Energy+Environmental Economics

# CAISO ESDER 4 Stakeholder Process

## Shaped Demand Response ELCC Initial Analysis

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# Agenda

- 10:10 am – 10:15 am: Opening remarks
- 10:15 am – 10:30 am: CA RECAP model & ELCC methodology overview
- 10:30 am – 11:00 am: CAISO, PG&E, and SCE data overview
- 11:00 am – 11:30 am: Initial DR shape day matching algorithm
- 11:30 am – 12:00 pm: Initial Shaped DR ELCC values
- *12:00 pm – 1:00 pm: Lunch*
- 1:00 pm – 1:30 pm: Proposed ELCC allocation methodologies
- 1:30 pm – 3:00 pm: Q&A

# Goals for Today's Discussion

1. **Introduce ELCC as a useful tool for understanding the capacity value of DR programs in meeting system RA needs**
   - ELCC has been used by the CPUC to quantify the capacity value for variable energy resources (wind and solar) as well as battery energy storage
   - We are not currently analyzing local RA
2. **Use actual DR program data to demonstrate the ELCC concept**
3. **Introduce the question of how to allocate ELCC value between individual resources within a portfolio of DR programs**
4. **Solicit feedback on how to more effectively use available data or improve the analysis**

# Initial Takeaways

1. **Using historical DR data, we find that both hourly DR forecasts/bids can vary significantly from monthly NQC ratings**
    - E3 faced challenges using IOU DR data for initial analysis and welcomes collaboration to improve data quality
2. **DR ELCC values can also vary significantly from monthly NQC ratings**
    - For the purposes of this meeting, we aggregate DR program results from sub-LAP level up to LCA to compare against CPUC-published monthly NQCs

# ELCC Methodology & RECAP Model Overview

# Qualifying Capacity (QC) Calculation for DR Today

- **NQC values for DR today is determined via CPUC's Load Impact Protocols (LIP) regression methodologies**
  - QC value is based on **average expected (*ex ante*) load impact** measured during specific measurement hours (1-6 PM in April-October; 4-9 PM otherwise)
  - For QC purposes, use the 1-in-2 weather year LIP data
- **Current QC methodology and DR programs are designed with afternoon peak load as the driver of reliability events**
  - We expect this to change as the system becomes more decarbonized

# Why Use ELCC?

- **Effective Load Carrying Capability (ELCC) represents the equivalent "perfect" capacity that a resource provides in meeting the target reliability metric (e.g., 0.1 day/year LOLE)**
  - ELCC can also be thought of as the incremental load that can be met throughout the year while maintaining the same target reliability metric
- **ELCC captures hourly and seasonal production variability to measure effects of low-probability "tail events" that drive the reliability planning**
- **The CPUC Resource Adequacy Proceeding uses ELCC to quantify the capacity values of wind and solar resources[1]**
  - In the 2019-2020 IRP cycle, additional analysis on the ELCC of battery storage

[1] https://www.cpuc.ca.gov/General.aspx?id=6442451972

# Calculating Resource ELCCs

+ **Effective load carrying capability (ELCC) is a probabilistic measure of a resource's contribution to system resource adequacy requirements**

+ **Marginal ELCC generally declines as a function of penetration**
  - For the first increment of solar PV installed, production is largely coincident with peak demand
  - As penetration of solar PV increases, "net load peak" shifts toward evening, when solar PV is limited (or zero)

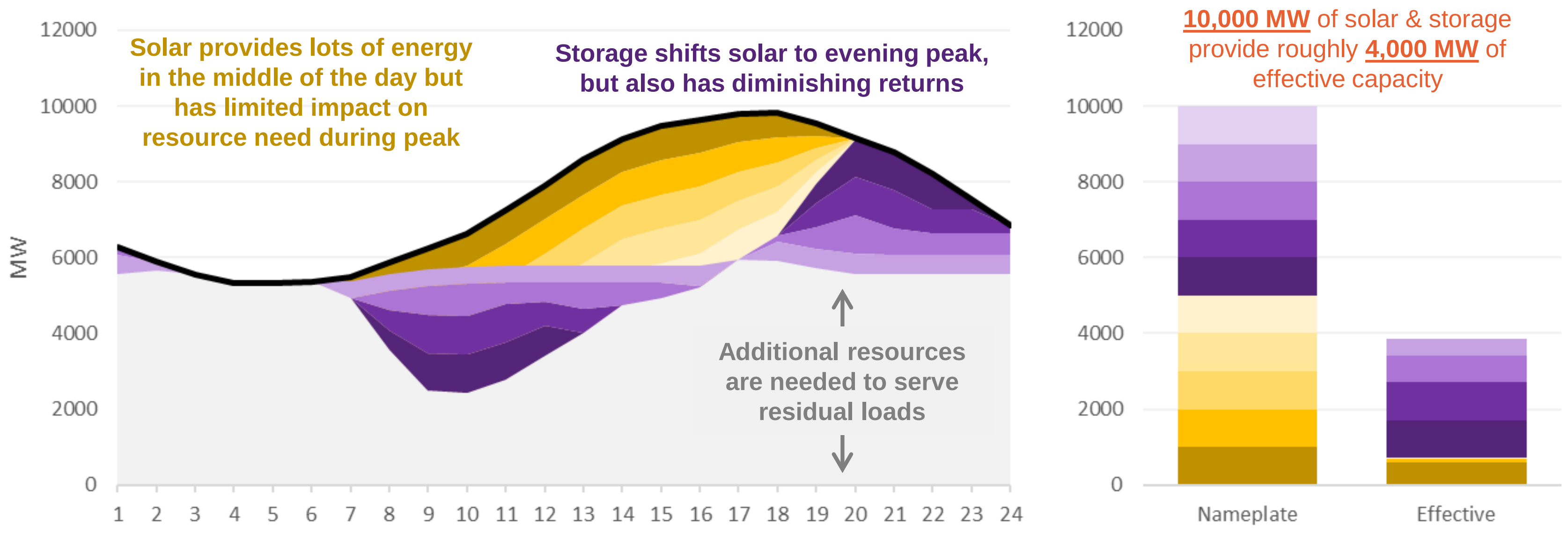



*Figure is illustrative of model dynamics and not a model result*

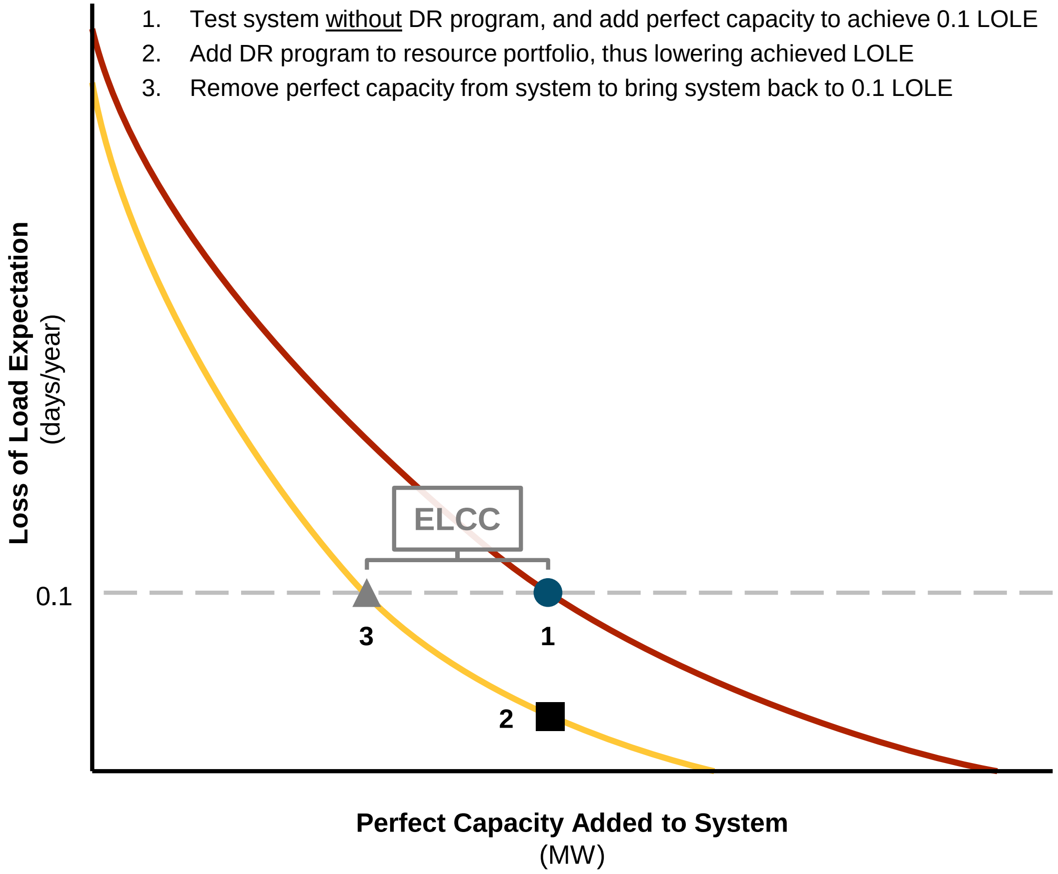
# Context: Reliability Metrics

- **For the purposes of this analysis, we test against a 0.1 days/year Loss of Load Expectation (LOLE) reliability metric**
  - *"Average number of days per year in which unserved energy occurs due to system demand exceeding available generating capacity"*
  - For the purposes of this study a loss-of-load event is considered when **available resources drop below hourly load + 3% operating reserves**
- **The LOLE metric is not tied to a specific weather year but measures the probabilistic reliability of the system across wide range of weather years**
  - Note that the 15% Planning Reserve Margin (PRM) used in California is not tied directly to a reliability metric

# Context: How E3 Calculates ELCC

- **There are two ways to calculate ELCC that are used for different purposes:**
  - **Standalone ELCC**
    Useful for procurement; the marginal ELCC of a DR program
  - **Portfolio ELCC**
    Useful for RA accounting; the aggregate capacity credit (QC) of a portfolio of DR programs
- ***We will come back to the Portfolio ELCC question at the end of the day***

## Illustration of ELCC Calculation Approach

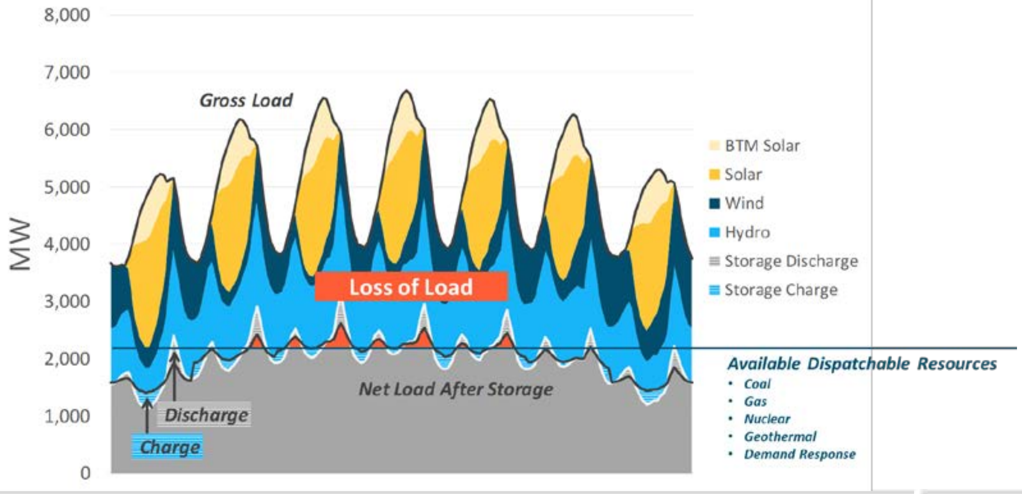


# RECAP Overview

+ **RECAP is a time-sequential, Monte Carlo-based model that evaluates hourly resource availability over thousands of simulated years**
  - In addition to summary statistics, RECAP produces hourly resource availability profiles for all simulated years
  - Time-sequential modeling allows for tracking of DR calls and storage state-of-charge
+ **RECAP calculates system resource adequacy**
+ **RECAP uses historical weather, load, wind, and solar correlations as foundation of Monte Carlo simulation**
  - Additional uncertainty added via **stochastic forced and maintenance outages** for generation and transmission resources

**Map of Recent E3 RECAP Projects**

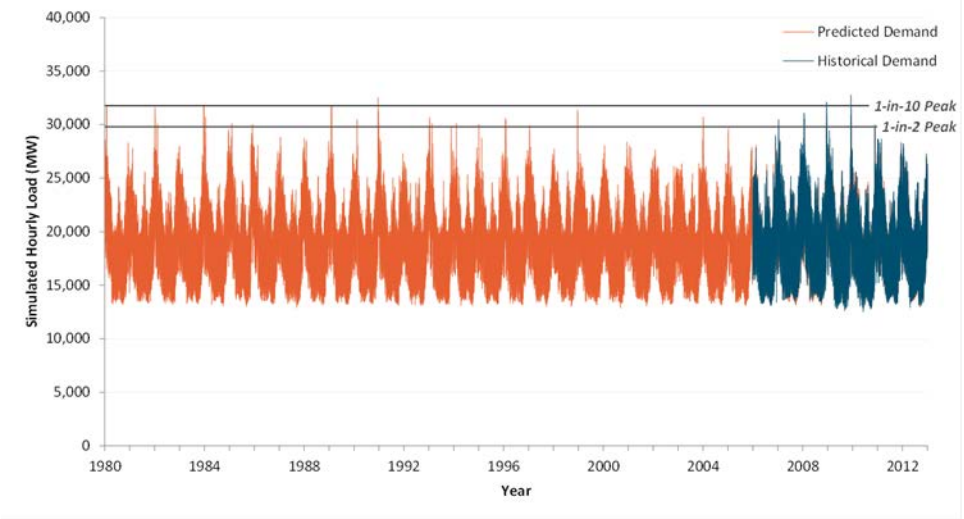

**Example Loss of Load Calculation**



# RECAP Overview

## Developing California Loads & Resource Portfolio

**Example of Neural Network Simulated Load Profile**




- **E3 updated a pre-existing, California-wide RECAP case[1] for this analysis**
  - Updated resource portfolio to reflect current CPUC-jurisdictional resource portfolio (based on 2019-2020 IRP data[2])
- **E3 uses a neural network to develop a longer record of hourly loads that represent wide range of plausible weather conditions**
  - Hourly load data is available for 5-10 years
  - Train neural network on 68 years of historical weather station data across California climate zones
- **To test resource ELCC values, we scale the 1-in-2 gross peak load to historical levels**

[1] Long-Run Resource Adequacy Under Deep Decarbonization Pathways for California
[2] CPUC IRP Events and Materials

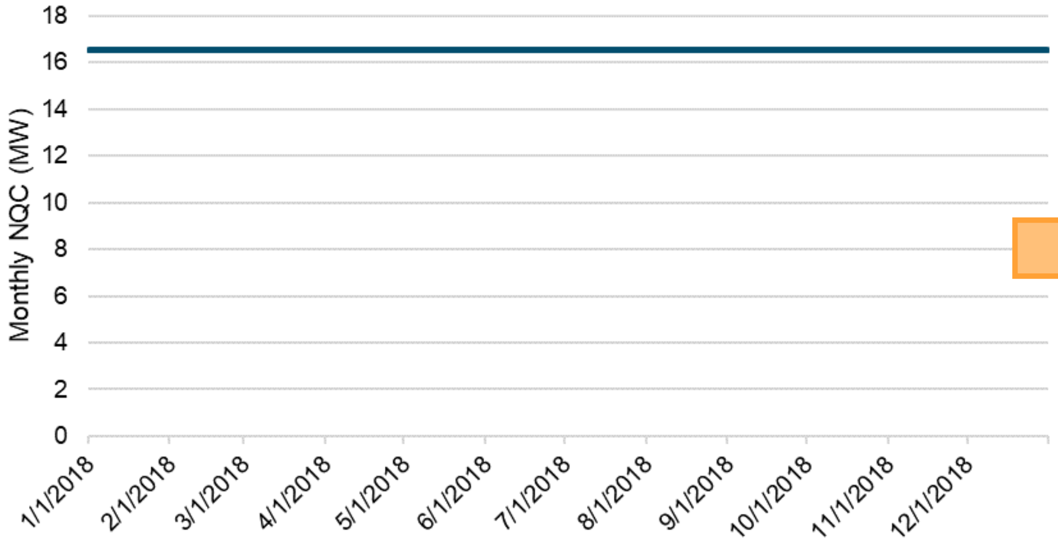
# RECAP Shed DR Functionality

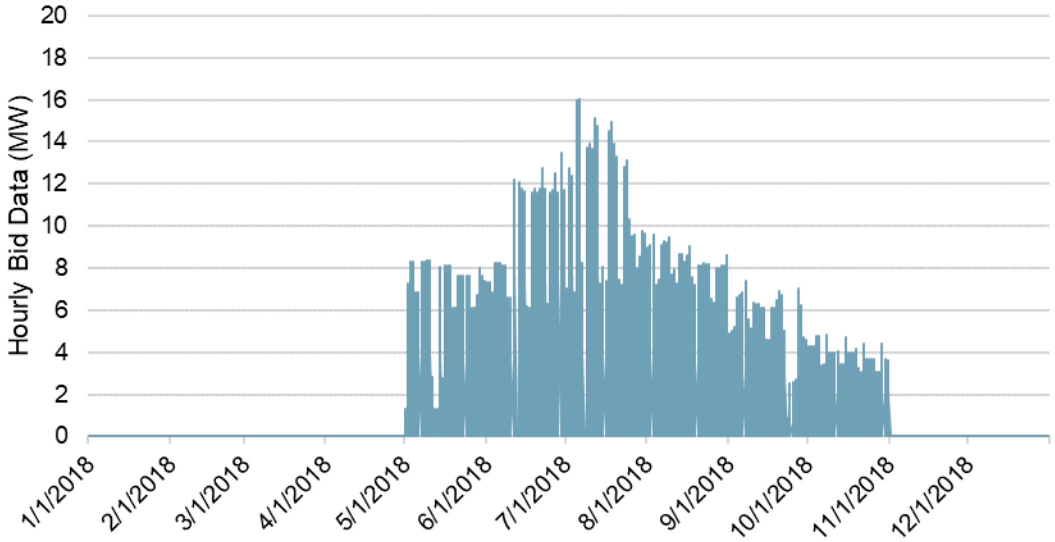
**Existing DR Functionality**

- **Annual Pmax**
- Maximum hours per call
- Maximum calls per month or year

**Shaped DR Functionality**

- **Hourly availability profile**
- Maximum hours per call
- Maximum calls per month or year



# Overview of DR Data

# Overview of Data Request

- **Focused on “event-based” DR programs (as opposed to dynamic pricing)**
- **Not considering DRAM resources**
- **Current data:**

1. CAISO day-ahead market bid data for DR resources:
   - Categorized as PDR and RDRR
2. PG&E DR forecasts* for 2018
   - BIP, CBP, and SAC
3. SCE DR forecasts* for 2017
   - API, BIP, CBP, and SDP

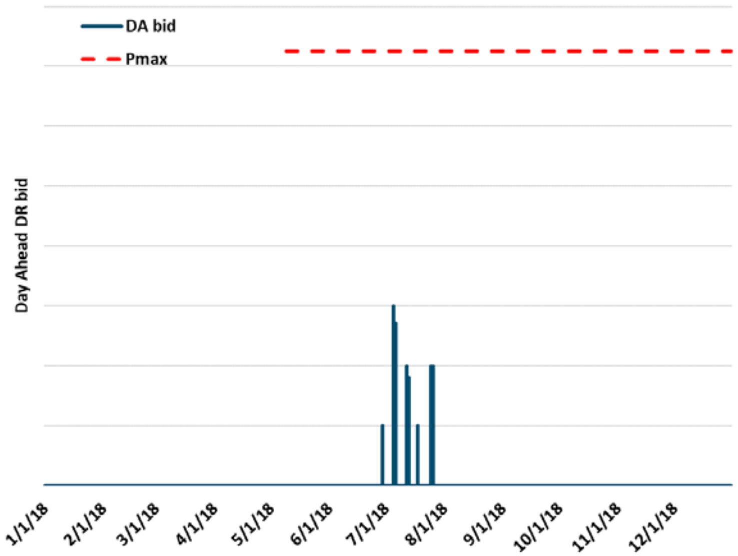
* DR forecasts inform the bids submitted by IOUs to CAISO

# 1. CAISO DR Day-Ahead Bid Data

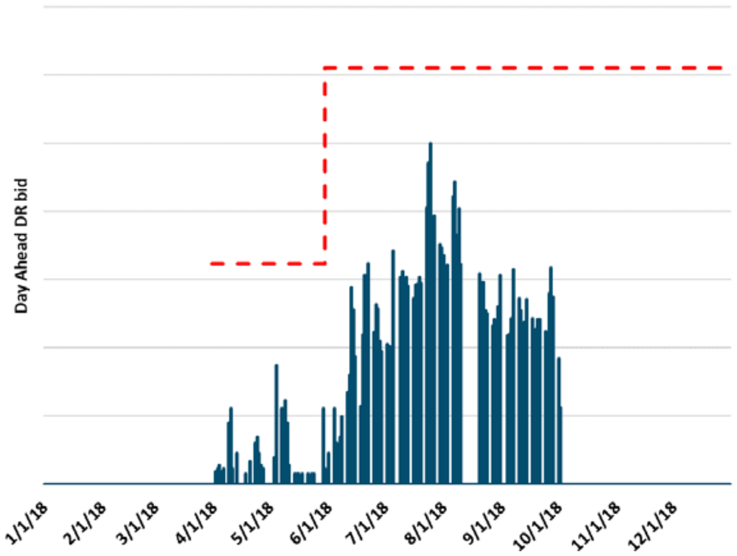
+ **Hourly day-ahead bids for Reliability Demand Response Resources (RDRR) and Proxy Demand Resources (PDR) for PG&E and SCE**
  - Day ahead bids were provided by CAISO for 2017 (partial) and 2018
+ **DR bid data aggregated to utility/DR program/sub-LAP combinations**
  - Multiple bids exist for each utility/DR program/sub-LAP combination
  - Modeled as 26 separate “DR programs” in RECAP

## Characterizing the CAISO DR Bid Data (1/3)

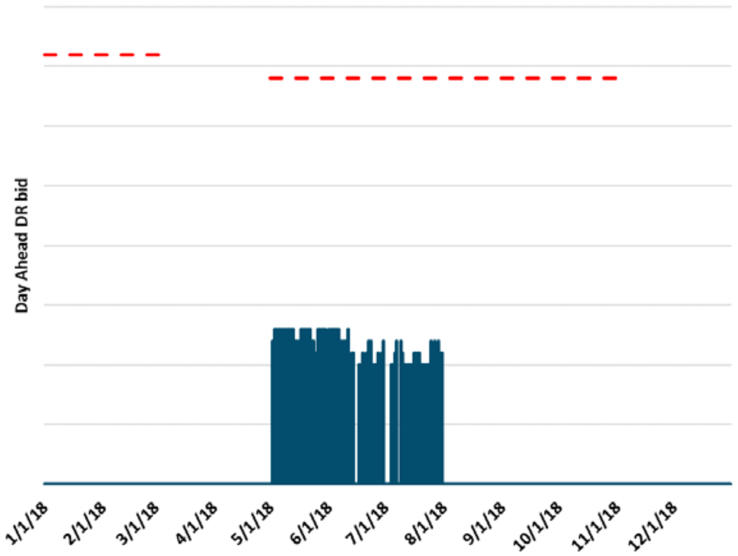
- **The 214 hourly, day-ahead DR bid profiles received can be classified into 8 categories**
- **Profiles in Category 1 were excluded from the analysis, while the rest were included**




Category 1:
- Non-zero DR bids exist on less than 30 days over 2018.
- 41% of all profiles

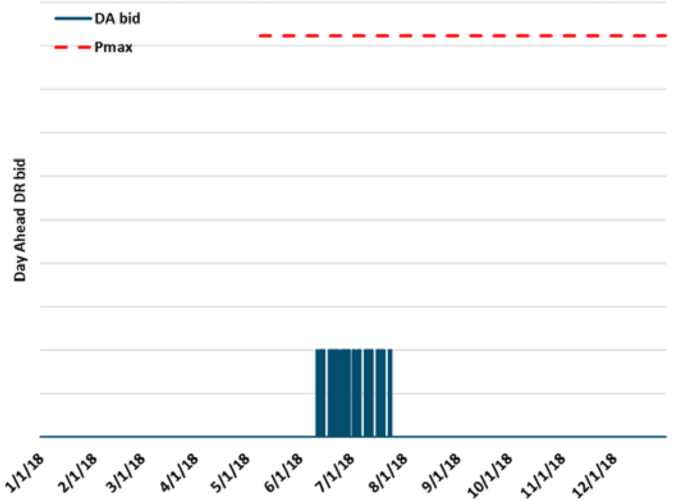


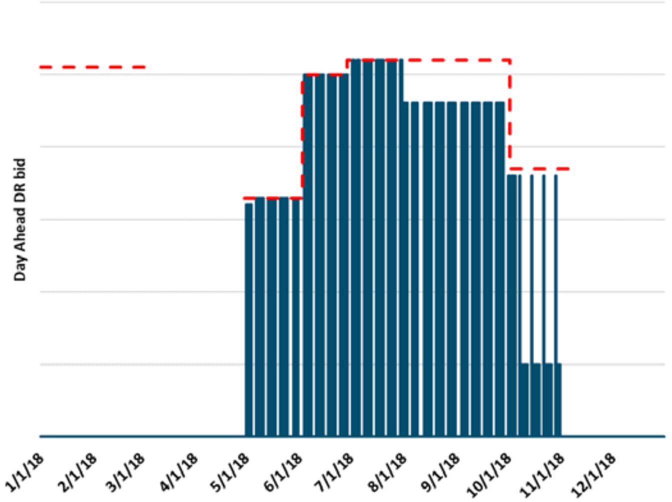

Category 2:
- Profiles that are not “block-like”
- 16% of all profiles

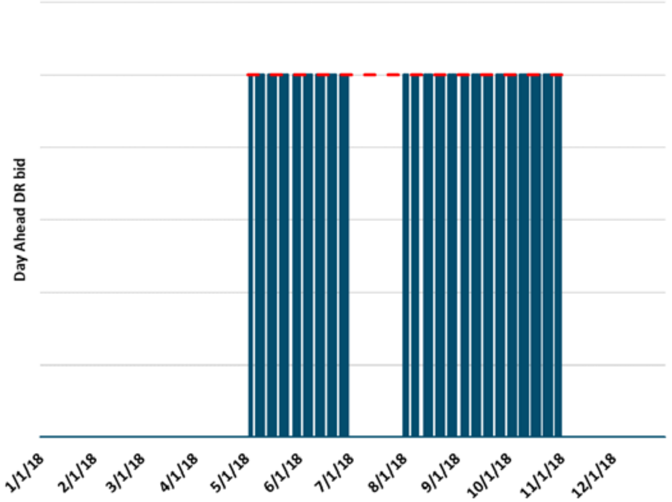



Category 3:
- Profiles that are not “block-like” but significantly less than Pmax all through.
- 2% of all profiles

## Characterizing the CAISO DR Bid Data (2/3)




<u>Category 4:</u>

- Profile has “block-like” characteristic.
- Profile is significantly lower than Pmax all through.
- 2% of all profiles.

<u>Category 5:</u>

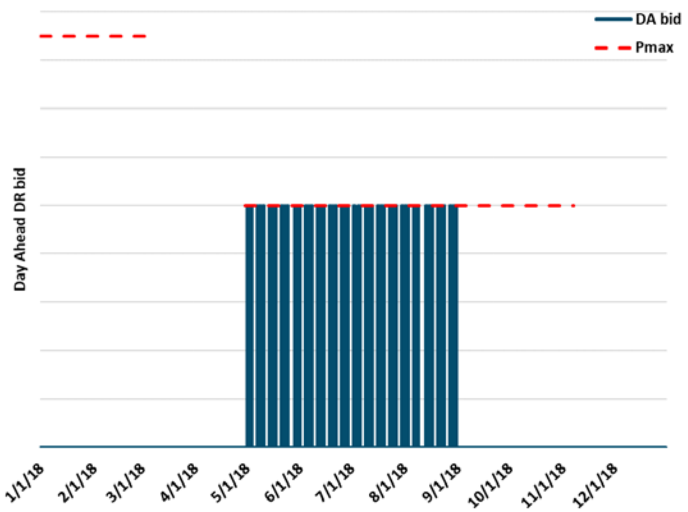
- Profile has “block-like” characteristic.
- Profile is less than Pmax in at least some hours.
- 27% of all profiles.

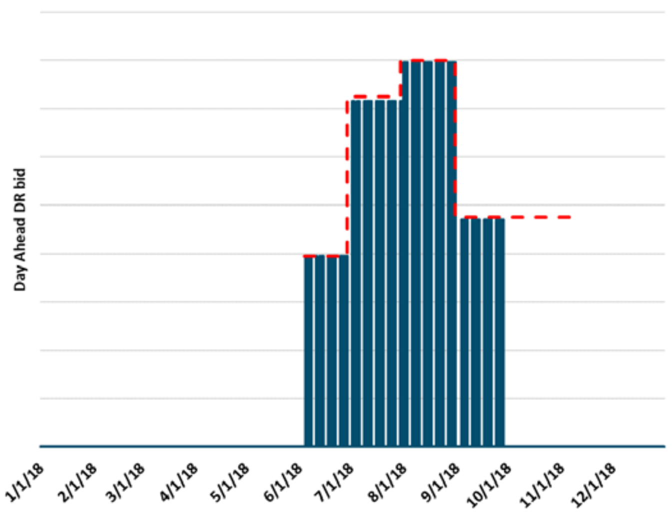
<u>Category 6:</u>

- Profile has “block-like” characteristic.
- Profile matches Pmax for the most part with no DR bid over significant periods of time in the middle.
- 3% of all profiles.

# 1. CAISO DR Day-Ahead Bid Data

## Characterizing the CAISO DR Bid Data (3/3)




Category 7:

- Profile has “block-like” characteristic.
- Profile matches Pmax that stays constant all through the summer.
- 7% of all profiles.

Category 8:

- Profile has “block-like” characteristic.
- Profile matches Pmax that varies across the summer.
- <1% of all profiles.

# 2. PG&E DR Forecast Data

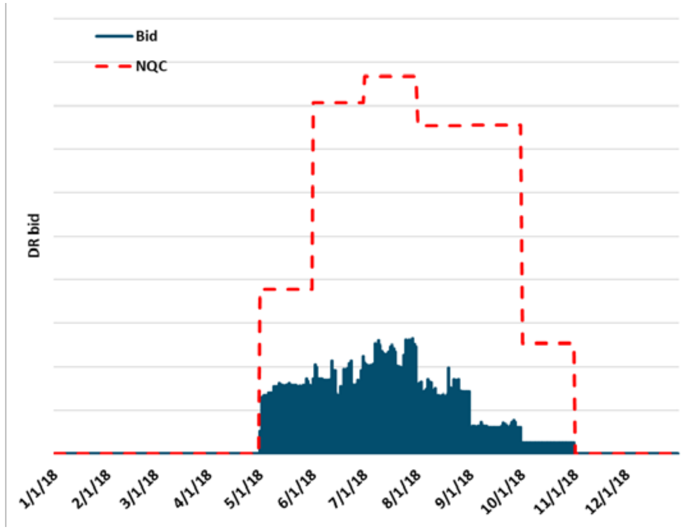
+ **Hourly forecasts for Base Interruptible Program (BIP), Capacity Bidding Program (CBP) and SmartAC (SAC) Program**
  - Hourly forecasts are provided for the year 2018
  - CBP and SAC are part of PDR while BIP is part of RDRR
  - CBP and SAC combined match well with CAISO PDR data while BIP does not match well with CAISO RDRR data. RTM v/s DA discrepancy is the likely reason.
+ **DR data aggregated to program/LCA level* for comparison to NQCs**
  - Modeled as 23 separate “DR programs” in RECAP

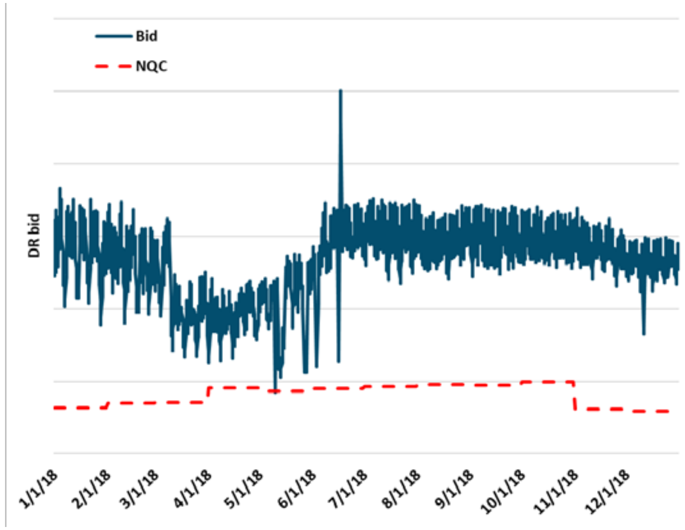
* Comparative statistics for the DR programs can be found in Appendix B

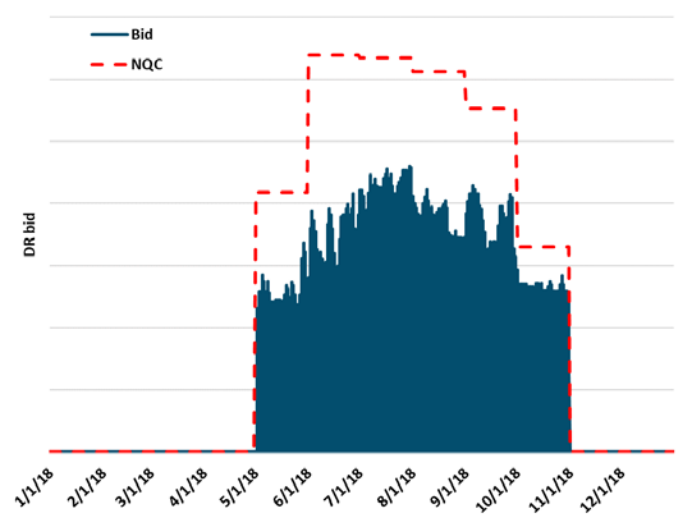
# 2. PG&E DR Forecast Data

## Characterizing the PG&E DR Bid Data (1/2)

+ **The DR bid data received from PG&E can be similarly classified, but now relative to the monthly NQC. Shapes from all these categories were included in the analysis.**




<u>Category 1:</u>

- Profile is not “block-like”.
- Profile is much less than NQC all through.

<u>Category 2:</u>

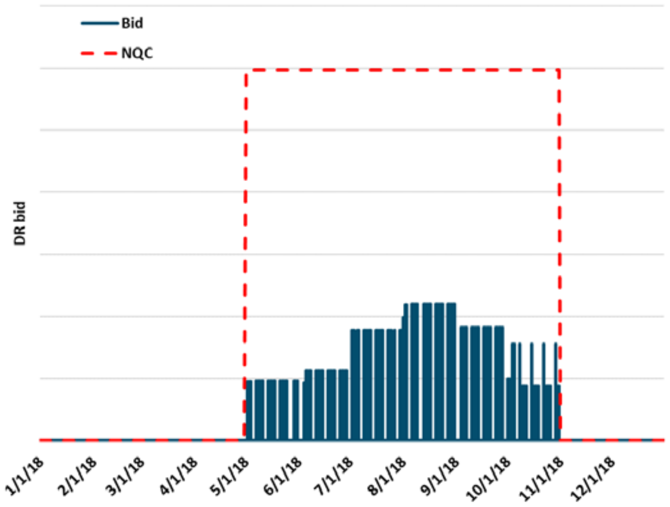
- Profile is not “block-like”.
- Profile is larger than NQC all through.

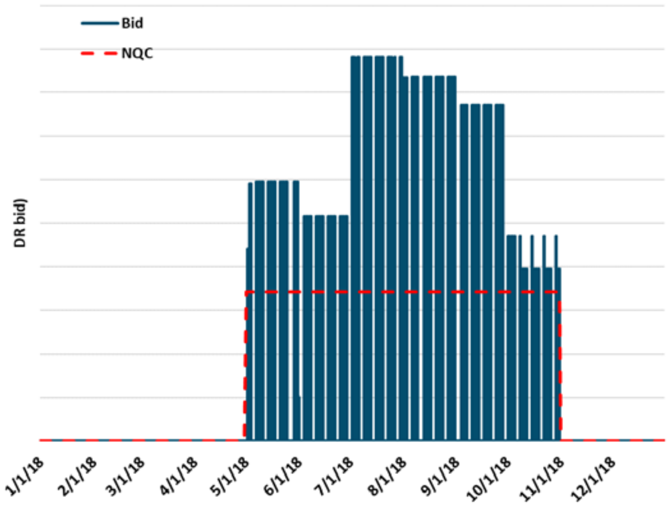
<u>Category 3:</u>

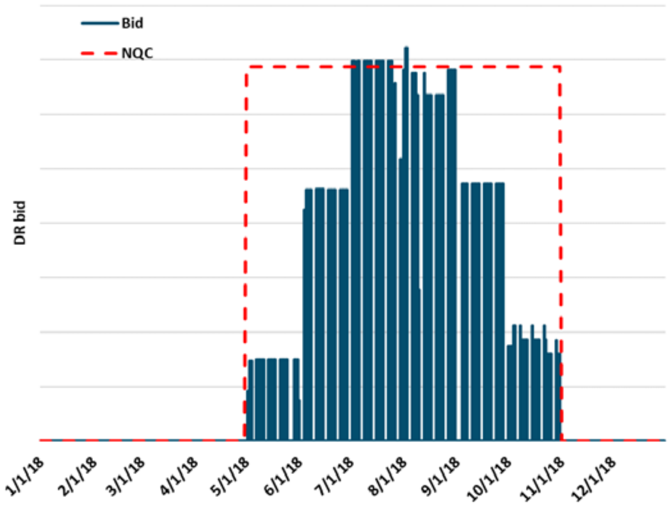
- Profile is not “block-like”.
- Profile is more comparable to NQC relative to categories 1 and 2.

# 2. PG&E DR Forecast Data
## Characterizing the PG&E DR Bid Data (2/2)

+ **Shapes from all these categories were included in the analysis.**



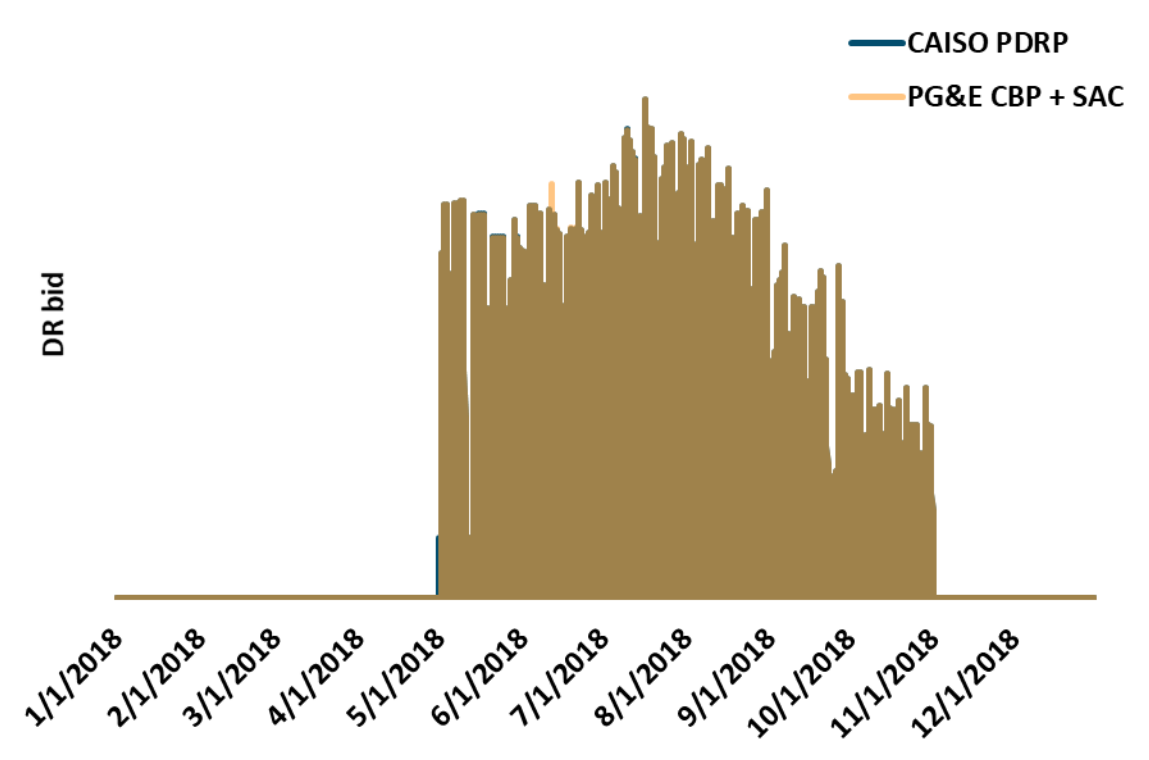

Category 4:
- Profile is “block-like”.
- Profile is significantly less than NQC all through.

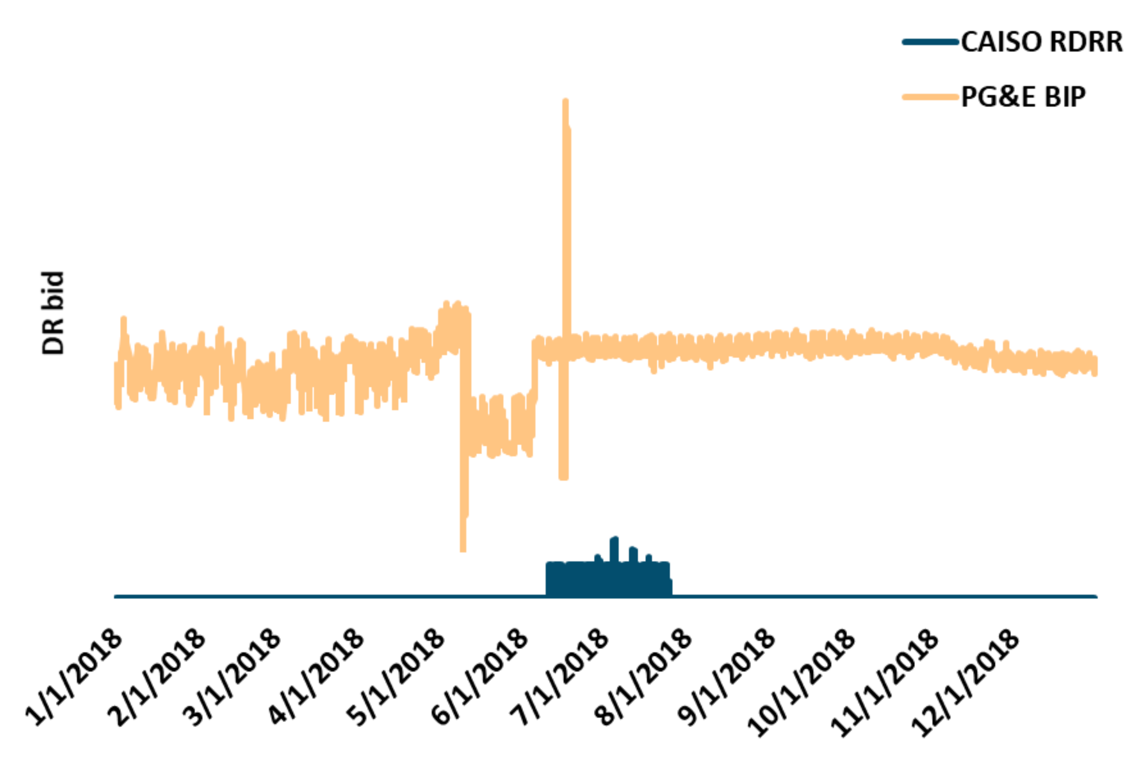
Category 5:
- Profile has “block-like” characteristic.
- Profile is larger than NQC in several hours.

Category 6:
- Profile is “block-like”.
- Somewhere between categories 4 and 5

# 2. PG&E DR Forecast Data

## Example Comparison to CAISO Bid Data




- **Day ahead CAISO PDRP bids match well with sum of PG&E CBP and SAC forecasts as expected.**
- **Likely reason for mismatch is Day ahead CAISO RDRR bids being compared to Real time PG&E BIP forecasts.**

# 3. SCE DR Forecast Data

**+ Hourly forecasts for Agricultural Pumping Interruptible (API) Program, Base Interruptible Program (BIP), Capacity Bidding Program (CBP) and Summer Discount Program (SDP)**

- Hourly forecasts are provided for the year 2017.
- API and BIP forecasts are provided for RTM, CBP for IFM, and SDP for both IFM and RTM*
- SDP forecasts for IFM match well with CAISO's RDRR data.

**+ DR data aggregated to program/LCA level** for comparison to NQCs**

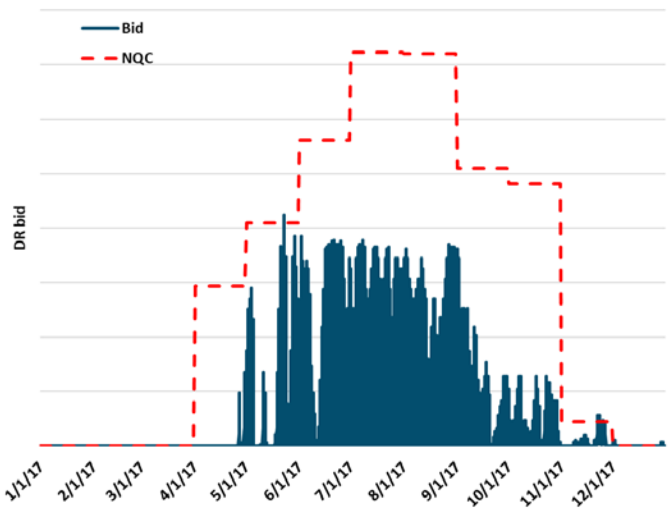
- Modeled as 12 separate "DR resources" in RECAP

* E3 uses union of RTM and IFM for SDP to reconstruct DR availability profile. DR forecasts provided did were not include RTM data if resource had been called in IFM.

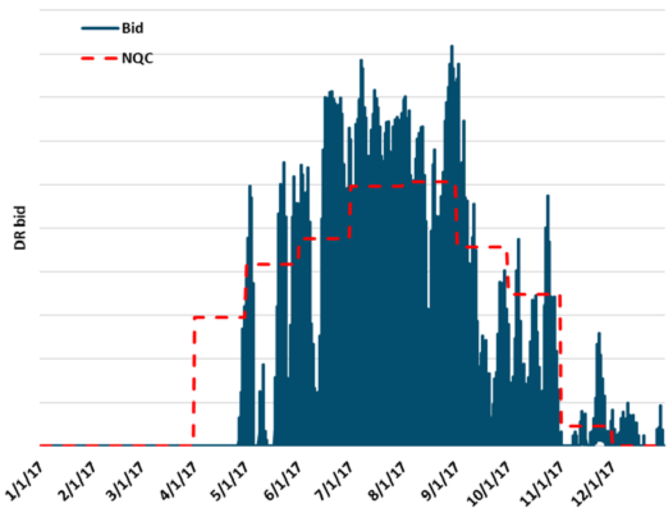
** Comparative statistics for the DR programs can be found in Appendix B

## Characterizing the SCE DR Bid Data (1/2)

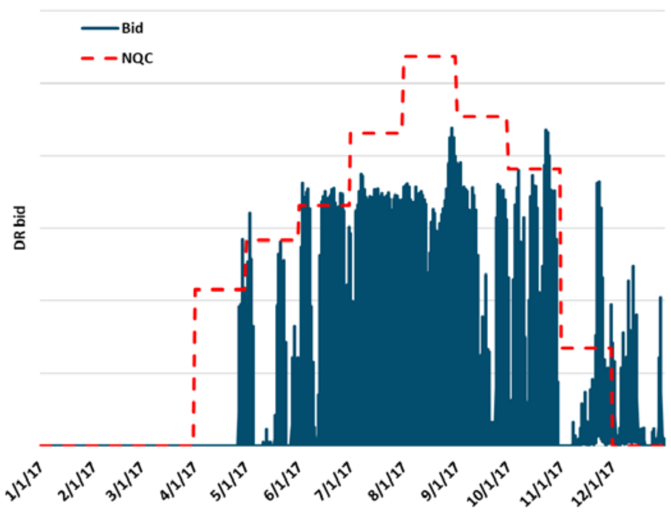
+ **The DR bid data received from SCE can be similarly classified, but now relative to the monthly NQC. Shapes from all these categories were included in the analysis.**




<u>Category 1:</u>
- Profile is not "block-like".
- Profile is less than NQC in most hours.



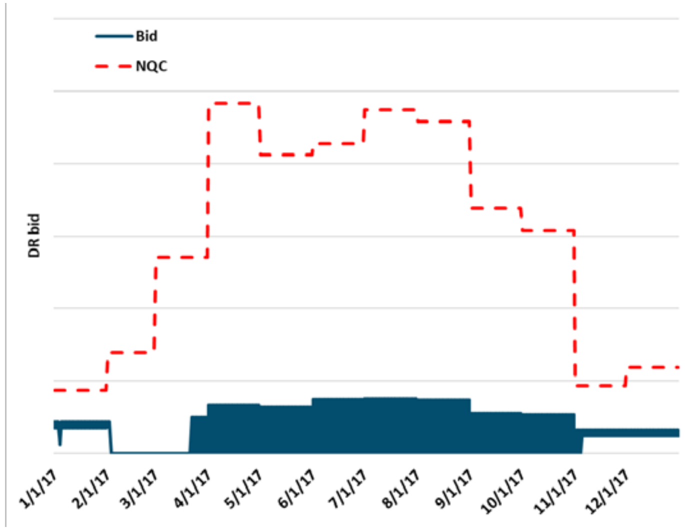

<u>Category 2:</u>
- Profile is not "block-like".
- Profile is larger than NQC In many hours.

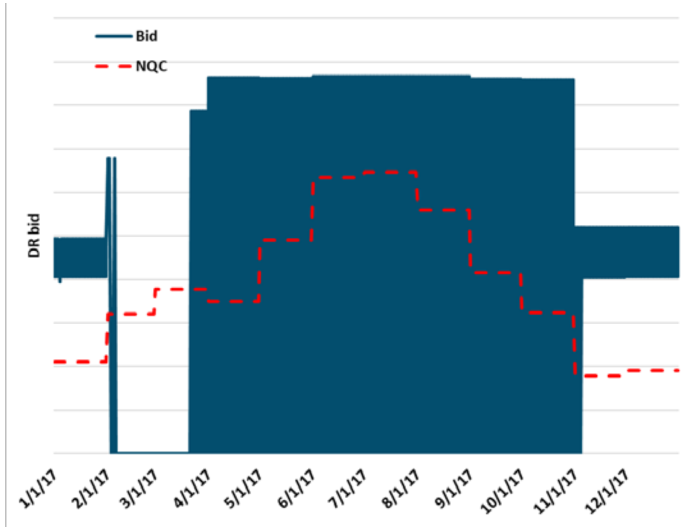


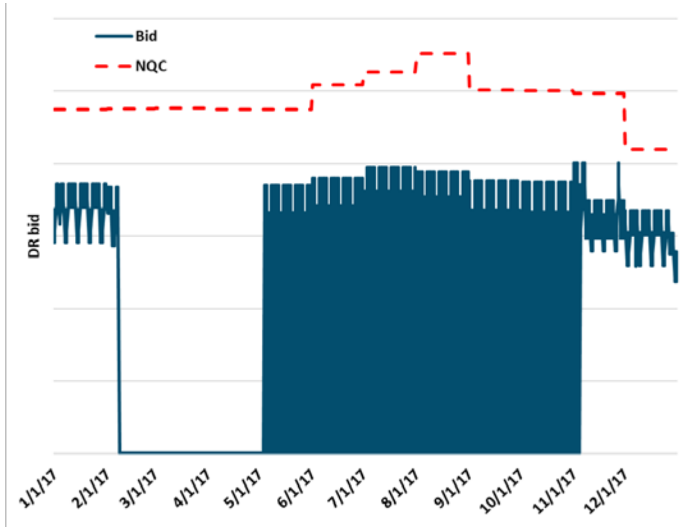

<u>Category 3:</u>
- Profile is not "block-like".
- Somewhere between categories 1 and 2.

## Characterizing the SCE DR Bid Data (2/2)

**+ Shapes from all these categories were included in the analysis.**




Category 4:

- Profile is “block-like”.
- Profile is significantly less than NQC in all summer hours.

Category 5:

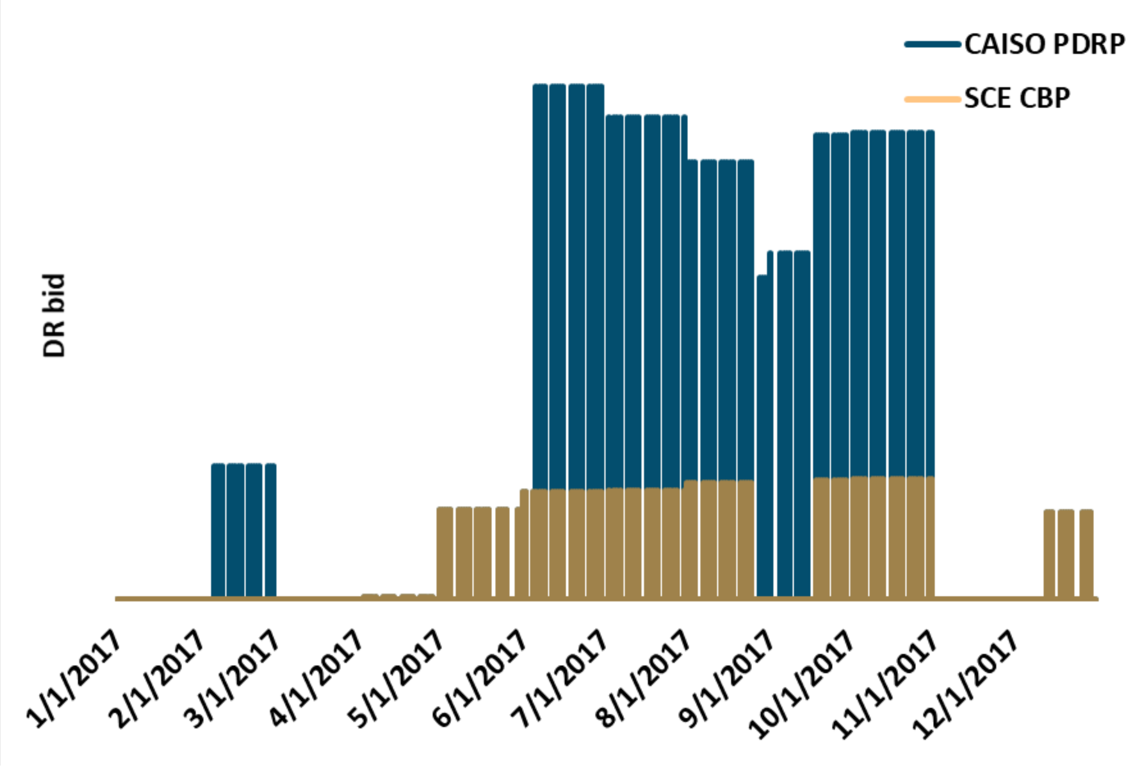
- Profile is “block-like”.
- Profile is larger than NQC In many hours.

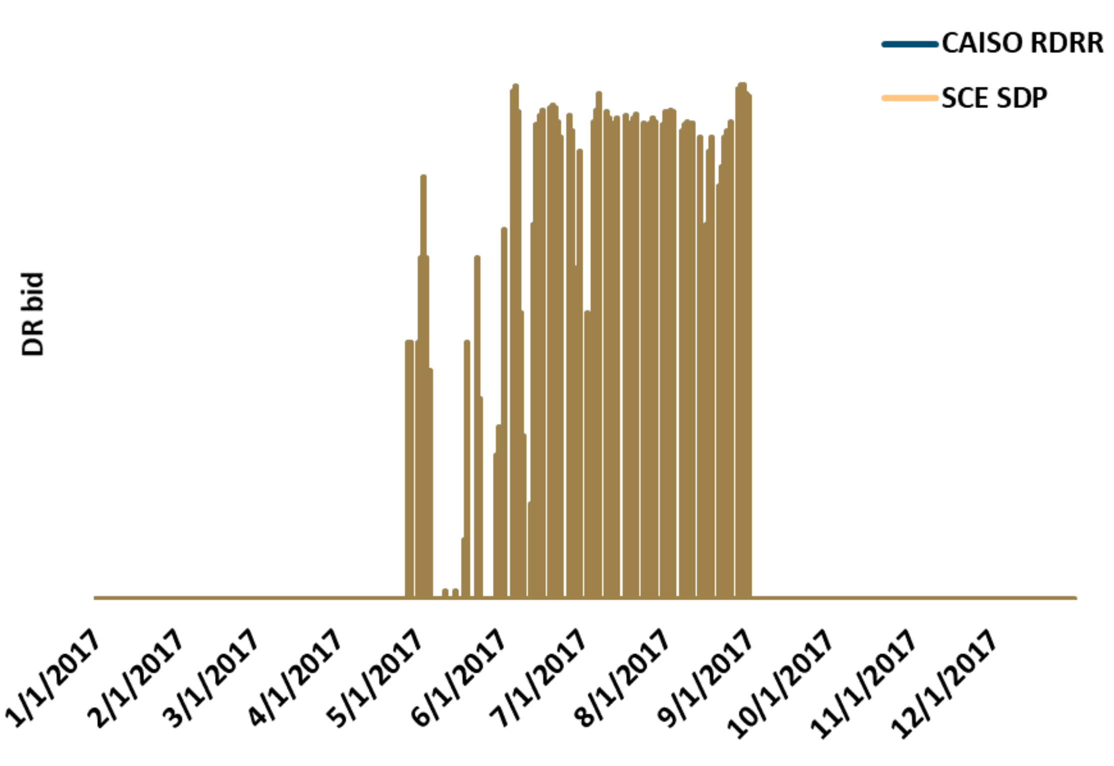
Category 6:

- Profile is “block-like”.
- More comparable to NQC relative to categories 1 and 2.

# 3. SCE DR Forecast Data

## Example Comparison to CAISO Bid Data




+ **Day ahead CAISO PDRP bids do not match well with day ahead SCE CBP forecasts.**
+ ***E3 was not provided with data for a now non-existent program and another confidential program that may at least partially explain the mismatch.***

+ **Day ahead CAISO RDRR bids match well with day ahead SCE SDP forecasts.**
+ **RTM forecasts are provided for API, BIP and SDP.**
+ **E3 uses RTM forecasts for API, BIP and a “union” of RTM and day-ahead for SDP in RECAP.**

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# Extrapolating DR Data

# 1. Temperature-Based Regression for CAISO Data

1. Given day ahead bids for **214 DR resources** (either PDR or RDRR) and one of 20 different sub-LAPs, on an hourly resolution for 2018
2. Aggregate hourly shapes into daily shapes (MWh/day)
3. Initial filtering: **exclude programs with fewer than 30 days of bids** in 2018 (data quality)
4. Run **regression based on daily temperature** to simulate daily shapes from 1950 to 2018
5. Use **day matching algorithm** to go from daily to hourly shapes from 1950-2018
6. Linearly **scale predicted hourly shapes based on actual bid peak** in 2018
7. Aggregate hourly shapes **by type PDR/RDRR and by sub-LAP**
8. Each aggregate shape modeled as a separate **“shaped” DR resource in RECAP**

# Mapping of Sub-LAPs to Climate Zones

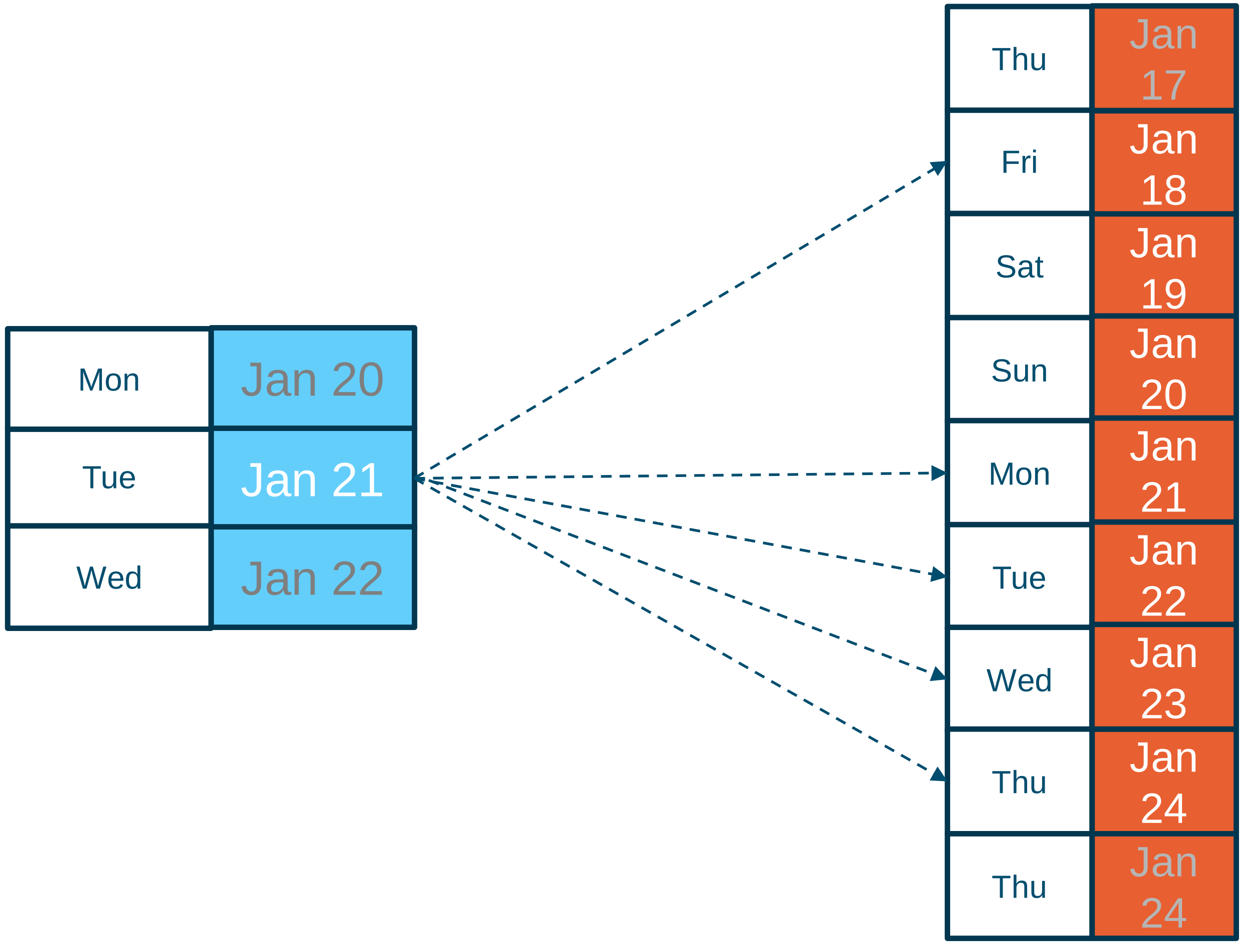
- **E3 uses 68 years of historical daily weather station data to develop regressions for each climate zone**
  - Weather station locations may differ from CZ representative cities due to data issues
- **Geographies of sub-LAPs and climate zones do not align, so E3 selected most appropriate mapping based on available weather station data**
- ***Any suggestions for better mapping of sub-LAPs to climate zones?***

**Mapping Sub-LAPs to Climate Zones**

| Sub-LAP | Climate Zone | Weather Station City |
|---|---|---|
| **PGHB** | 1 | Eureka |
| **PGNC** | 1 | Eureka |
| **PGFG** | 2 | Napa |
| **PGNB** | 2 | Napa |
| **PGCC** | 3 | San Francisco |
| **PGP2** | 3 | San Francisco |
| **PGSF** | 3 | San Francisco |
| **PGSB** | 4 | Moffett Field |
| **PGZP** | 5 | Santa Maria |
| **PGSI** | 12 | Sacramento |
| **PGST** | 12 | Sacramento |
| **PGF1** | 13 | Fresno |
| **PGKN** | 13 | Fresno |
| **SCHD** | 14 | Barstow |

# 2. Day-Matching Algorithm for PG&E and SCE Data

+ **E3 chose to use a day-matching approach for PG&E and SCE DR data**
  - Initially attempted to use regression methodology used for CAISO bid data but found poor regression quality
+ **For an individual DR program and a particular day in a simulated year, pick one day out of +/- 3 calendar days of the same type (workday/holiday) from the year of actuals data.**
+ ***Suggestions for alternative approach?***



# Why the switch from regression to day matching?

- **Regression worked well for AC cycling programs but not others.**
- **PG&E noted that:**
  - CBP forecasts are informed by aggregators' nominated MW
  - BIP forecasts are based on the difference between the reference load and the firm service level. The reference load is informed by load on weather-similar non-event days.
- **SCE data file contained:**
  - A weather station mapping for SDP programs in each sub-LAP but none for API, BIP and CBP programs indicating regression may not be used for the latter set.
- ***Any suggestions?***

# Initial Shaped DR Standalone ELCCs

# Goals of This Section

1. **Provide examples of how DR program standalone ELCC values are calculated using the available DR data**

2. **Compare the standalone ELCC values to the CPUC-published NQCs for corresponding 2017/2018 program years**

   - For CAISO bid data, E3 worked with CAISO to estimate Pmax of each DR bid
   - DR program ELCCs are normalized to NQC or Pmax due to wide range of program sizes

# 1.CAISO Bid Data

## Three Sets of RECAP Runs to Get Us Oriented

a. **Flat DR, Constrained Calls**

- DR programs rated at monthly NQC, constrained to program-defined # of calls
- *We expect ELCC values in this set of results to be close to monthly NQCs*

b. **Shaped DR, Unconstrained Calls**

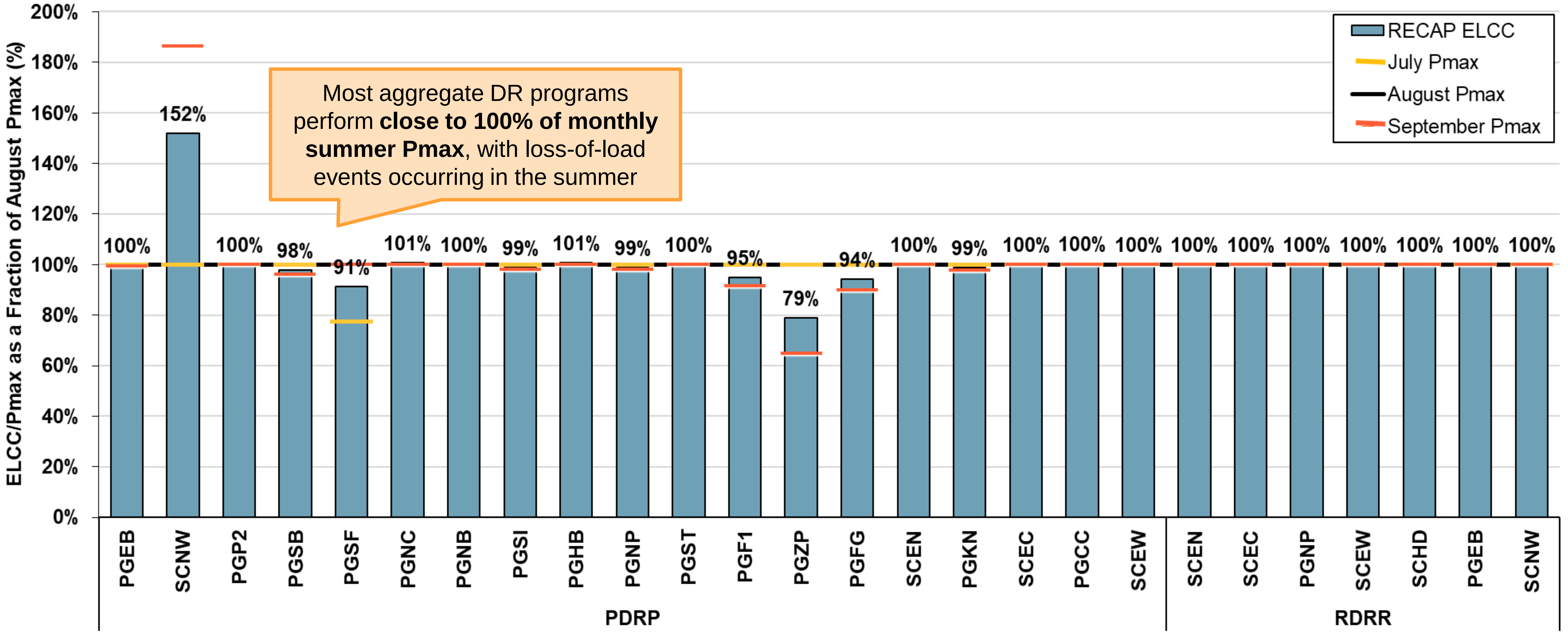
- DR program availability follows hourly profiles, no constraint on # of program calls

c. **Shaped DR, Constrained Calls**

- DR program availability follows hourly profiles, constrained to program-defined # of calls

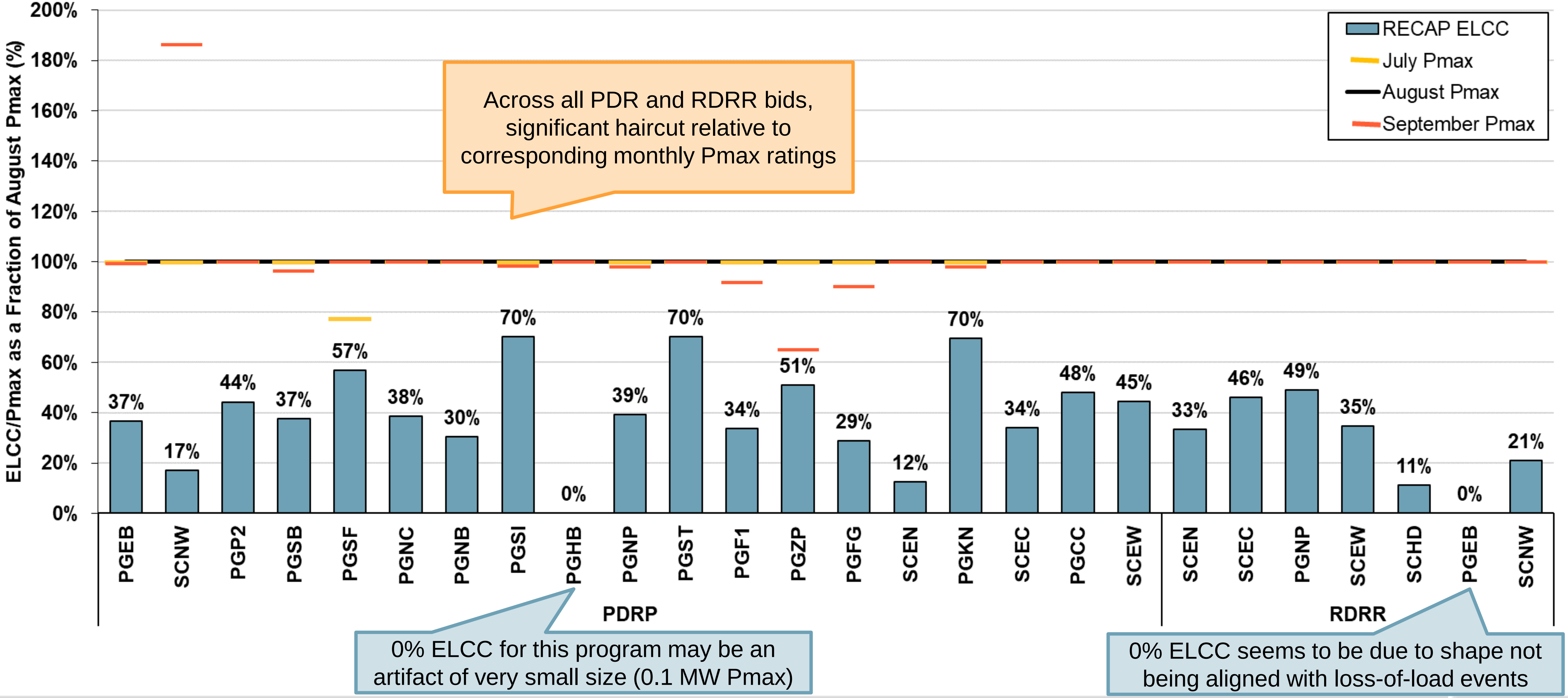
# 1.CAISO Bid Data

## a. Flat DR, Constrained Calls



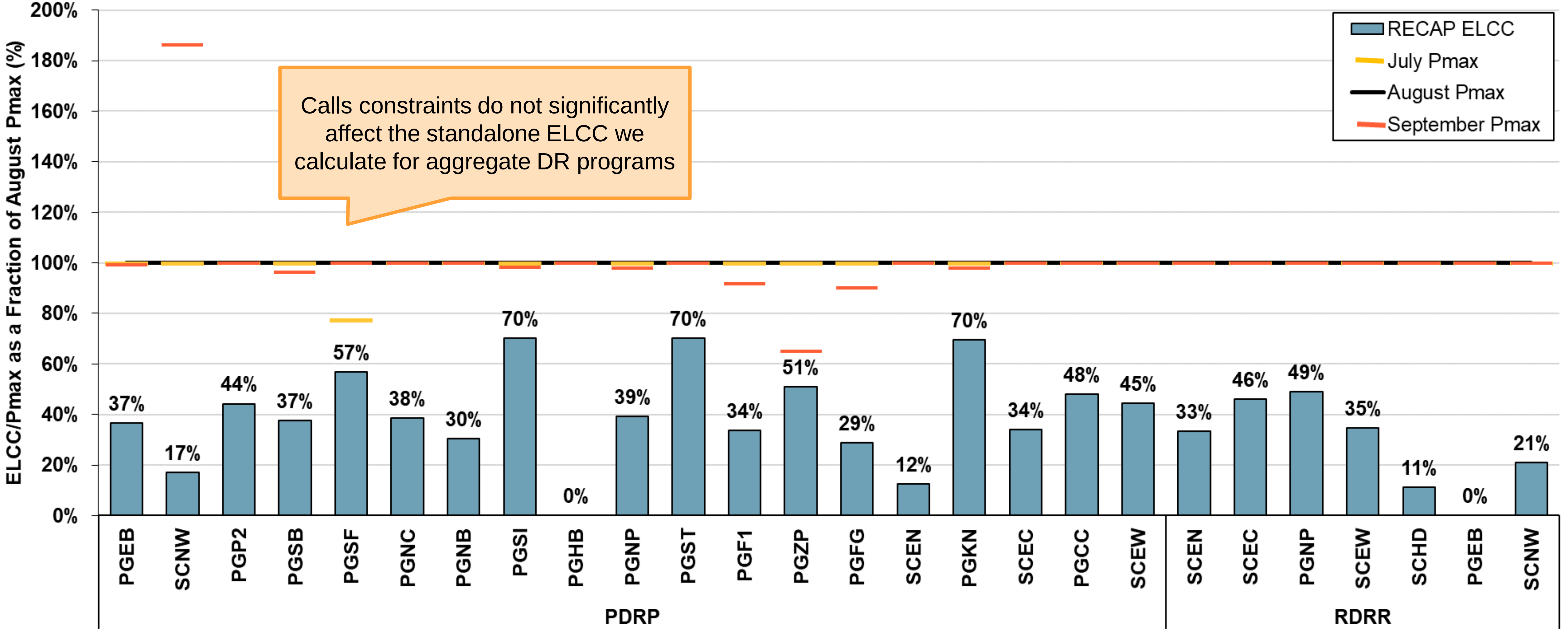
# 1. CAISO Bid Data

## b. Shaped DR, Unconstrained Calls

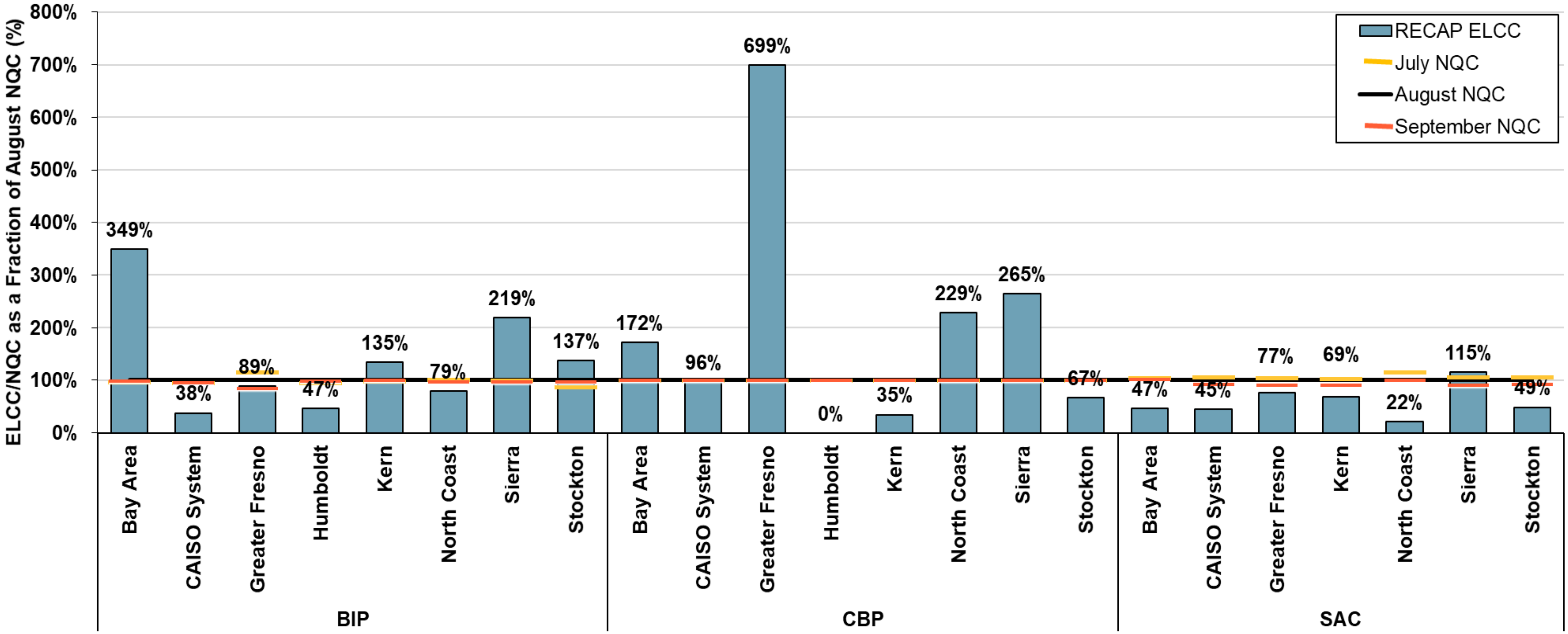


# 1. CAISO Bid Data

## c. Shaped DR, Constrained Calls

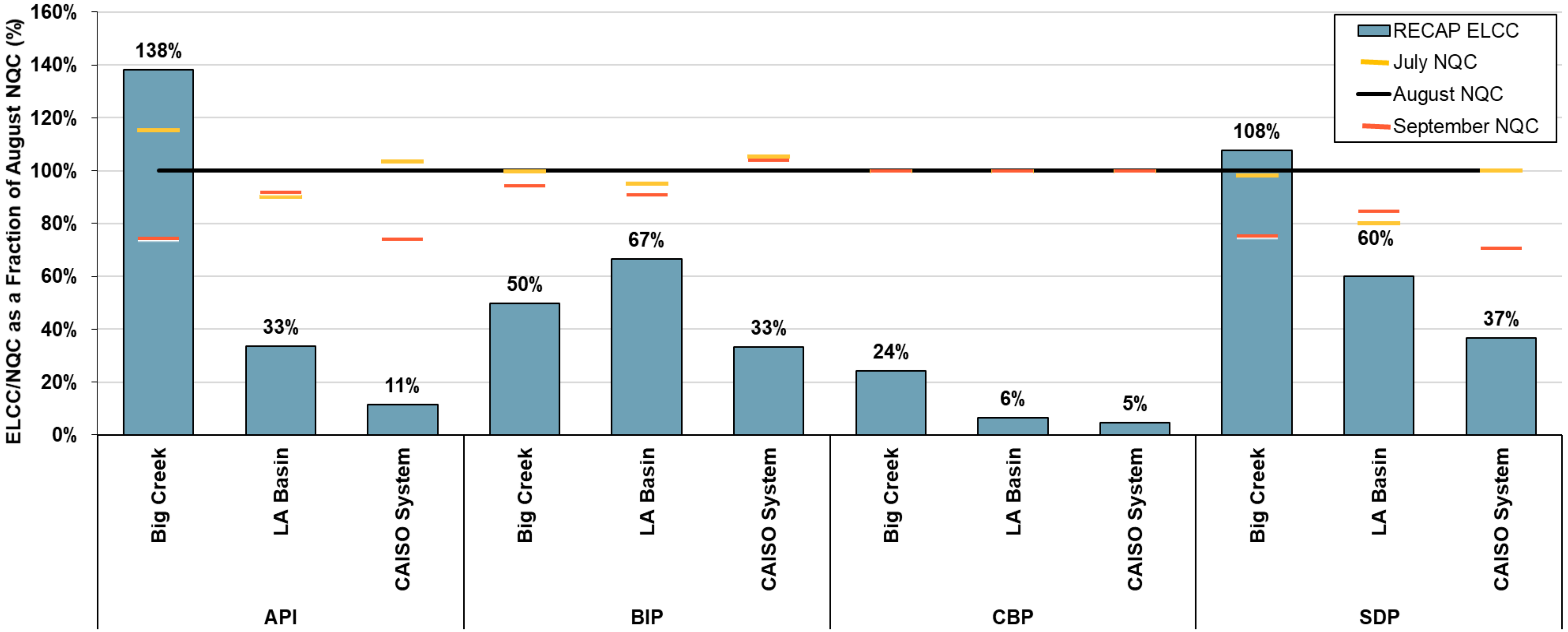


## Shaped DR, Constrained Calls




CAISO System is assumed to be the same as Outside LCA

# 3. SCE DR Programs
## Shaped DR, Constrained Calls




Relative to sum of BIP-15 min and BIP-30 min NQCs

Relative to sum of CBP-Day Ahead and Day Of NQCs

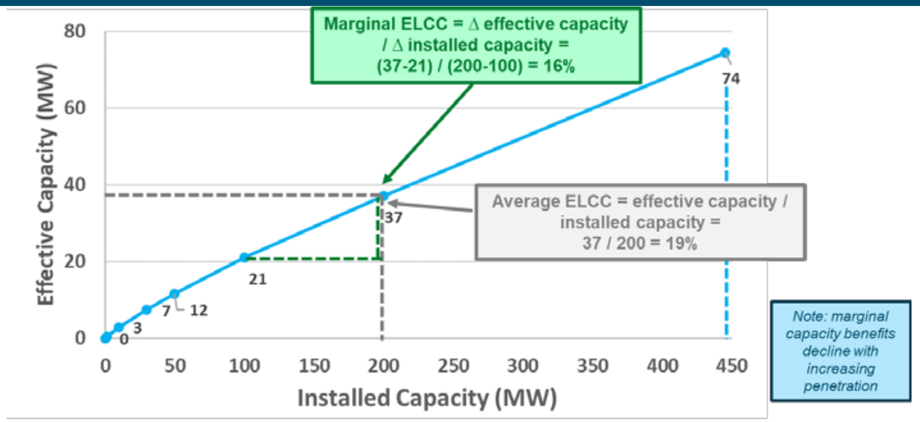
Energy+Environmental Economics

# Portfolio ELCCs & ELCC Allocation

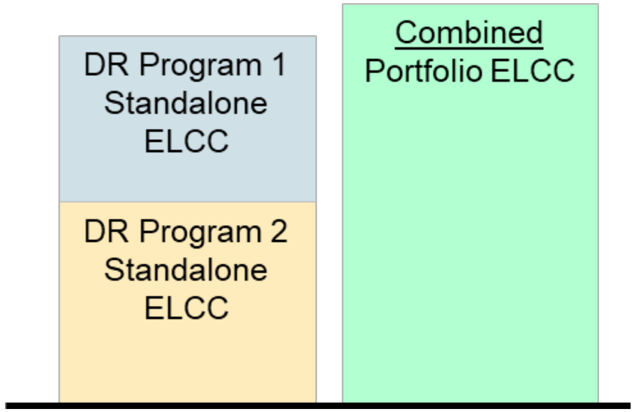
# Different ELCCs for Different Purposes

+ **There are two ways to calculate ELCC that are used for different purposes:**
  - **Standalone ELCC**
    Useful for procurement: the marginal ELCC of a DR program
  - **Portfolio ELCC**
    Useful for RA accounting: the aggregate capacity credit (QC) of a portfolio of DR programs
+ **Due to diversity effect, portfolio ELCC likely differs from the sum of standalone ELCC**
+ ***How do we fairly allocate the contribution of existing resources to the portfolio ELCC?***
  - There are many options, but no standard or rigorous way to do this
  - One consideration: both marginal and portfolio ELCCs can and will change over time

## Illustrative ELCC Relationship with Installed Capacity




## Illustration of Standalone and Portfolio ELCC



# Comparison Standalone ELCCs to Portfolio ELCC

+ **As previously discussed, the sum of standalone ELCCs ≠ portfolio ELCC**
  - We call the discrepancy between these values the diversity effect
+ **For both CAISO and IOU data, we find no/small diversity effect between DR programs**
  - Recall that CAISO bid data and IOU forecast data do not cover the same set of DR programs, so ELCC values are not comparable
+ **We suspect small diversity effect is due to relatively small size of DR programs compared to remaining loss-of-load events in the system**

| CAISO DA Bid Data ELCCs | |
|---|---|
| + Sum of August Pmax: | 632 MW |
| + Sum of standalone ELCCs: | 245 MW |
| + Portfolio ELCC: | 245 MW |

| PG&E + SCE DR Forecast Data ELCCs | |
|---|---|
| + Sum of August NQCs: | 1,451 MW |
| + Sum of standalone ELCCs: | 948 MW |
| + Portfolio ELCC: | 952 MW |

# Next Steps

# Proposed Next Steps

1. **Refine DR data request**
    - Unclear what (if any) effect bidding behavior had on reported DR forecasted
    - Open to feedback from stakeholders on how to extrapolate one year of DR data across many years of historical weather
2. **Refine ELCC results**
    - Potentially calculate monthly ELCCs to compare against monthly NQC values
3. **Run DR ELCC sensitivities**
    - Understand interaction of DR programs with other energy-limited resource (e.g., battery storage)
    - Test how different call constraints or programs definitions may affect calculated ELCC values
4. **Demonstrate various ELCC allocation mechanisms**

# Appendix A: Methodology Details

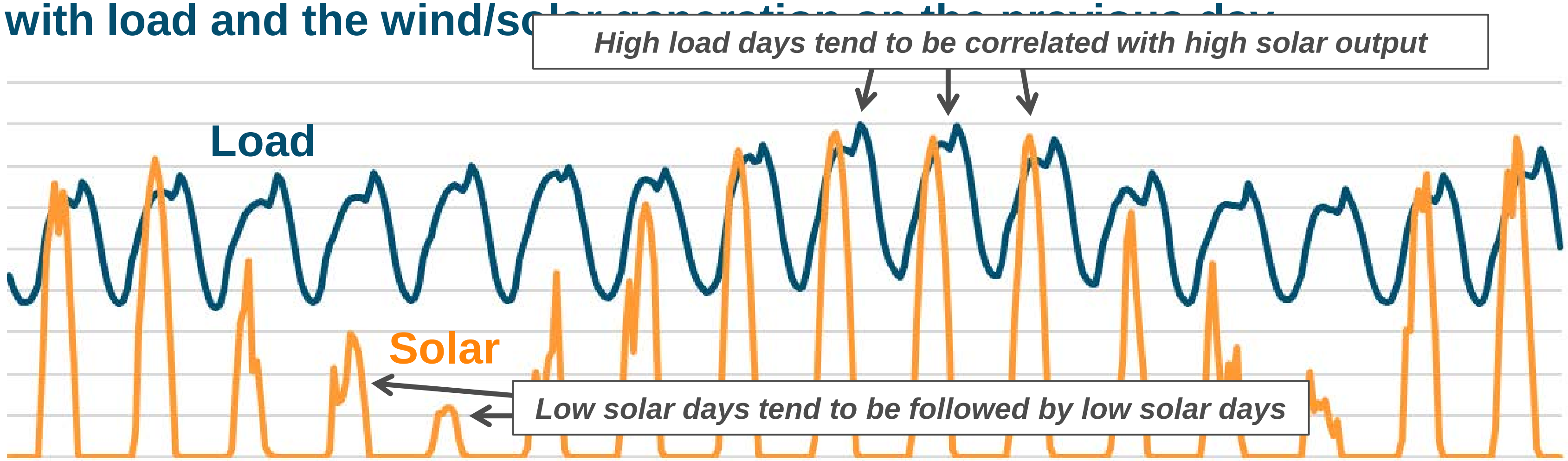
# Review of Reliability Metrics

| Metric Name | Units | Definition |
|---|---|---|
| **Expected Unserved Energy** (EUE) | MWh/year | Average total quantity of unserved energy (MWh) over a year due to system demand exceeding available generating capacity |
| **Loss of Load Probability** (LOLP) | % | Probability of system demand exceeding availability generating capacity during a given time period |
| **Loss of Load Hours** (LOLH) | hours/year | Average number of hours per year with loss of load due to system demand exceeding available generating capacity |
| **Loss of Load Expectation** (LOLE) | days/year | Average number of days per year in which unserved energy occurs due to system demand exceeding available generating capacity |
| **Loss of Load Events** (LOLEV) | events/years | Average number of loss of load events per year, of any duration or magnitude, due to system demand exceeding available generating capacity |
| **Target Planning Reserve Margin** (tPRM) | % 1-in-2 peak load | The planning reserve margin needed to achieve a given reliability metric (e.g., 1-day-in-10-years LOLE) |
| **Effective Load-Carrying Capability** (ELCC) | MW | Effective “perfect” capacity provided by energy-limited resources such as hydro, renewables, storage, and demand response |
| **Residual Capacity Need** | MW | Additional “perfect” capacity needed to achieve a given reliability metric |

# RECAP Methodology

## Capturing Correlations Between Load & Renewables

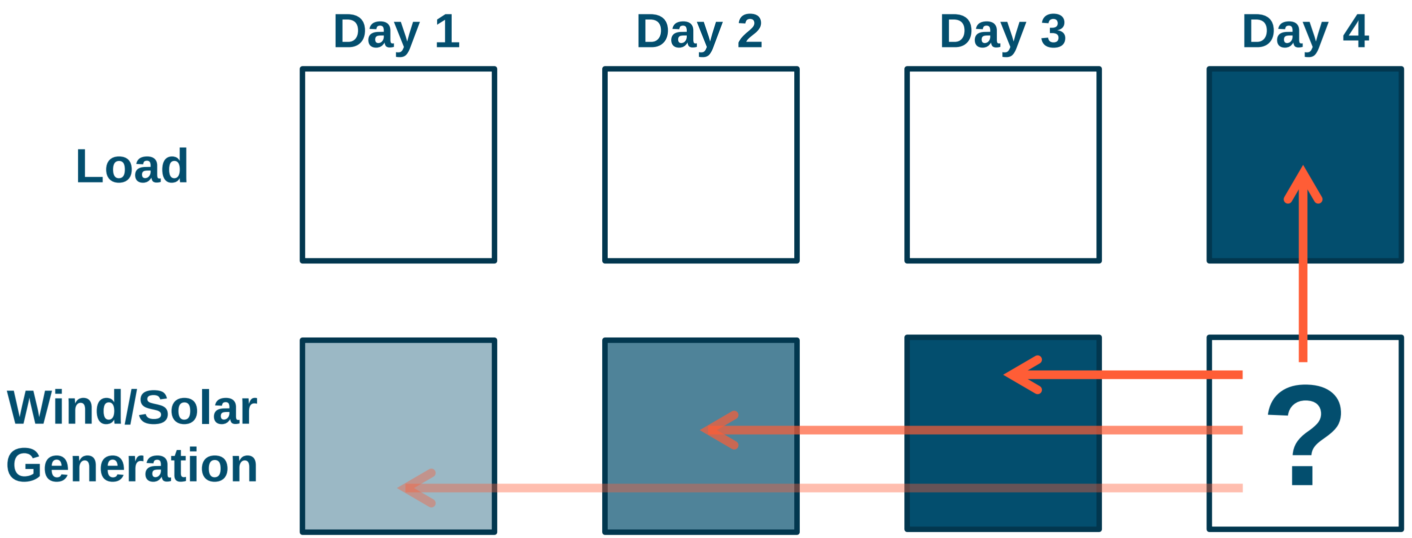
+ **A wind/solar profile is stochastically chosen for each day in the timeline by taking into account correlations with load and the wind/solar generation on the previous day**




+ **Each daily wind/solar profile in the historical sample set is assigned a 'similarity' rating to the day the wind/solar profile is being selected for**
  - Similarity is a function of 1) total daily load and 2) previous day's renewable generation
+ **Daily wind/solar profile is probabilistically chosen based on the similarity rating such that each monte carlo draw will yield a different combination of load and renewables while still preserving the underlying relationships between them**

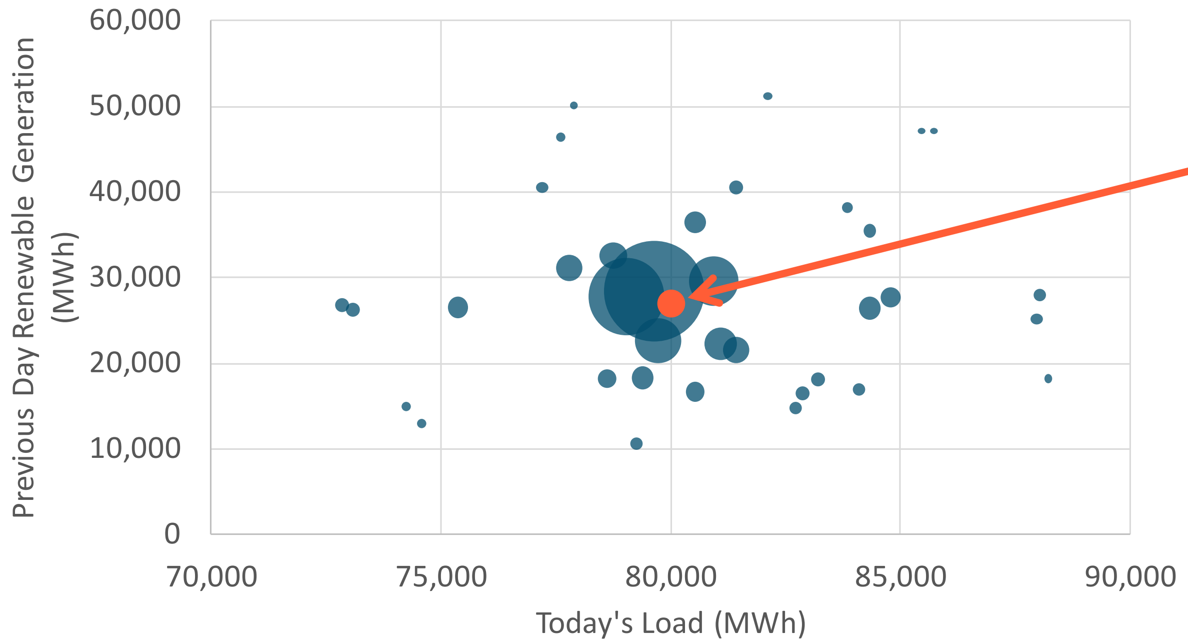
# RECAP Methodology
## Predicting Renewable Output (pt. 1)

+ To select a daily wind/solar profile, the model analyzes the load on the day as well as the previous 3+ days of wind/solar generation (with the most recent days being weighted highest)
+ The model searches through the actual load and wind/solar historical record to find similar days and assigns each daily wind/solar profile a similarity rating to the day being predicted based on load and preceding days' wind/solar
+ The model probabilistically selects a daily wind/solar profile through monte carlo analysis using similarity ratings as probability weights



## Predicting Renewable Output (pt. 2)

- Each blue dot represents a day in the historical sample
- Size of the blue dot represents the probability that the model chooses that day




| Aug 12, 1973 | |
|---|---|
| Today's Load | 80,000 MWh |
| Previous-Day Renewable Generation | 27,000 MWh |

**Probability Function Choices**

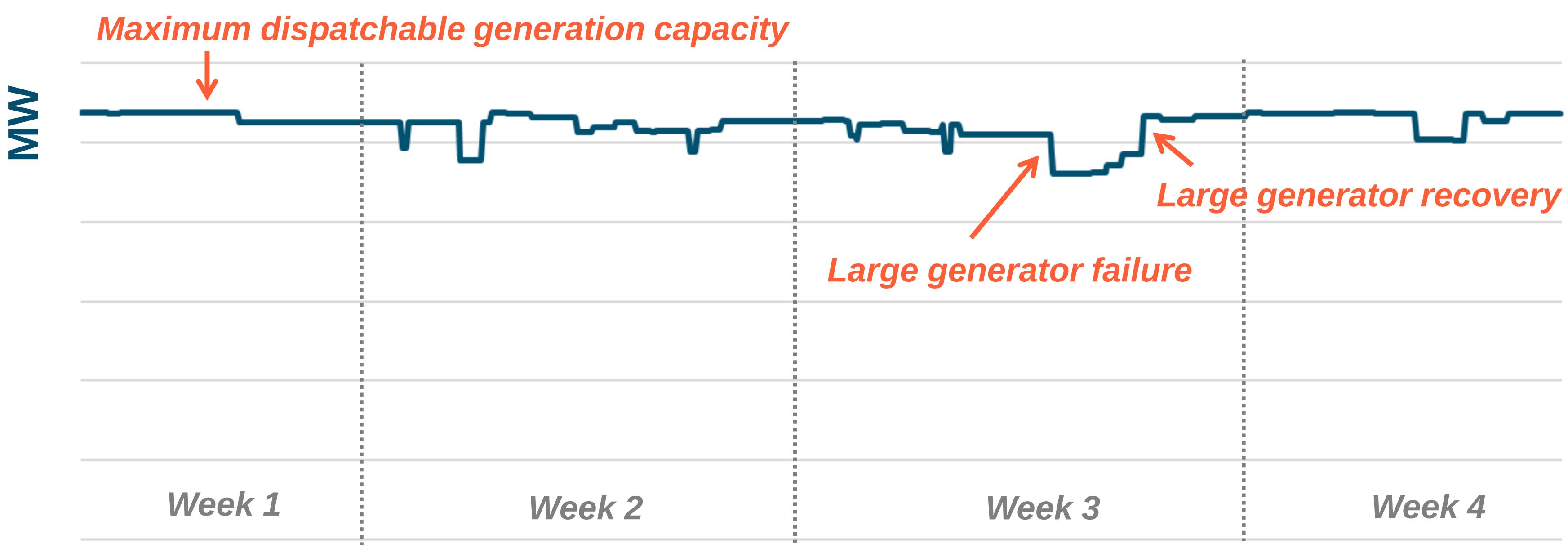
- Inverse distance
- Square inverse distance
- Gaussian distance
- Multivariate normal

*Probability of sample i being selected* $= \dfrac{\dfrac{1}{Distance_i}}{\sum_{j=1}^{n} \dfrac{1}{Distance_j}}$

*Where* $distance_i$ $=$ $\text{abs}[\text{load}_{\text{Aug 12}} - \text{load}_i]/\text{stderr}_{\text{load}} + \text{abs}[\text{renew}_{\text{Aug 12}} - \text{renew}_i]/\text{stderr}_{\text{renew}}$

- **Hourly dispatchable generator and transmission availability is calculated by stochastically introducing forced outages based on each generator's**
  - Forced outage rate (FOR)
  - Mean time to failure (MTTF)
  - Mean time to repair (MTTR)

**Total Available Dispatchable Generation**



# Factors That Affect the ELCC of Variable Resources

## + Coincidence with load

- Positive correlation with load means higher capacity value

## + Existing quantity of other resources

- Same or similar resource types have diversity penalty
- Complementary resource types have diversity benefit

## + Production variability

- Statistically, the possibility of low production reduces the value of a resource

## + Reliability target

- Effective capacity does not have linear relationship with system LOLE

# Appendix B: DR Program Data

# CAISO Bid Data

## Daily DR Shape Regression Stats

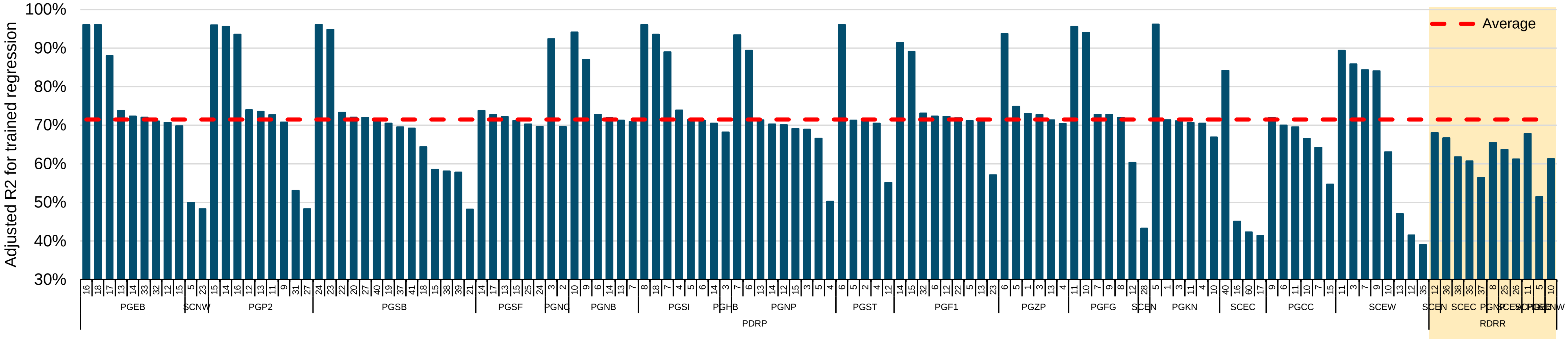
**+ Average performance of DR regression seems satisfactory**

- We may be overfitting in some instances given limited data for training and absence of regularization.
- Regression fit for RDRR programs consistently worse than average

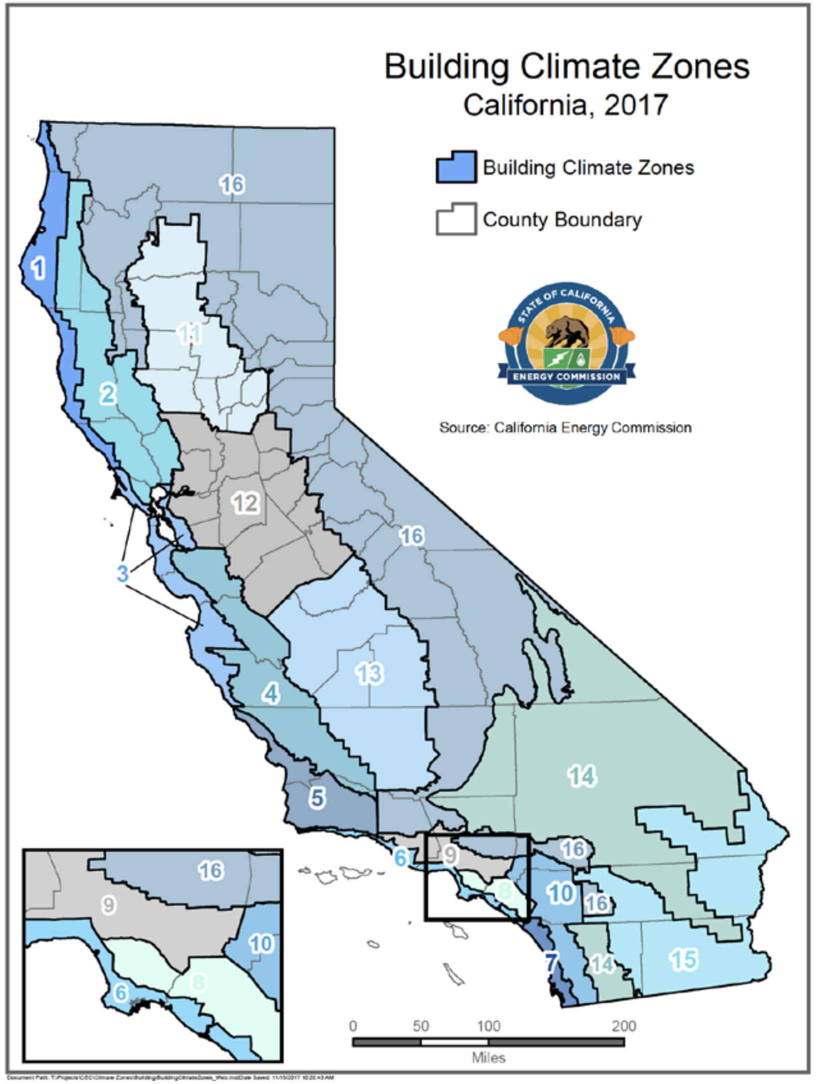
**+ Caveats:**

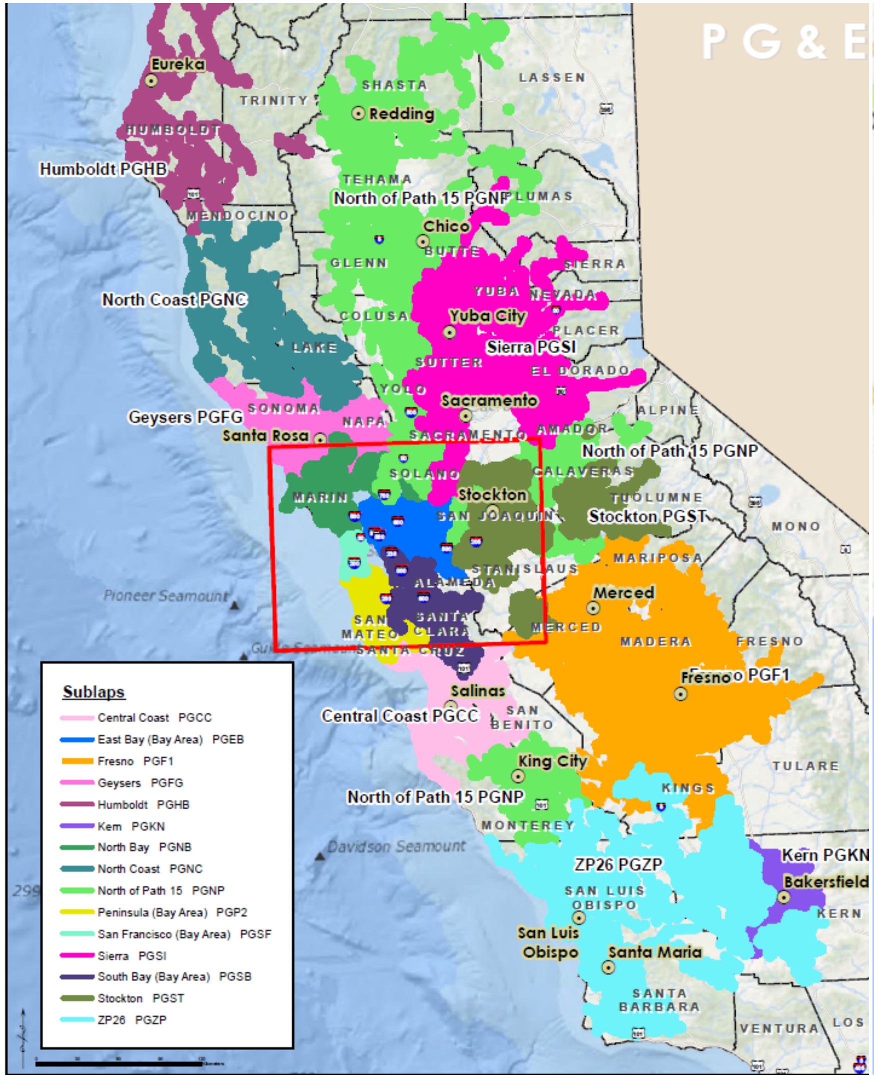
- Given that bid data is anonymized, we do not know whether underlying loads are best explained with our selected variables (daily temperature, month, day type)
- We assume the bids reflect total availability due to temperature
  - Unclear if bidding behavior of DR providers is influenced by factors such as # of calls remaining during the year

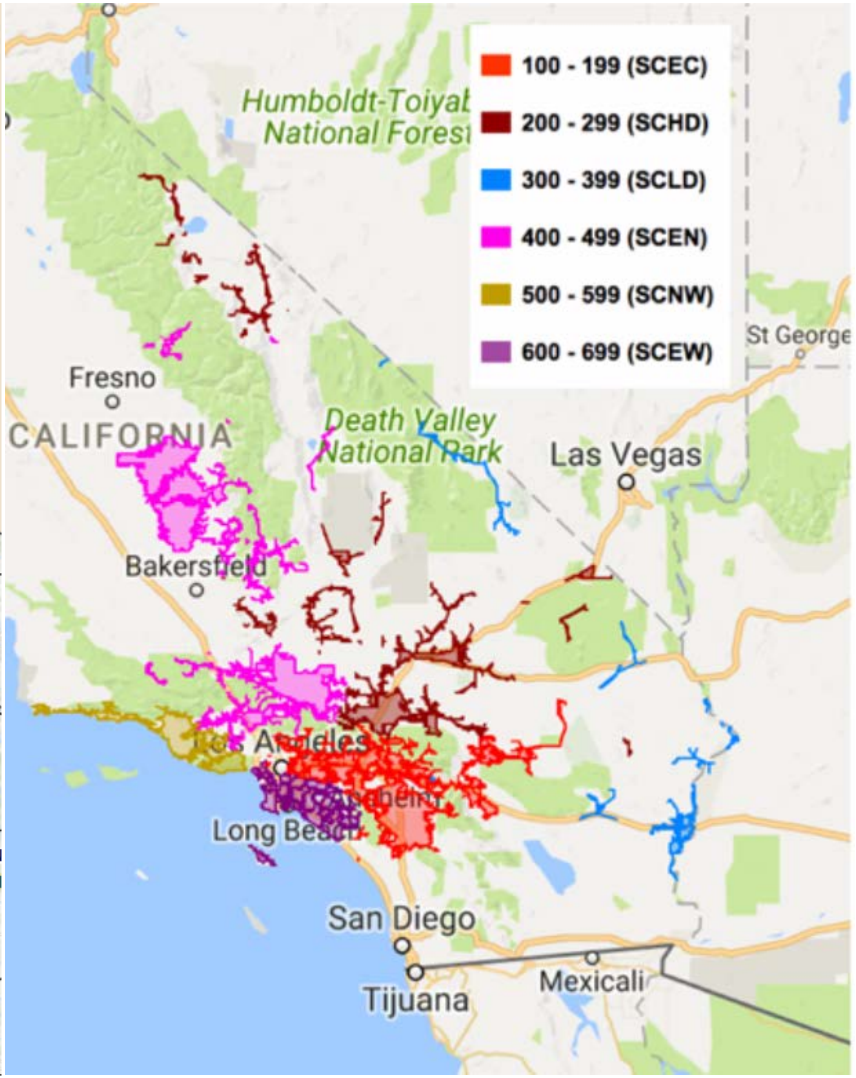
### R2 Results for Each DR Program Bid



# Climate zones and sub-LAPs for reference



# Sub-LAPs vs. Local Capacity Areas

| Sub-LAP | Sub-LAP (long form) | Local Capacity Area |
|---|---|---|
| **PGCC** | PG&E Central Coast | Bay Area |
| **PGEB** | PG&E East Bay | Bay Area |
| **PGF1** | PG&E Fresno | Greater Fresno |
| **PGFG** | PG&E Fulton-Geysers | North Coast/North Bay |
| **PGHB** | PG&E Humboldt | Humboldt |
| **PGKN** | PG&E Kern | Kern |
| **PGNB** | PG&E North Bay | North Coast/North Bay |
| **PGNC** | PG&E North Coast | North Coast/North Bay |
| **PGNP** | PG&E North of Path 15 - non local | CAISO System |
| **PGP2** | PG&E Peninsula | Bay Area |
| **PGSB** | PG&E South Bay | Bay Area |
| **PGSF** | PG&E San Francisco | Bay Area |
| **PGSI** | PG&E Sierra | Sierra |
| **PGST** | PG&E Stockton | Stockton |
| **PGZP** | PG&E ZP26 (between Path 15 and 26) -non local | CAISO System |
| **SCEC** | SCE Central | LA Basin |
| **SCEN** | SCE North (Big Creek) | Big Creek/Ventura |
| **SCEW** | SCE West | LA Basin |
| **SCHD** | SCE High Desert | CAISO System |
| **SCLD** | SCE Low Desert | CAISO System |
| **SCNW** | SCE North-West (Ventura) | Big Creek/Ventura |
| **SDG1** | SDG&E | San Diego/Imperial Valley |
| **VEA** | VEA | CAISO System |

# Assumptions on DR Program Characteristics

| Source | DR Program | Event Duration (hours/call) | Max. Events per Month | Max. Events per Year | Comments on RECAP Implementation |
|---|---|---|---|---|---|
| CAISO | PDR | 4 | 6 | | 24 hrs/month is interpreted as 6 events/month |
| | RDRR | 4 | | 30 | 15 events/season |
| PG&E | BIP | 6 | 10 | | |
| | CBP | 6 | 5 | | 30 hrs/month is interpreted as 5 events/month |
| | SAC | 6 | | 17 | 100 hrs/year is interpreted as 17 events/year |
| SCE | API | 6 | 7 | | 40 hours/month is interpreted as 7 events/month |
| | BIP | 6 | 10 | | 60 hours/month is interpreted as 10 calls/month |
| | CBP | 4 | 8 | | 30 hours/month is interpreted as 8 calls/month |
| | SDP | 6 | | 30 | 180 hours/year is interpreted as 30 events/year |

# PG&E Data Statistics

## 2018 PG&E DR Program Totals: Monthly NQC* (MW)

| Program Name | BIP | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Local Area | Greater Bay Area | Greater Fresno Area | Humboldt | Kern | Northern Coast | Sierra | Stockton | Outside LCA | ***Total IOU Service Area*** |
| **July** | 16.9 | 18.9 | 5.4 | 36.8 | 6.3 | 5.7 | 8.9 | 186.9 | ***285.8*** |
| **August** | 17.4 | 16.4 | 5.6 | 37.4 | 6.2 | 5.7 | 10.2 | 196.9 | ***295.7*** |
| **September** | 17.3 | 13.7 | 5.5 | 37.1 | 6.0 | 5.5 | 9.9 | 187.4 | ***282.3*** |

| Program Name | CBP Day Of and Day Ahead | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Local Area | Greater Bay Area | Greater Fresno Area | Humboldt | Kern | Northern Coast | Sierra | Stockton | Outside LCA | ***Total IOU Service Area*** |
| **July** | 6.4 | 1.3 | 0.2 | 2.7 | 0.5 | 0.6 | 1.4 | 6.3 | ***19.2*** |
| **August** | 6.4 | 1.3 | 0.2 | 2.7 | 0.5 | 0.6 | 1.4 | 6.3 | ***19.2*** |
| **September** | 6.4 | 1.3 | 0.2 | 2.7 | 0.5 | 0.6 | 1.4 | 6.3 | ***19.2*** |

| Program Name | AC Cycling Residential | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Local Area | Greater Bay Area | Greater Fresno Area | Humboldt | Kern | Northern Coast | Sierra | Stockton | Outside LCA | ***Total IOU Service Area*** |
| **July** | 20.0 | 11.5 | 0.1 | 5.8 | 4.0 | 8.0 | 8.6 | 18.3 | ***76.3*** |
| **August** | 19.0 | 11.0 | 0.2 | 5.6 | 3.4 | 7.5 | 8.2 | 17.3 | ***72.2*** |
| **September** | 19.1 | 10.0 | 0.1 | 5.0 | 3.4 | 6.8 | 7.5 | 15.9 | ***67.9*** |

## 2018 PG&E DR Shape Average Afternoon (1-6 PM) Availability (MW)

| Program Name | BIP | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Local Area | Greater Bay Area | Greater Fresno Area | Humboldt | Kern | Northern Coast | Sierra | Stockton | Outside LCA | |
| **July** | 63.3 | 16.4 | 3.2 | 48.9 | 5.3 | 12.1 | 13.5 | 72.4 | |
| **August** | 61.1 | 16.1 | 3.1 | 49.0 | 5.2 | 12.5 | 14.0 | 73.9 | |
| **September** | 61.3 | 14.9 | 2.8 | 48.4 | 4.8 | 12.6 | 13.6 | 72.0 | |

| Program Name | CBP Day Of and Day Ahead | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Local Area | Greater Bay Area | Greater Fresno Area | Humboldt | Kern | Northern Coast | Sierra | Stockton | Outside LCA | |
| **July** | 6.4 | 5.8 | 0.0 | 0.6 | 0.8 | 1.1 | 0.6 | 4.4 | |
| **August** | 5.3 | 7.0 | 0.0 | 0.8 | 0.7 | 1.2 | 0.5 | 4.8 | |
| **September** | 7.0 | 5.2 | 0.0 | 0.6 | 0.6 | 1.0 | 0.6 | 3.0 | |

| Program Name | AC Cycling Residential | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Local Area | Greater Bay Area | Greater Fresno Area | Humboldt | Kern | Northern Coast | Sierra | Stockton | Outside LCA | |
| **July** | 7.3 | 10.0 | | 3.3 | 0.5 | 7.2 | 3.6 | 7.0 | |
| **August** | 7.6 | 10.2 | | 3.0 | 0.4 | 6.9 | 3.2 | 6.2 | |
| **September** | 4.7 | 8.0 | | 3.0 | 0.2 | 5.5 | 2.8 | 4.7 | |

* Average Hourly Impacts (MW/hour) from 1pm to 6pm in Apr.-Oct. and from 4pm to 9pm Jan.- Mar. and Nov.-Dec. If Simultaneous Events Are Called on Monthly Peak Load Days Under 1-in-2 Weather Year Conditions, Before Adjusting for Avoided Line Losses

# SCE Data Statistics

## 2017 SCE DR Program Totals: Monthly NQCs*

| Program Name | Base Interruptible Program (BIP) 15 min & 30 min | | | | Agricultural and Pumping Interruptible (API) | | | | Capacity Bidding Program (CBP) Day Of & Day Ahead | | | | AC Cycling Residential and Commercial | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Local Area** | LA Basin | Big Creek/Ventura | Outside LCA | ***Total IOU Service Area*** | LA Basin | Big Creek/Ventura | Outside LCA | ***Total IOU Service Area*** | LA Basin | Big Creek/Ventura | Outside LCA | ***Total IOU Service Area*** | LA Basin | Big Creek/Ventura | Outside LCA | ***Total IOU Service Area*** |
| **July** | 488.5 | 75.9 | 73.7 | ***638.0*** | 14.4 | 30.1 | 22.1 | ***66.6*** | 22.7 | 5.2 | 3.1 | ***31.0*** | 200.5 | 27.7 | 33.6 | ***261.7*** |
| **August** | 512.9 | 76.1 | 69.9 | ***658.9*** | 16.0 | 26.0 | 21.3 | ***63.3*** | 22.7 | 5.2 | 3.1 | ***31.0*** | 249.5 | 28.2 | 33.5 | ***311.2*** |
| **September** | 466.3 | 71.7 | 72.6 | ***610.6*** | 14.7 | 19.3 | 15.7 | ***49.8*** | 22.7 | 5.2 | 3.1 | ***31.0*** | 211.2 | 21.2 | 23.7 | ***256.1*** |

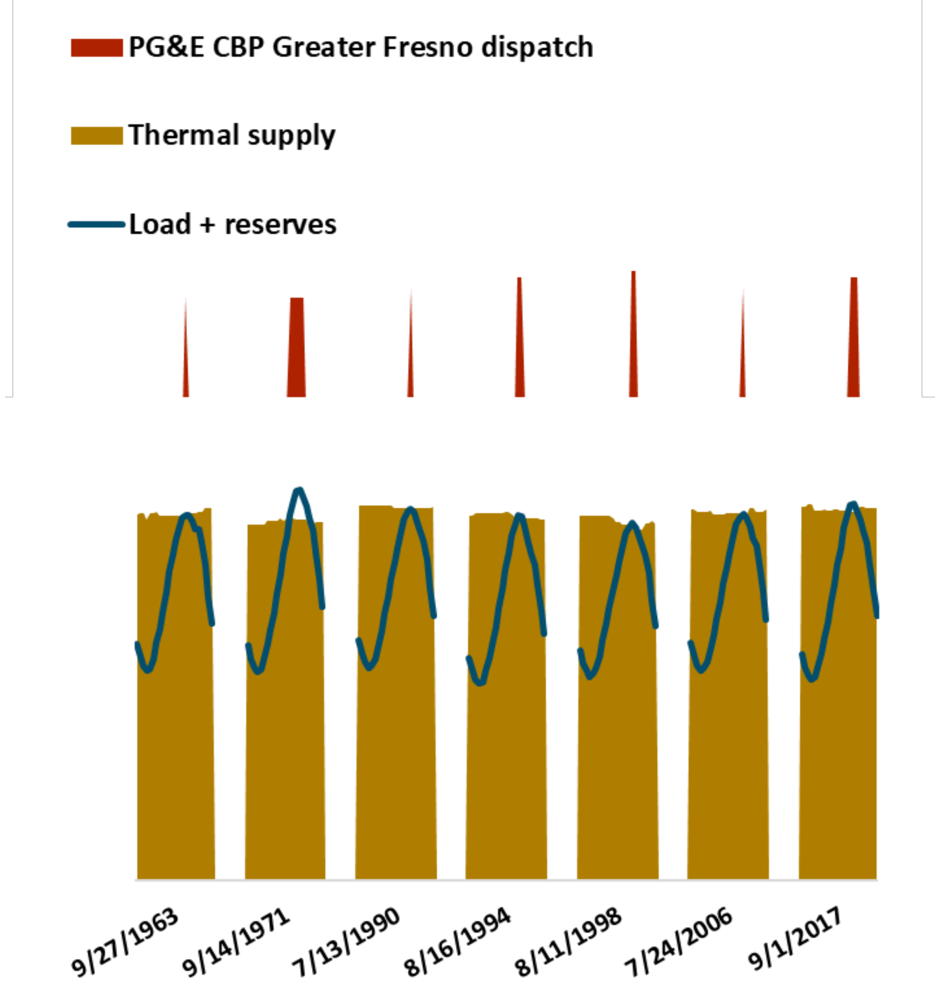
## 2017 SCE DR Shape Average Afternoon (1-6 PM) Availability (MW)

| Program Name | Base Interruptible Program (BIP) 15 min & 30 min | | | | Agricultural and Pumping Interruptible (API) | | | | Capacity Bidding Program (CBP) Day Of & Day Ahead | | | | AC Cycling Residential and Commercial | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Local Area** | LA Basin | Big Creek/Ventura | Outside LCA | | LA Basin | Big Creek/Ventura | Outside LCA | | LA Basin | Big Creek/Ventura | Outside LCA | | LA Basin | Big Creek/Ventura | Outside LCA | |
| **July** | 370.2 | 42.9 | 24.8 | | 7.2 | 43.1 | 3.2 | | 1.6 | 0.9 | 0.1 | | 161.0 | 33.7 | 14.4 | |
| **August** | 355.5 | 41.0 | 24.2 | | 6.5 | 43.1 | 3.0 | | 1.7 | 1.0 | 0.1 | | 164.4 | 30.8 | 12.7 | |
| **September** | 350.7 | 41.3 | 25.0 | | 5.0 | 37.2 | 2.3 | | 0.9 | 0.9 | 0.1 | | 127.4 | 17.8 | 6.3 | |

* Average Hourly Impacts (MW/hour) from 1pm to 6pm in Apr.-Oct. and from 4pm to 9pm Jan.- Mar. and Nov.-Dec. If Simultaneous Events Are Called on Monthly Peak Load Days Under 1-in-2 Weather Year Conditions, Before Adjusting for Avoided Line Losses

# Example PG&E CBP Greater Fresno Dispatch

DR dispatch during loss of load events for a system that meets the 0.1 LOLE reliability standard




| | CBP Greater Fresno Area | | |
|---|---|---|---|
| | Jul 2018 | Aug 2018 | Sep 2018 |
| NQC as per LIP | 1.25 | 1.25 | 1.25 |
| Median PG&E forecast | 8.9 | 9.7 | 8.2 |