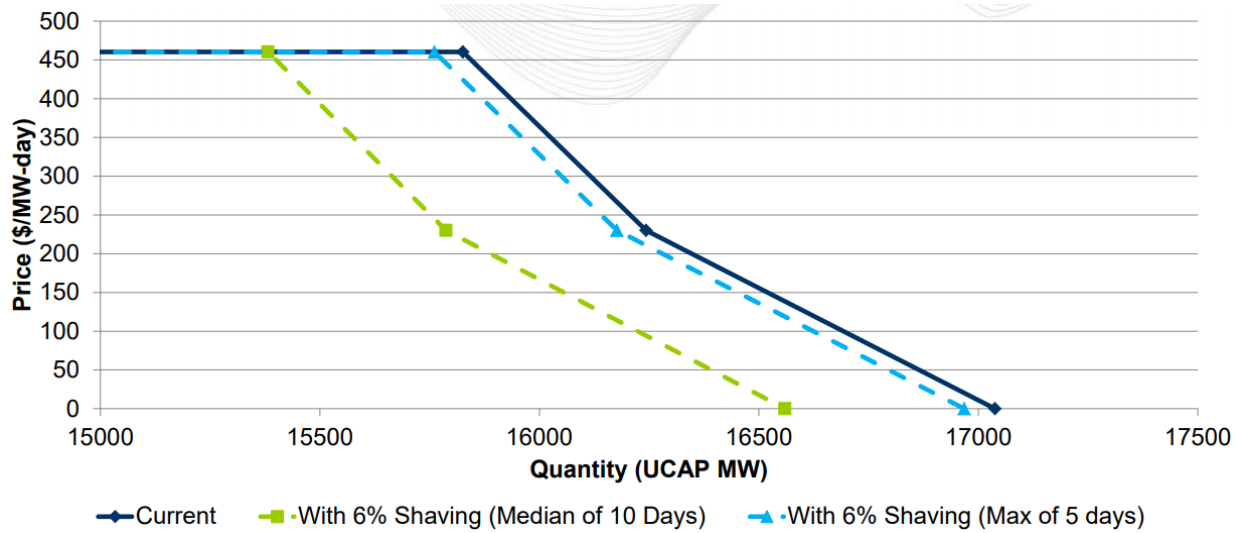
Demand response resources such as utility direct load control of central air conditioners have recently encountered difficulty participating in the market due to PJM's "capacity performance" definition of generation capacity. Capacity Performance, or CP resources, must be able to perform 16 hours per day for consecutive days on any operating day regardless of season, weekends, or holidays. While summer only resources could theoretically pair with a winter only resource to form a bid, EDCs and LSEs with existing summer only DR resources perceived the move to Capacity Performance would lead to stranded summer assets in a summer-peaking system. The SODRSTF charter directed the task force to explore mechanisms to value demand response for those resources that may not be able to clear in the capacity 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 include key elements of other packages and ultimately received 65% support from the task force.

1.1 LOAD FORECAST ADJUSTMENT

A Peak Shaving Adjustment (PSA) is fundamentally different from the way demand response has participated in RPM historically. Instead of being treated as supply that is capable of fulfilling resource requirements, a Peak Shaving Adjustment enters the market on the demand side. In PJM's capacity market, demand is represented by the Variable Resource Requirement (VRR) curve. As shown in Figure 1, the VRR curve is downward sloping. The resource clearing price is ultimately the coordinates on the y-axis (price), where the supply curve – which is upward sloping – intersects the demand curve. Figure 1 also shows the underlying mechanism by which Peak Shaving Adjustments will be recognized in the market. Once recognized by PJM, Peak Shaving Adjustments will lower the peak load forecast for a zone and move the VRR curve to the left.

Figure 1: VRR Curve with Peak Shaving Adjustment



The amount a Peak Shaving resource will lower the summer peak load forecast and move the VRR curve the left is a function of several factors.

- The amount of load reduced when active (MW)
- The frequency of shaving (number of days per summer)
- The duration of shaving (number of hours per day)

Zonal load characteristics also affect the magnitude of the load forecast adjustment and are discussed in more detail in Section 2.1. The load forecast adjustment itself is calculated by PJM using the difference in two forecast models.

1. Traditional econometric load forecast using historic loads, weather, and other factors
2. The same model with a modified load history. Using the attributes provided by the program administrator, PJM will subtract the expected shaving from historic loads back to 1998 and re-run.

1.2 DESIGN COMPONENTS AS ADOPTED

Table 1 summarizes the key design components of the Peak Shaving Adjustment mechanism. The table is adapted from a [proposal matrix](#) compiled by PJM to compare packages in the SODRSTF.

Table 1: Peak Shaving Adjustment Program Design Components

Design Component	Description
Mechanism to recognize summer only DR	Forecast Adjustment based on load forecast run for BRA with modified load history that assumes anticipated curtailment behavior occurred in the past. VRR curve is reflective of the reliability requirement, which depends on the load forecast and the monthly load profile.
Measurement and Verification (M&V)	Economic DR rules, which use a customer baseline (CBL). CBLs use average load data from recent non-event days to estimate what load would have been absent curtailment. The default CBL is a “high 4 of 5” with SAA. PJM Manual 11 provides a full list of potential CBLs.
Non-Performance Penalties	Modification to forecast adjustment based on most recent performance. If a resource under-performs relative to its commitment, subsequent commitments will be de-rated.
Curtailment Trigger	Temperature Humidity Index (THI) as determined by the program administrator. This is different from traditional DR in that there is no event “call”. The program administrator must monitor weather conditions and determine whether to shave or not based on the weather forecast. The THI trigger is a daily maximum – actual, not forecasted. Section 2.1 includes addition discussion of weather considerations.
Capacity Market Valuation	Function of the lower forecast and shifting the VRR curve left. No compensation is provided. The zone only lowers the amount of capacity they are obligated to purchase (an avoided payment). All benefits accrue to the zone in the form of a reduced capacity obligation.
Supervisory Control	Program Administrator (EDC, LSE, CSP, State or Other) is fully responsible to fulfill the load forecast adjustment requirements. Program Administrator manages a portfolio of customers under an approved Relevant Electric Retail Regulatory Authority (RERRA) tariff or Order.
Performance Months	Pre-determined. Program administrators can select any active months they wish and communicate that to PJM. Affects the valuation.
Interruption Days	Unlimited. Any non-holiday weekday in the performance months
Interruption Hours	Pre-determined. Program administrator decides which hours they will shave load on days the THI trigger is met and communicates that to PJM. Affects valuation.
Eligibility	Load reduction programs governed by tariffs/orders. Dual participation in supply-side DR (Economic or Load Management) or PRD is not allowed.
Timeline for reporting program components to PJM	10 business days prior to September 30 th . Timeline is adjusted for transition period (see Section 1.3)
Applicable Auctions	Base Residual Auction and Incremental Auctions

The design components listed in Table 1 were not unanimous and alternate structures will likely be proposed until all rulemaking is final at PJM and FERC. The two areas that received the most attention during the SODRSTF meetings were:

- 1) **Eligibility** – several package sponsors sought alternatives to the PJM package design that disallows participation as both supply and demand in the market.
- 2) **Supervisory Control** – some package sponsors felt that specifying Program Administrators must manage customers under RERRA tariff or Order was too restrictive and would limit access to Peak Shaving Adjustment market opportunities.

All of the components in Table 1 are important for states and program administrators to understand and consider when nominating a Peak Shaving Adjustment. The prohibition of dual participation may prove especially important for some states. While residential customers do not participate in supply-side DR absent aggregation by EDCs or program administrators, large C&I customers do. For example, Pennsylvania's Act 129 demand response programs deliver 450-500 MW of peak shaving on hot summer afternoons. However, many of the large industrial customers that participate in this state program also have commitments in PJM DR programs (as supply). Regulators and EDCs in Pennsylvania would have to carefully consider the amount of *eligible* peak shaving capability in existing programs before nominating a Peak Shaving Adjustment.

One issue we expect will require additional clarification moving forward is the eligibility of peak demand reductions associated time-varying pricing (TVR). Peak time rebates (PTR) are a dispatchable type of rate and were discussed in the SODRSTF as eligible. We believe event-based price signals such as critical peak pricing (CPP) would also be eligible. The case for new 'everyday' time-of-use rates or residential demand charges is less clear. Certainly these strategies provide a price signal to shave peak demand, but they are not dispatchable. A downward adjustment in the peak demand forecast seems like a logical place to reflect the expected effects of TVR, but PJM will need to determine how long such deployments are considered a load forecast adjustment and at what point they become embedded in the default load forecast.

1.3 TIMELINE

The commitment cycle for Peak Shaving Adjustments (PSAs) will precede the Base Residual Auction for generation capacity. The BRA for a delivery year is held in the spring, three years prior to the delivery year. For example, the BRA for the 2021/2022 delivery year (June 1, 2021 to May 31, 2022) was held in May 2018. The BRA for the 2022/2023 delivery is delayed until August 2019 because of FERC filings so the Peak Shaving Adjustment timeline is different as it is phased into place. Once the transition period is complete, PSAs will need to commit by the September prior to the BRA – or almost four years before the delivery year. Key dates for the 2022/2023 delivery year are:

- **December 2018** – PJM releases its 2019 Peak Load Forecast. This forecast will not reflect any adjustments for Peak Shaving
- **February 1, 2019** – PSA program parameters must be submitted to PJM

- **March 15, 2019** – PJM publishes a new Peak Load Forecast inclusive of Peak Shaving Adjustments
- **May 1, 2019** – Planning parameters for the 2022/2023 BRA are posted online
- **August 2019** – Base Residual Auction of the 2022/2023 delivery year occurs
- **June 1, 2022** – Beginning of the 2022/2023 delivery year. PSAs nominated in February 2019 are expected to perform when the THI trigger is met.

The timeline listed above may ultimately be delayed as FERC approval of the PJM proposal has not been finalized. In February 2019, FERC issued a letter of deficiency to PJM citing the need for additional clarity on several topics. This development has timeline implications because it reopens the filing for member comments and also allows for time periods for PJM to address the topics and for FERC to review.

Specifics aside, a key aspect of this timeline is that 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 will have to look at historic clearing prices and base decisions to commit on estimate values. There is no mechanism to withdraw a commitment based on price, other than non-performance.

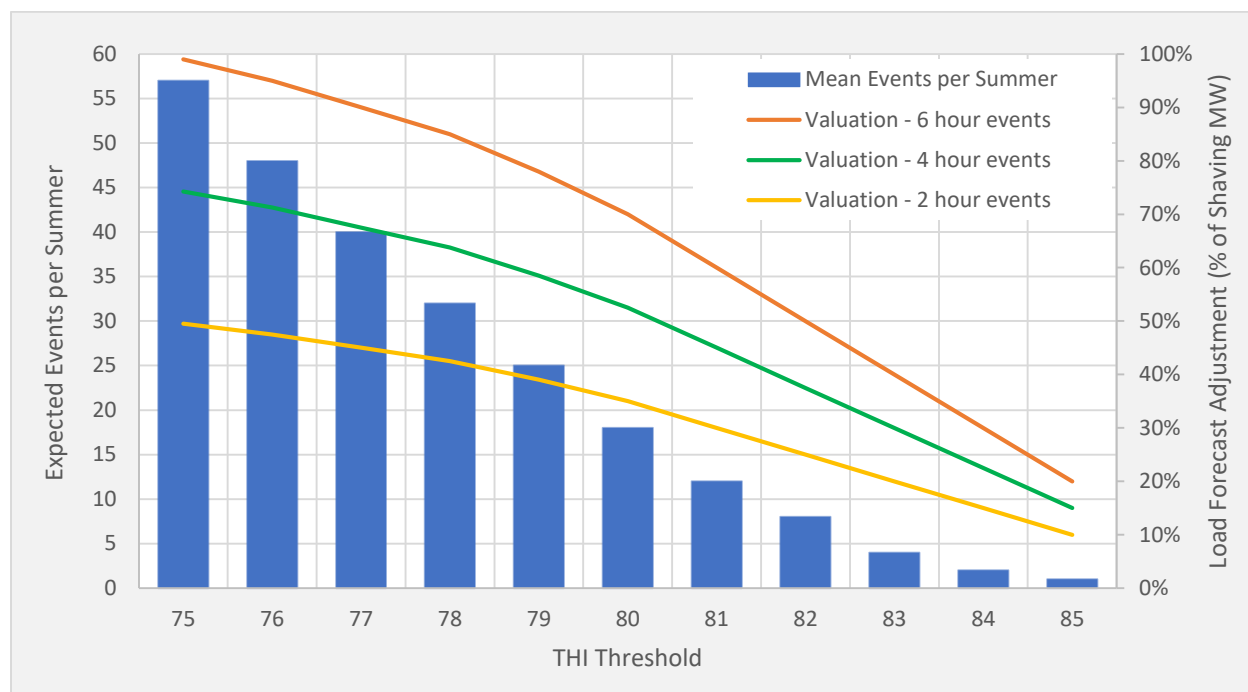
Another key takeaway from the timeline shown above is that PSAs must commit well in advance of delivery. This can create challenges for utility or state planning cycles which sometimes set program plans, budgets and goals in 3-5 year cycles, but only plan 1-2 years in advance. As shown in Table 1, PSAs can also commit in Incremental Auctions, but clearing prices in Incremental Auctions have been lower than BRAs historically.

2 PEAK SHAVING RESOURCE OFFER STRATEGY

The valuation of a Peak Shaving Adjustments will be dependent on the magnitude, frequency, and duration of peak shaving. A program administrator that commits to shave 100 MW for two hours per day on summer weekdays with a maximum THI of 84 might receive a 20 MW reduction in their summer peak load forecast and reliability requirement. If the same program administrator were to commit to shave 100 MW for six hours per day each weekday the maximum THI exceeded 78, the zone might receive an 80 MW load forecast adjustment.

Figure 2 illustrates the fundamental decision a program administrator must make when nominating a PSA resource. Along the x-axis is THI. The blue bars show the expected number of peak shaving days per summer at each THI trigger and are based on 20-year averages for a hypothetical zone. Of course not every year exhibits average weather. The orange, green, and yellow lines represent the valuation of a PSA for given event duration. The valuation percentages can be thought of as the percentage of a resource clearing price the PSA earns. Consider a 100 MW PSA that is allocated a 60 MW reduction in resource requirement (60%) for a delivery year where the resource clearing price is \$100/MW-day. That 100 MW peak shaving program is valued at 60% of the clearing price, or \$60/MW-day.

Figure 2: Sample Program Decision Chart



The height of the blue bars is a function of weather conditions which have to be estimated based on historic data. Section 2.1 explores the risks and decision criteria associated with weather. The shape of the orange, green, and yellow lines illustrated in Figure 2 for a given zone is also a function of zonal load characteristics. This is explored in more detail in Section 2.2.

2.1 WEATHER

Peak Shaving days will be identified based on the maximum Temperature-Humidity Index (THI) that a system reaches on any given summer weekday. Program administrators must select a THI threshold for their Peak Shaving program and must dispatch the program whenever that THI threshold is met. This design has uncertainty associated with it, and administrators should understand how weather variability affects program operations. There are two main types of uncertainty related to weather that should be considered:

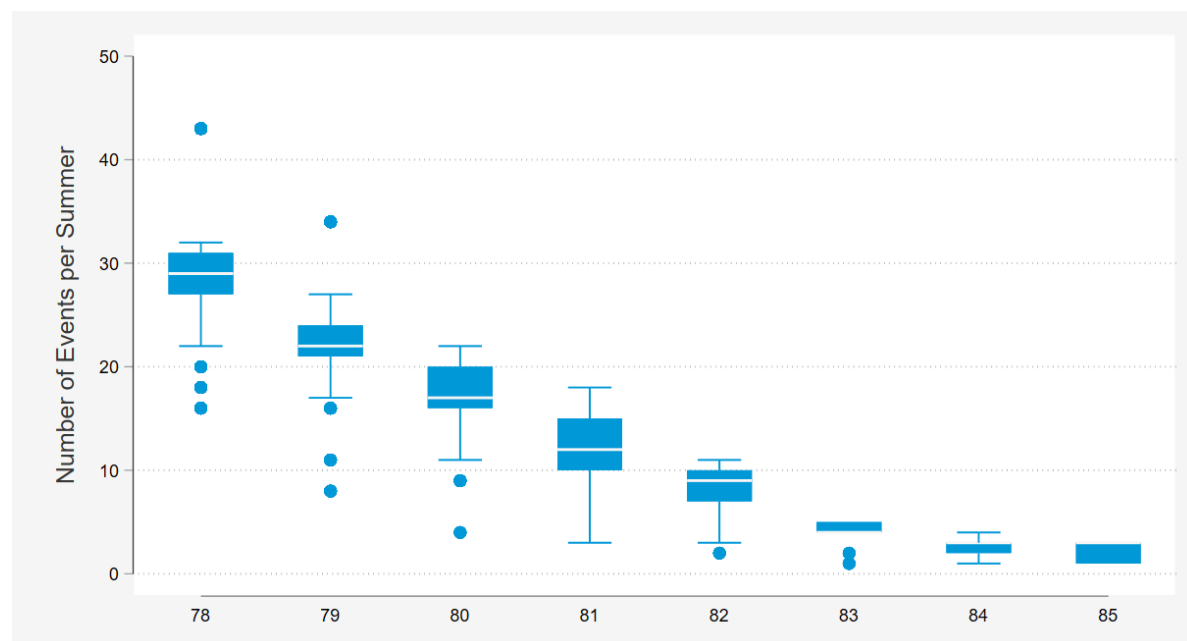
- Weather forecasts are not error-free. For example, during summer months in the Mid-Atlantic region, afternoon thunderstorms can lead to lower observed THI values compared to forecasts.
- Observed weather varies from year to year. Whether a summer will be a hot or mild summer cannot be known in advance.

Without a detailed study of weather forecast accuracy, it is difficult to say what the impact of forecast error would be on program dispatch. Program administrators should consider if setting an internal THI trigger lower than the committed trigger to avoid missing a shaving day if the observed THI is higher

than forecasted. Since a lower THI threshold would mean more events, which can have customer incentive and participation implications, program administrators should weigh these costs against any penalties for underperformance. Program administrators will also need to consider when to make “go/no-go” decisions regarding peak shaving. Waiting as close as possible to the committed shaving hours will reduce uncertainty, but also limits the opportunity for “pre-cooling” of homes for programs that shave via control of central air conditioning loads.

Year-to-year variations in weather are easy to understand using historic data. Figure 3 shows the distribution of events per summer for the JCPL (Jersey City Power & Light) system across a range of THI triggers. This graph is a box-and-whiskers plot that illustrates the distribution of a given metric – in this case the number of event days per summer (based on weather data from 2006 to 2017). The height of the blue rectangle (box) illustrates the range of the 25th through 75th percentile of event days per summer, so for example we can see that 50% of summers would have between about 10 and 15 events per summer if the THI trigger had been set to 81. The median outcome in that example is where the line in the middle of the blue rectangle is, or about 12 shaving days per summer. The more salient values from the chart, however, are the minimum and maximum observations that are shown either as the minimum and maximum range of the whiskers, or as the points outside the whiskers, which are classified as outliers. So while, with a THI of 79, the JCPL system experiences a median of 22 events per summer, the lowest number of peak shaving days per summer that would have been observed in this twelve-year period was 8 peak shaving events. Perhaps most importantly for program planners, the highest year would have had 35 shaving events.

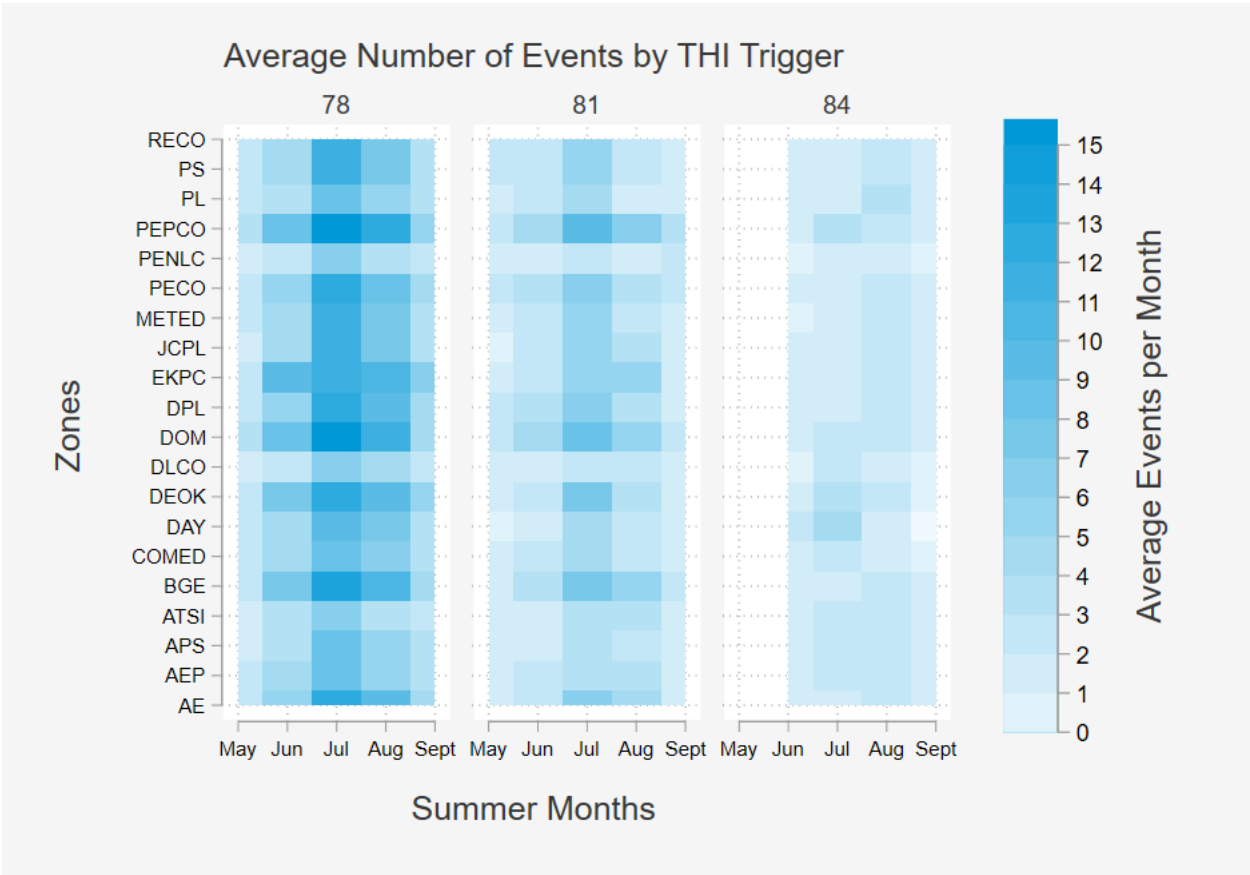
Figure 3: Distribution of Average Number of Summer Events by THI Trigger



What this means for program administrators is that, while a program may be designed at a particular THI trigger to yield an average or median number of events in a summer, the intrinsic variability in year-to-year weather variability will result in unpredictable numbers of events.

Complicating these decision points further, this variability is not necessarily evenly distributed throughout the summer. Figure 4 shows the average number of events per month across all PJM zones and summer months. Naturally, the hotter and more humid months of July and August trigger more shaving events at any THI threshold, and the higher the threshold, the fewer events there are overall. However, such intra-seasonal variability may have effects on participation. It is one thing to enroll in a program that is expected to deliver 20 events per summer, however it may be another to have half of them triggered in a single month.

Figure 4: Distribution of Events by Month and Zone

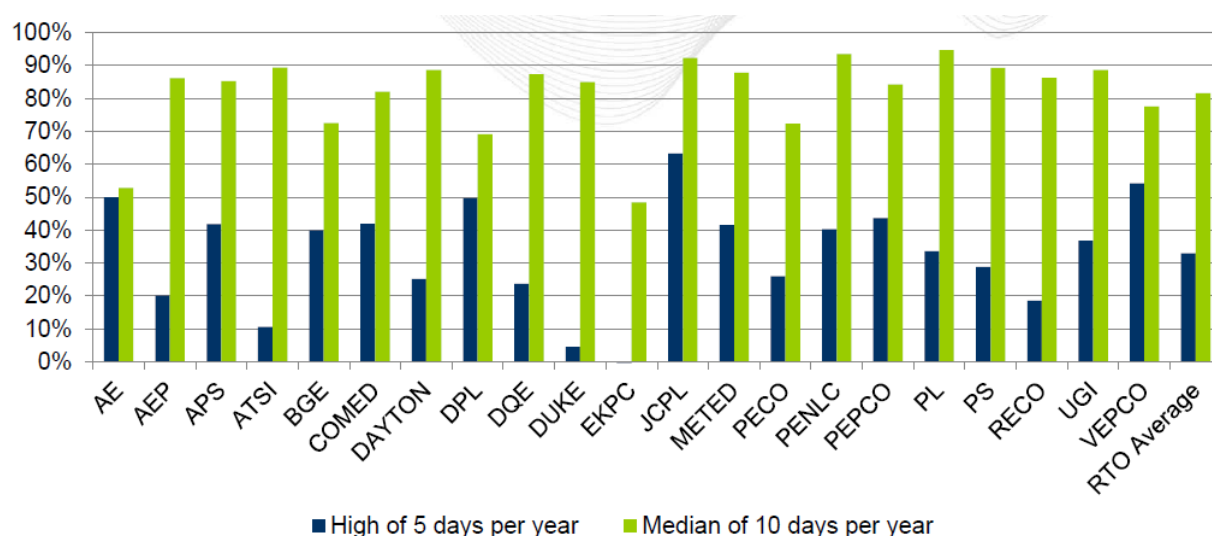


2.2 SYSTEM LOAD CHARACTERISTICS

Not every system will have the same peak load forecast impact given the same program design. Due to unique characteristics for each zone, a program that shaves for 5 days a summer in JCP&L will have a higher impact on the peak load forecast than nearly any other system in PJM, as shown in Figure 5. Similarly, the difference in forecast impact between a program that shaves for a maximum of 5 days per summer compared to one that shaves a median of 10 days per summer can vary by system. These

differences are motivated by system load characteristics that make each territory unique. In this section, we examine the key drivers of peak load forecast impact, and what design features of a peak shaving program affect impacts.

Figure 5: Peak Forecast Impact as a Share of Shaving Amount by Zone

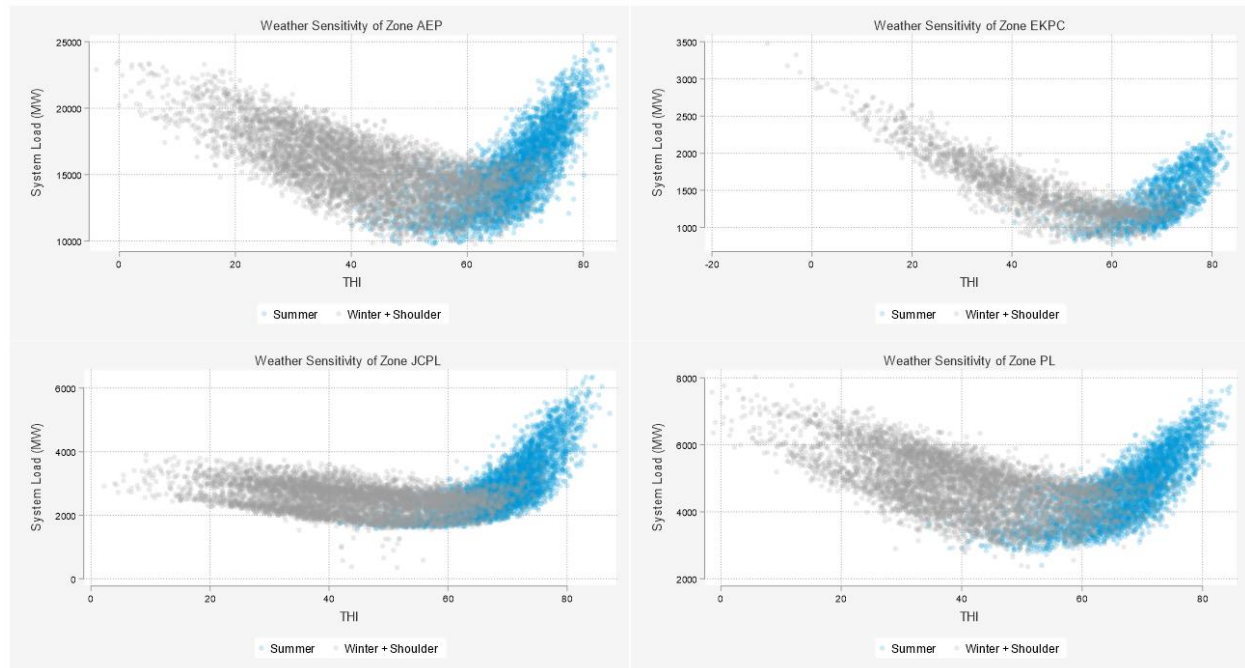


Every system in PJM has slightly different characteristics, due to its size, weather, diversity of industry and residential composition. These differences have meaningful implications for the ability of a summer peak shaving program to lower the reliability requirement for the zone. To assess the value of such a peak shaving program, we should first consider two important interactions between the system and the program:

- 1) Does the system typically peak when summer peak shaving events would be called?
- 2) Will the peak shaving activity create a new peak or broaden the peak substantially and spread risk across other days and hours when shaving does not occur?

The first question can be considered in two ways. First, does the system even peak in the summer, when the peak shaving program is operational? Is the zone a summer-peaking, winter-peaking, or dual peaking system? Second, for a given THI trigger, is the system at its peak demand? That is, if an event is called, what is the likelihood that the system is at its peak? Figure 6 shows how these characteristics can change by zone. On the y-axis is an hourly system load for one of four systems for calendar year 2017. The x-axis shows the THI in that interval. Finally, the markers are color coded for summer/non-summer months. For some systems, the maximum system load occurred in the summer, such as AEP (American Electric Power) and JCPL (Jersey City Power & Light). EKPC (East Kentucky Power Cooperation) clearly peaks strictly in the winter, while PL (PPL) is relatively balanced in peaking between summer and winter and the season the peak occurs may vary from year to year based on weather.

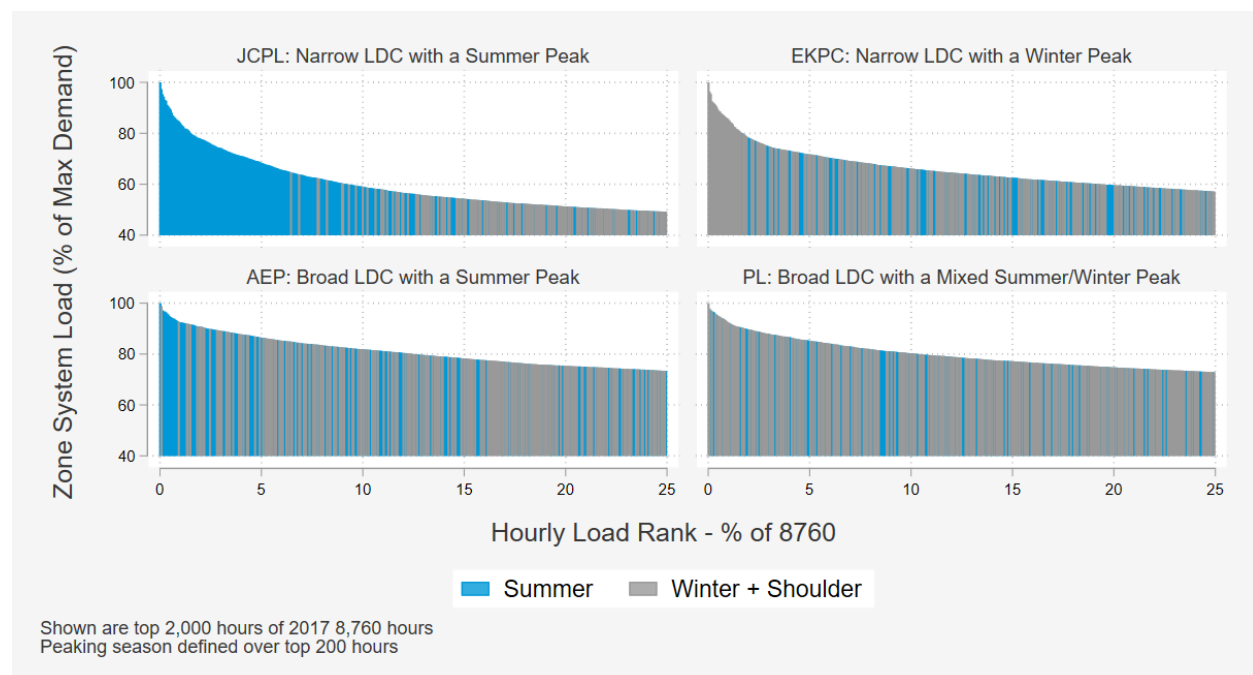
Figure 6: Weather Sensitivity of Select PJM Zones



Systems that peak in the summer will be allocated more value from a summer-only DR program, as demand reductions will reduce the overall system peaking risk and generation capacity requirement for the zone. Figure 6 also shows differing levels of variability in system load at a given THI. AEP and JCPL are both summer-peaking systems, however at a given THI, AEP has a much broader range of observed system load than JCPL. Similarly, we see AEP loads at or near the maximum system load for the year at several degrees lower than the observed maximum THI. Based on these characteristics, we'd expect the same amount of peak shaving based on a THI threshold to yield a smaller reduction in the peak load forecast than for JCP&L.

To assess the second question, it is also helpful to look at a system's load duration curve (LDC). The LDC ranks system load in descending order, and in some cases normalizes it to be compared to other systems. Shown below in Figure 7 are normalized load duration curves for four illustrative PJM systems. The y-axis is defined as the % of the maximum demand in that year and the x-axis is the rank of each hour-long interval as a percent of the 8,760 hours in a year. Each interval is color-coded in either blue or grey to indicate which season that interval comes from – either Summer (May – September) or Winter & Shoulder (all others). As discussed above, both Jersey City Power & Light and American Electric Power peak in the summer months, while East Kentucky Power Cooperative peaks in the winter and PPL peaks in both summer and winter. This has important considerations for peak shaving program design and valuation, since a program designed to shave summer peak load will be less impactful on resource requirements in a system where significant peaking risk occurs outside of the summer months.

Figure 7: System Load Characterization



Another load characteristic to consider is whether a peak shaving program would simply shift the peak to earlier or later hours during an event day. That is, if the event window is short, there still may be high demand before the event or after the event is over. This is one of the key consideration with event duration and why the three lines in Figure 2 exhibit different valuation trends. The idea of secondary peak creation is best illustrated by the breadth of the load duration curve over the top 5% of hours: the broader the peak, the smaller the difference in demand is between the system peak hour and the 95th percentile. Said another way – if demand is shaved during the top 1% of hours but the load duration curve is broad, the hours in the top 2%-5% of intervals may be close enough to peak that the peaking risk has effectively been shifted to them rather than eliminated. On the other hand, a narrow peak, like at JCP&L or EKPC in the figure above will reap benefits from a peak shaving program since peak load is not likely to be shifted to near-peak hours. Of course, since East Kentucky Power Cooperative peaks in the winter, this second consideration is moot for that system.

To address this issue, programs could be designed with long durations that essentially capture the entire peak on a given day. Program administrators must consider the effect on customer incentives, satisfaction, and participation that such a long event window would have in conjunction with system characteristics.

2.3 CUSTOMER ROTATION

Another important consideration for program administrators will be whether to use customer rotation to shave load on more days or for a greater number of hours per day. Consider an air conditioning cycling program that has 100,000 residential participant households that achieve an average load reduction of 1.0 kW (100 MW resource). Historic utilization of the program has been fairly infrequent

with 4-6 events per summer lasting 3-4 hours per event. Is it more advantageous from a valuation perspective for the EDC to commit on of the following designs?

- 100 MW of peak shaving at THI = 83 during hours ending 16, 17, and 18
- 50 MW of peak shaving at THI = 81 during hours ending 15, 16, 17, 18, and 19
 - And during any given peak shaving hour only dispatch half of the program participants

These two designs would likely result in a similar number of interruption hours per participant. The second design would clearly receive a higher valuation *per MW* from PJM because of the greater number of hours and lower THI threshold. However, the EDC can only commit to shaving half as many MW. How would the total valuation compare? We believe the answer to this question will be a function of how broad/narrow peaks are for zonal load. For a peaky system, it may be advantageous to shave more MW at extreme THI conditions for a small number of hours. For a system, with a flatter peak it may be advantageous to sacrifice the amount of shaving in any given hour to peak shave on more days and hours. PJM may be willing to run a small number of permutations during the transition period as program administrators try to optimize their offer strategy.

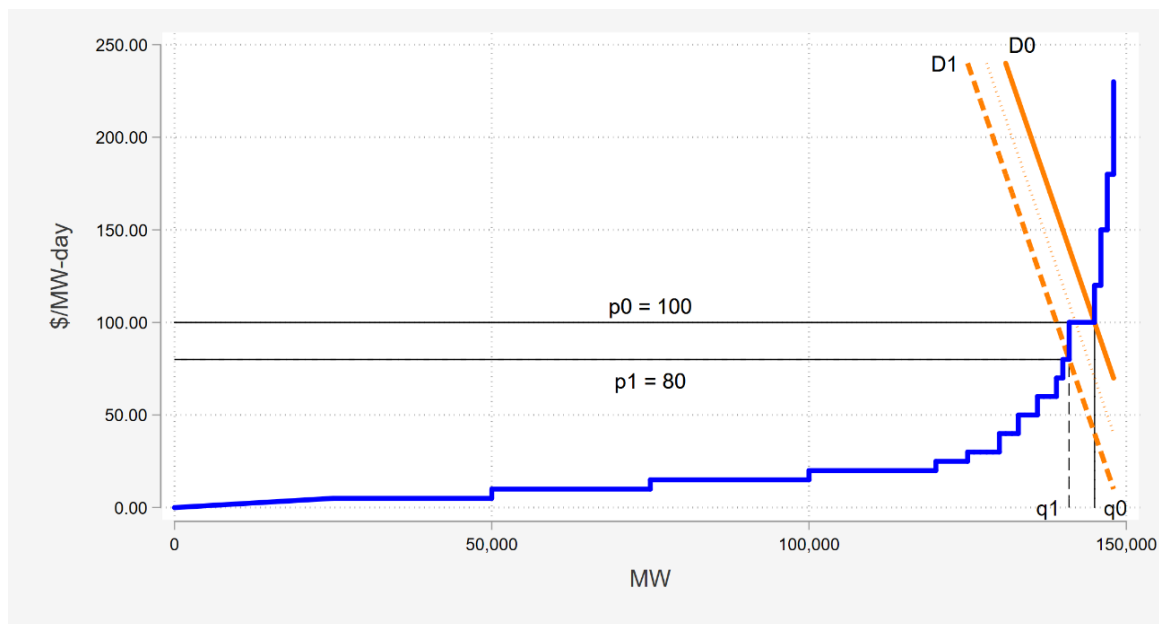
3 VALUATION OF PEAK SHAVING ADJUSTMENTS

3.1 THE ECONOMIC THEORY OF CAPACITY PRICE SUPPRESSION

The resource clearing prices in the PJM BRA are a function of zonal demand and the cost of resources available to meet those demands. The capacity auction clears resources by ascending price until sufficient resources are procured to meet the resource requirements. The result is a supply curve which is flat over a large portion of the resource requirement and then increases sharply. Section 2 demonstrated how PSAs reduce the amount of generation capacity required for a zone. Reducing peak capacity requirements generates value both by avoiding the costs associated with the load being shaved, and potentially by lowering the price for the remaining capacity that still must be procured. This second component is the price suppression effect.

Figure 8 demonstrates the theoretical concept. The demand curve without peak shaving is shown by the orange line D_0 , which results in price of P_0 and a quantity load Q_0 . With peak shaving factored into the peak demand forecast and resource requirement, the demand curve shifts left from D_0 to D_1 which reduces the resource requirement to point Q_1 . This puts downward pressure on prices, in the example reducing the RCP to P_1 . While a PSA will always put downward pressure on price, quantifying that price suppression effect is challenging and subject to significant year to year variation. If the demand curve shift were smaller, or the intersection between supply and demand occurred at a flatter portion of the supply curve, the change in resource clearing price might be close to zero.

Figure 8: Price Suppression Example



The value of peak shaving in the capacity market will vary based on the state of the market (specifically in which region of the supply curve the VRR curve intersects) and the amount of capacity reduced. A peak shaving adjustment guarantees the resource contributor will not need to purchase capacity associated with the reduction in resource requirement, but the value of that reduction depends on the RCP. The price suppression effect is even more uncertain. Because the supply curve is composed of discrete steps, it is possible a PSA does not clear a price block in which case the price suppression effect is negligible as illustrated by the faint dashed line between D0 and D1 in Figure 8. Generally speaking, higher clearing prices result when the VRR curve intersects a steeper portion of the supply function and are associated with larger price suppression effects because the same change in demand will result in a larger change in price.

That said, the substantial uncertainty in the RCP and price suppression effect are problematic because PSAs must commit in advance of the auction which sets the resource clearing price. This means a program administrator must commit to peak shaving activity without knowing what the value of that shaving will be. This makes conducting prospective benefit cost tests of peak shaving programs difficult since the benefit stream is hard to quantify. Program administrators will have to think about how to set program incentive levels without knowing exactly what the benefits stream will be for a delivery year, and will have to look at historic clearing prices and base decisions to commit on estimated values. Section 3.2 illustrates the variation in benefit valuation based on RCP changes and estimated price suppression differences from year to year.

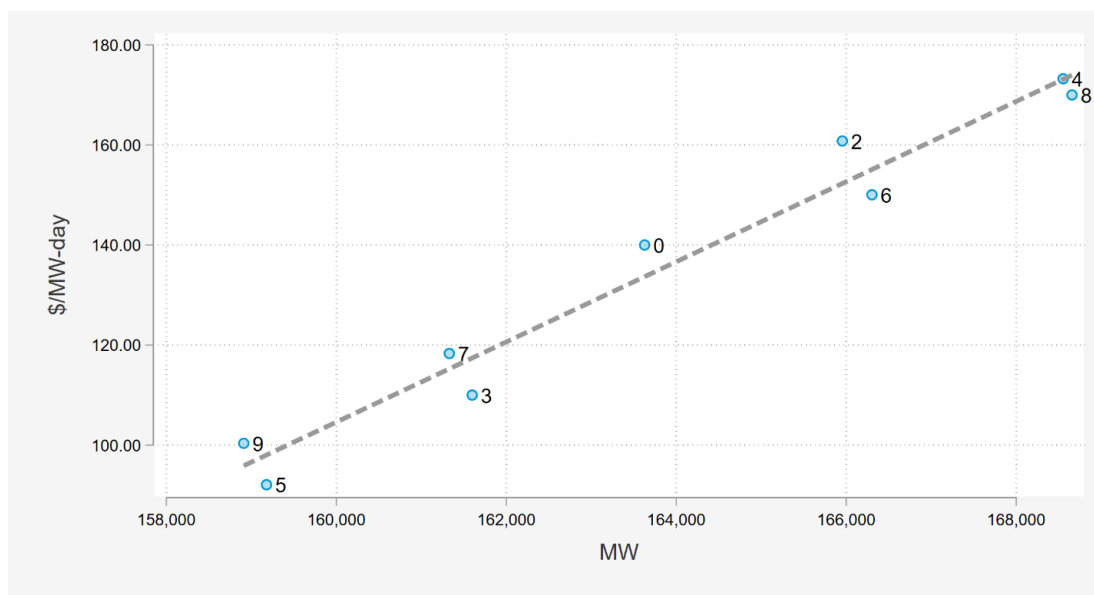
3.2 MODELING OF PJM BRA SENSITIVITY ANALYSES

Peak shaving programs should always reduce the load forecast and as a result, the zonal unforced capacity obligation. A conservative approach to reasonably estimate the PSA benefit is to take the

expected reduction in unforced capacity obligation, and multiply it by the historic average clearing price for the zone. Including estimates of the price suppression effect is more challenging, but by estimating the slope of the supply curve around the RCP and using that predict the clearing price with and without the inclusion of the PSA, we can produce a rough approximation.

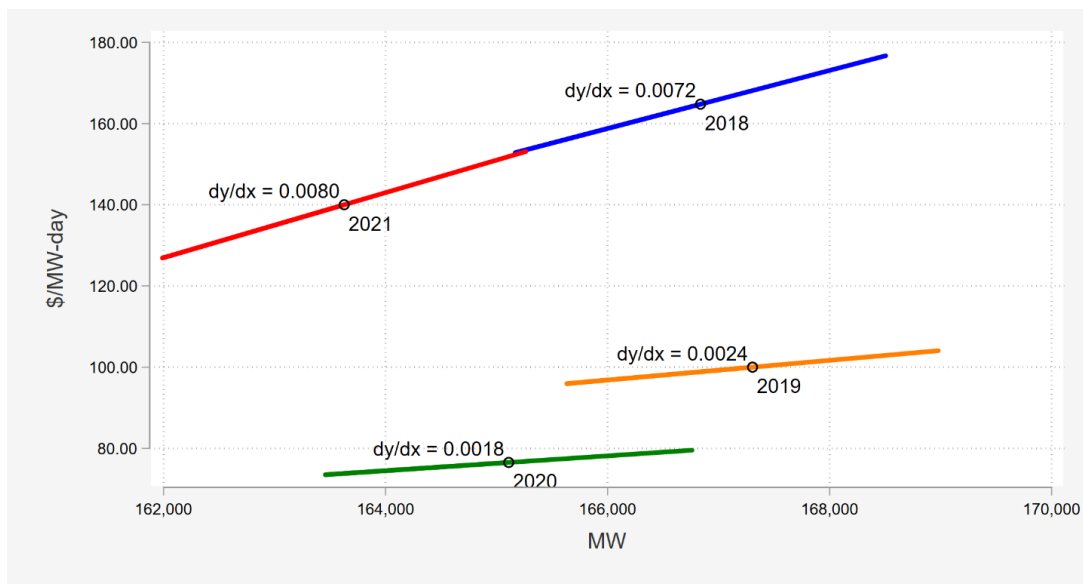
Following each BRA, PJM produces a [sensitivity analysis](#) on the auction results. The PJM BRA sensitivity analyses provide the capacity obligations and RCPs under a number of scenarios in which supply is either added to or removed from the bottom of the supply curve. Adding supply to the bottom of the stack is theoretically similar to removing demand (and vice-versa) so we use these scenarios to generate an approximation of the supply curve slope in the narrow band examined in the sensitives. Each scenario represents a point and a simple regression of price on capacity can estimate the slope of the curve as show in Figure 9. In this case, the slope of the curve in the region of interest is roughly 0.008 which means that a 100 MW peak shaving adjustment would lower the clearing price by roughly 80 cents per MW-day.

Figure 9: RTO Capacity Supply Curve Slope Estimation from BRA Scenario Analysis 2021/2022



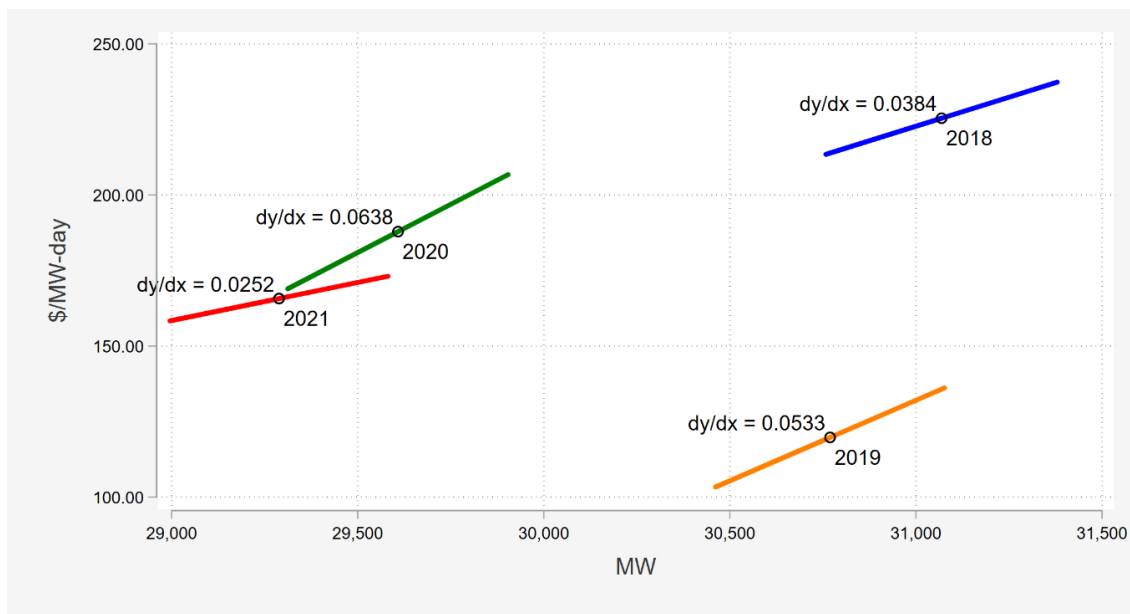
However, the capacity supply curve is not a static entity, it's construction varies from year to year based on a variety of factors – including market rules. It is possible to estimate the general order of magnitude of the slope around the clearing price but there is a significant variation year-to-year. Thus having a several years' worth of BRA scenarios to examine is key in illustrating the uncertainty of the value associated with Peak Shaving Adjustments. Figure 10 shows the estimated slope of the supply curve based on the last four Base Residual Auctions. Based on these calculations the value of the price suppression effect in the 2021/2022 delivery year (labeled 2021) would have been more than four times greater than the 2020/2021 delivery year. The avoided costs associated with the reduced capacity obligation would have also been greater in 2020/2021 due to the higher clearing price.

Figure 10: Supply Curve Slope Approximations from RTO Base Residual Auction Scenarios by Year



The value of a PSA will also vary based on whether or not the supply of the peak shaving resource is located in a constrained Locational Deliverability Area (LDA) or a zone that clears with the rest of the RTO. As shown in Figure 11, the slope estimates in the EMAAC LDA are an order of magnitude larger. This matches intuition as we would expect a peak shaving resource to be more valuable in a constrained area of the system.

Figure 11: Supply Curve Slope Approximations from EMAAC Base Residual Auction Scenarios by Year



To further illustrate the wide range of values for PSAs that may occur from year to year and across LDAs, Table 2 presents the results from a set of sample calculations. ***Each row of the table assumes the***

hypothetical zone has a capacity obligation of 10,000 MW and is offering an PSA that yields a 100 MW reduction in the resource requirement. Using data from the BRA scenario analyses, the capacity obligation is multiplied by the RCP to find the initial cost of generation capacity for the zone. Using the estimated slope, the clearing price after a PSA can be estimated and used to calculate reduced clearing price (-100*slope). The total savings per year is the difference between the annual costs with and without the PSA.

It is composed of two parts. For the first row in Table 2 (RTO for 2021/2022 delivery year), these components are:

- Capacity purchase avoided by lower resource requirement
 - $100 \text{ MW} * \$140/\text{MW-day} * 365 \text{ days} = \$5,110,000$
- Reduced cost for the remaining capacity purchase (price suppression)
 - $9,900 \text{ MW} * (\$140.00 - \$139.20) * 365 \text{ days} = \$2,895,387$

Table 2: Hypothetical PSA Value Calculation

LDA	Delivery Year	Base Clearing Price	Slope	New Clearing Price	Annual Cost w/out PSA	Annual Cost with PSA	PSA Savings
RTO	2021	\$140.00	0.0080	\$139.20	\$511,000,000	\$502,994,613	\$8,005,387
RTO	2020	\$76.53	0.0018	\$76.35	\$279,334,500	\$275,880,705	\$3,453,795
RTO	2019	\$100.00	0.0024	\$99.76	\$365,000,000	\$360,473,759	\$4,526,241
RTO	2018	\$164.77	0.0072	\$164.05	\$601,410,500	\$592,812,465	\$8,598,035
EMAAC	2021	\$165.73	0.0252	\$163.21	\$604,914,500	\$589,745,845	\$15,168,655
EMAAC	2020	\$187.87	0.0638	\$181.49	\$685,725,500	\$655,806,859	\$29,918,641
EMAAC	2019	\$119.77	0.0533	\$114.44	\$437,160,500	\$413,524,181	\$23,636,319
EMAAC	2018	\$225.42	0.0384	\$221.58	\$822,783,000	\$800,665,177	\$22,117,823

It is worth noting that while only the zone contributing the PSA will capture the value associated with the avoided capacity purchase, all zones that clear together will receive the value associated with price suppression. Thus the sponsoring zone is not exclusively capturing the price suppression benefits they create. However, the sponsoring zone will also benefit from any PSAs offered by other entities in their LDA.

A key takeaway from Table 2 is that there is large variation in the value of the same PSA from year to year and across LDAs. In this hypothetical example, values range from \$3.4 million to almost \$30 million annually for an identically sized PSA, depending on year and LDA. While the value is generally higher in

constrained LDAs and when RCPs are higher, anticipating these parameters, particularly over a multi-year period is inherently challenging. As such, program administrators will need to consider the uncertainty in benefits when structuring peak shaving programs and participant incentive levels. Program administrators considering sponsoring PSAs must also decide how reliable they believe estimates of price suppression effects are and decide whether to count on this benefit stream for planning purposes. The more conservative perspective is to only assume the avoided costs associated with a reduced capacity obligation.

In addition to the historic variation discussed above, there are changes to market architecture at PJM that could affect resource clearing prices, and in turn the value of peak shaving. There is currently an Energy Price Formation Task Force¹ at PJM working through issues around the way locational marginal prices are set and other energy market issues. PJM is also undertaking its required periodic review of net cost of new entry (CONE), which is a determinant of the VRR curve. Both of these developments are complex, but the likely outcomes might place additional downward pressure on wholesale capacity prices. At minimum these market changes increase the challenge associated with predicting the future value for PSAs.

3.3 AVOIDED COST OF TRANSMISSION AND DISTRIBUTION CAPACITY

PJM's forward capacity market and the Peak Shaving Adjustment program opportunity deal with generation capacity. The need for transmission and distribution capacity is also driven by peak loads. Peak shaving programs may also be able to avoid or defer capital investment to build or upgrade transmission and distribution networks. The value of peak shaving on the distribution system is inherently location-specific. In 90% of an EDC service territory, there may be no deferral value from peak shaving whatsoever. However, if a large capital project can be deferred or avoided in a specific area of the system, avoided costs can be substantial for program participants on that feeder or substation.

The timing of peaks for individual networks can vary substantially. A mostly residential circuit may peak late into the evening – several hours after the system-wide peak. Program administrators considering a PSA nomination should understand the avoided T&D valuation perspective in their jurisdiction when considering the costs and benefits of peak shaving. It is often useful to work with system planners to understand where load growth related investments are being considered on the system and the extent to which peak shaving activity can potentially defer those capital projects.

¹ <https://www.pjm.com/committees-and-groups/task-forces/epfstf.aspx>

4 CONCLUSIONS AND RECOMMENDATIONS

Conclusion 1: By setting the shaving duration and THI threshold, program administrators can effectively choose how often peak shaving will occur *on average*. Weather conditions will vary from year to year so long-run averages or medians need to be used when selecting program design options. Existing programs also need to take into account agreements with participants and tariff details regarding event timing, frequency, and duration.

Recommendation 1: *Consider the total number of expected curtailment hours per summer. For AC cycling and other residential mass market programs, 20-30 hours per summer is a reasonable goal. There is a tradeoff between number of events and event duration. For example, twelve 2-hour events are the same number of curtailment hours as three 8-hour events ($n=24$ hours). Program designs that seek to shave on fewer days, but for longer durations call for a higher THI threshold. Of course, weather varies across the PJM region so long-run weather should be assessed at the zonal level. Table 3 shows the THI thresholds that correspond to different expected shaving days per summer.*

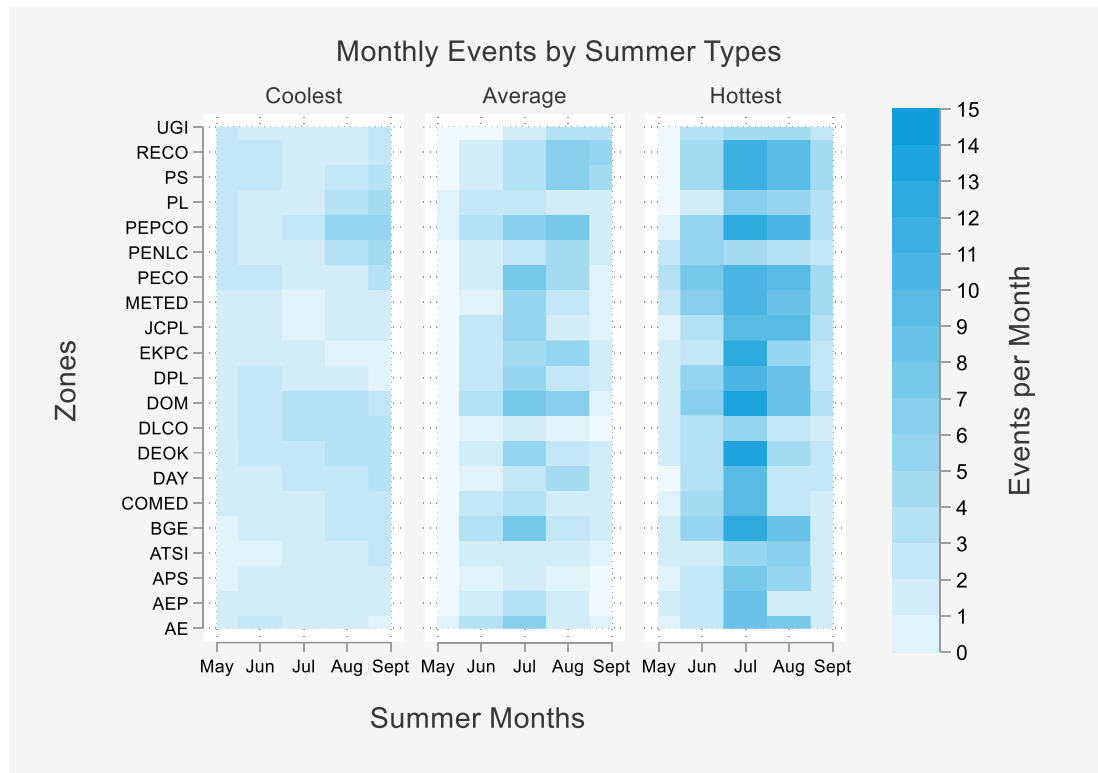
Table 3: THI Thresholds for a Mean of 24 Shaving Hours per Summer

Zone	Twelve 2-Hour Events	Eight 3-Hour Events	Six 4-Hour Events	Four 6-Hour Events
AE	81	82	82.5	83
AEP	79	80	80.5	81
APS	79	79.5	80	80.5
ATSI	78.5	79.5	80	80.5
BGE	81.5	82	82.5	83.5
COMED	80	81	81.5	82
DAY	79.5	80.5	81	81.5
DEOK	80.5	81.5	82	82.5
DLCO	78.5	79	79.5	80.5
DOM	82	82.5	83	83.5
DPL	81	81.5	82	82.5
EKPC	81	81.5	82	82.5
JCPL	80.5	81.5	82	82.5
METED	80.5	81.5	81.5	82.5
PECO	81	82	82.5	83
PENLC	78	79	79.5	80
PEPCO	82	83	83.5	84
PL	79	80	80.5	81.5
PS	80.5	81.5	82	83
RECO	80.5	81.5	82	83
UGI	78.5	79.5	80	80.5

Conclusion 2: Not every year is average; there are hot summers and mild summers. Program administrators will need to plan based on long run averages or medians, but be also be mindful of the impact of extreme weather. This is not really a concern for mild summers, but extremely hot summers could strain the relationship with participants.

Recommendation 2: Review the most extreme summer in recent history and make sure the program design characteristics would result in an acceptable number and distribution of events if a similar summer happened. For example, at a threshold of 81 THI for the BGE zone would result in 14 shaving days, on average. However, as illustrated in Figure 12, in an extreme summer, the same THI threshold would have led to 27 events – with 12 of those events occurring in July.

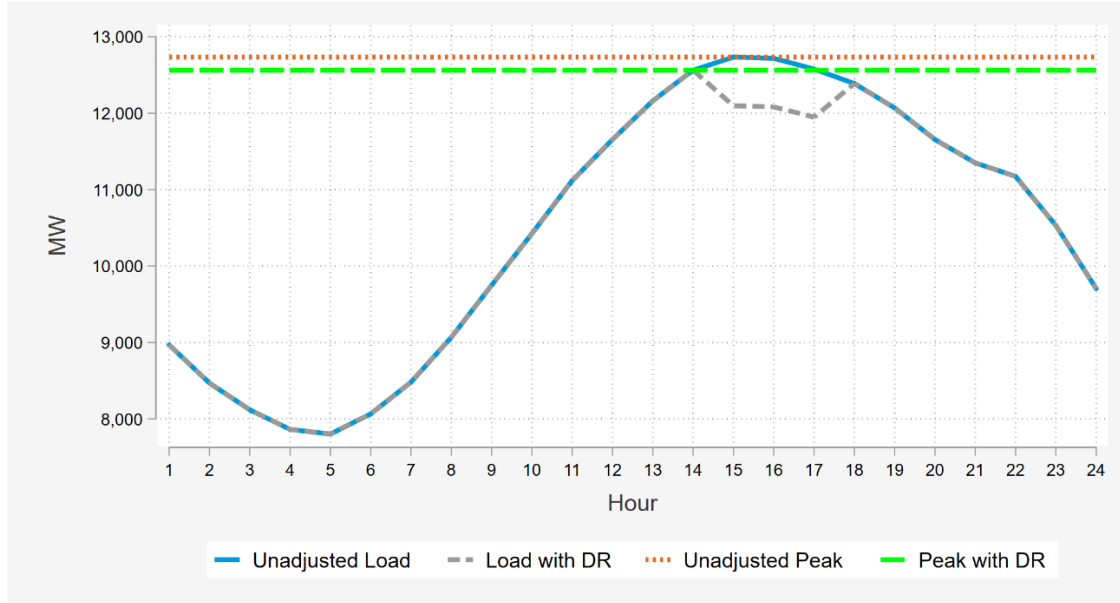
Figure 12: Distribution of Events for Cool, Average, and Hot Summers – 81 THI Threshold



Conclusion 3: The optimal number of shaving hours per day will vary by zone based on the load reduction strategy employed and the amount of shaving being nominated.

Recommendation 3: Use historical zonal load data to assess the degree to which shaving activity will shift peaks to other hours of peak days when the peak shaving program is not active. The larger the peak shaving program is relative to total zonal load, the greater the risk of intra-day shifting. Figure 13 provides an extreme example of the risk associated with shaving durations that are too short. This simulation creates a hypothetical peak shaving of approximately 600 MW and applies it to days above 81 THI on a hot summer (2011). Although the load is reduced by 600 MW during the three shaving hours, the difference in peak load is only 175 MW. This is because the peak shifts to Hour 14 when the peak shaving program is not active.

Figure 13: 600 MW Shaving Program with Three Hour Events – ATSI Zone



If the simulated peak shaving program were 60 MW instead of 600 MW, there would be no intra-day shifting of peak. Hour 15 would still set the peak – even with 60 MW of peak shaving applied to the loads.

Conclusion 4: The value of a PSA program will not be determined until after it is nominated and the RPM clearing price is known for the delivery year. This makes benefit-cost modeling and decisions about customer incentives challenging.

Recommendation 4: *Historical averages of RPM clearing prices can inform an order of magnitude estimate of the value of a peak shaving adjustment, but EDC's must be prepared to handle significant year to year variation. Program administrators should consider the uncertainty in benefits when structuring peak shaving programs and participant incentive levels. That said, a lower value for peak shaving is a net positive for ratepayers because it is associated with lower capacity prices overall. The RPM clearing price drives overall capacity expenditure, so while a higher clearing price makes peak shaving more valuable, it increases annual capacity costs. In other words, the value of the peak shaving adjustment is inversely related to the overall annual capacity cost.*

Conclusion 5: The policy perspective on both capacity price suppression and the ability of peak shaving to avoid/defer transmission and distribution investments varies across PJM states.

Recommendation 5: *Be mindful of state/utility/commission perspectives on which peak shaving benefit streams can be incorporated in the benefit-cost analysis. If the program is not cost-effective without the additional benefits of price suppression, EDCs will need to evaluate how strongly they feel about their inclusion and how reliably they can estimate the associated value. There is no*

question that peak shaving will place downward pressure on the capacity clearing price, but there is a high degree of uncertainty in quantifying the effect. The more conservative perspective is to only assume the avoided costs associated with a reduced capacity obligation.