BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Reforms and Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 21-10-002 (Filed October 7, 2021)

WORKSHOP REPORT ON FINAL PROPOSALS FROM REFORM TRACK PHASE 2 WORKSTREAMS 1 – 3 SUBMITTED BY PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

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Dated: November 15, 2022

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OF THE STATE OF CALIFORNIA

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Pursuant to Ordering Paragraph 28 of Decision 22-06-050 and the schedule set forth in the *Assigned Commissioner's Amended Scoping Memo and Ruling* filed on September 2, 2022, Pacific Gas and Electric Company, in its role as a co-facilitator of the Reform Track Phase 2 workshops, respectfully submits the attached workshop report on final proposals from Reform Track Phase 2 Workstreams 1 – 3.

Respectfully submitted,

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ATTACHMENT

Resource Adequacy Reform Working Group Report

Reform Track Phase 2 of the RA Proceeding, R.21-10-002

November 2022

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List of Acronyms

ACP-CA – American Clean Power - California
AReM – Alliance for Retail Energy Markets
BTM – behind the meter
CAISO – California Independent System Operator
CalCCA – California Community Choice Association
CalPA – Public Advocates Office of the California Public Utilities Commission, aka CalAdvocates
CalWEA – California Wind Energy Association
CAM – Cost Allocation Mechanism
CCA – Community Choice Aggregator
CEC – California Energy Commission
CEERT – Center for Energy efficiency and Renewable Technology
CESA - California energy Storage Association
CLECA – California Large Energy Consumers Association
CPA – Clean Power Alliance
CPE – Central Procurement Entity
CPM – Capacity Procurement Mechanism
CPUC – California Public Utilities Commission
DMM – Department of Market Monitoring
DR – demand response
DSA – Demand Side Analytics
DWR – California State Department of Water Resources
EBCE – EastBay Community Energy
ED – Energy Division of the California Public Utilities Commission
ELCC – effective load carrying capability
EO – energy-only
ESP – electric service provider
FCDS – Full Capacity Deliverability Status
GSCE – Golden State Clean Energy
HLM – hourly load model
IDS – Interruptible Deliverability Status
IEPA – Independent Energy Producers Association
IEPR – Integrated Energy Policy Report
IOU – investor-owned utility
IRP – Integrated Resource Planning
LOLE – loss of load expectation
LRA – Local Regulatory Authority
LSA – Large Scale Solar Association
LSE – load-serving entity
MCC – maximum cumulative capacity
MCE – Marin Clean Energy
MOO – must-offer obligation
MRP – Middle River Power
MW – Megawatt
MWD – Metropolitan Water District
NP 15 – north of Path 15

NQC – net qualifying capacity
NRDC – Natural Resources Defense Council
OASIS – open access same-time information system
PCDS – Partial Capacity Deliverability Status
PCE – Peninsula Clean Energy
POI – Point of Interconnection
PG&E – Pacific Gas and Electric Company
PRM – planning reserve margin
QC – qualifying capacity
RA – resource adequacy
RMD – Resource Master Database
RMR – Reliability Must Run
RPS – renewable portfolio standard
SCE – Southern California Edison Company
SCP - Sonoma Clean Power
SDG&E – San Diego Gas & Electric Company
SEIA – Solar Energy Industries Association
SERVM – Strategic Energy and Risk Valuation Model
SJCE – San Jose Clean Energy
SOD – slice-of-day
SP 15 – south of Path 15
SVCE – Silicon Valley Clean Energy
SWPG – Southwest Power Group
TAC – Transmission Access Charge
UCAP – Unforced Capacity
UFE – Unaccounted for Energy
VERS – variable energy resources
VS - Vote Solar
WPTF – Western Power Trading Forum

I. Introduction

Authors: PG&E

The Commission initiated Resource Adequacy (RA) reform efforts ("RA Reform") in R.19-11-009. Initial efforts involved several proposals and culminated with D.21-07-014 in which the Commission adopted PG&E's "slice-of-day" framework for RA Reform and directed additional development of the framework. The ensuing workshops and stakeholder discussions in 2021 and early 2022 (hereafter referred to as "RA Reform phase 1") culminated with a workshop report in February 2022 and D.22-06-050. In D.22-06-050 the Commission adopted SCE's 24-hour slice framework. Numerous elements of the RA Reform framework were decided as part of that decision and are outlined in Appendix A to that decision. Features of the framework addressed in D.22-06-050 include issues like the general structure, requirements setting process, storage functionality, several aspects of resource requirements, some resource counting issues, and more.

The Commission also recognized that additional development of the framework was needed and outlined three workstreams to develop further in workshops (hereafter referred to as "RA Reform phase 2"), which is the subject of this report. The workstreams are:

- Workstream 1. Develop 24-hour framework compliance tools:
  - Resource Adequacy (RA) Resource Master Database to be coordinated with California Independent System Operator (CAISO).
  - Load-Serving Entity (LSE) Showing Tool (template to be used by the LSE to make its filing to the Commission) and Commission Verification Tool (tool to be used by Energy Division to verify compliance).
  - LSE Requirement Database to be coordinated with the California Energy Commission (CEC). This will utilize outputs generated by the CEC's load forecast proposal, including a dry run filing that may inform any necessary changes.
  - Cost Allocation Mechanism (CAM) process and RA allocation to consider availability and capability of CAM-eligible resources and LSEs' load share during those slices.
- Workstream 2. Determine Planning Reserve Margin (PRM) and Counting Rules:
  - Appropriate exceedance level and hourly profiles for wind and solar at technology and/or location level.
  - Counting rules for hybrid, co-located, and long-duration energy storage resources, as well as development of an Unforced Capacity (UCAP) Evaluation-light mechanism, which only accounts for ambient derates, to be applied to dispatchable resources.
  - Elimination of the maximum cumulative capacity buckets.
  - Test year details.
  - Appropriate PRM with single PRM initially for all months and hours informed by a loss of load study, including National Resources Defense Council's calibration tool.
- Workstream 3. CAISO and Commission Validation and Compliance as follows:
  - Confirm elements of CAISO and Commission validation and compliance that do not require modification in the near term.

- Identify and resolve administrative changes to the RA program at both CAISO and the Commission (e.g., must-offer reporting, outage substitution).
- Elimination of the flexible RA requirements.

The Commission also outlined a schedule for the additional work in RA Reform phase 2, including workshops to resolve remaining implementation issues, a workshop report with final proposals, and a commenting period:

Table 1: Reform Track Phase 2 Schedule

Reform Track Phase 2 Schedule	
Milestone	Date
Workstreams 1 – 3 to resolve remaining implementation details and methodologies	July – October 2022
Final proposals from Workstreams 1 – 3 filed and served	November 15, 2022
Opening comments on final proposals	December 1, 2022
Reply comments on final proposals	December 12, 2022
Proposed decision on Reform Track Phase 2	First Quarter of 2023

This workshop report includes final proposals from the three workstreams. Efforts have been made to include comparisons of competing proposals, identify areas of consensus and non-consensus, and identify questions for parties to respond to in comments for areas that would benefit from additional development of the record.

II. Workshop Schedule

Authors: PG&E

Following D.22-06-050, co-facilitators from RA Reform phase 1 convened to outline a workshop schedule, including the scope of issues for each workshop, parties to facilitate the workshops, and parties to prepare and submit the workshop report to the Commission. Opportunities were provided to new co-facilitator participants and the final co-facilitator list for RA Reform phase 2 include representatives from the following parties: California Independent System Operator (CAISO), California Community Choice Association (CalCCA), California Energy Storage Alliance (CESA), California Large Energy Consumers Association (CLECA), Energy Division (ED), Independent Energy Producers (IEP), Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and the Western Power Trading Forum (WPTF). The co-facilitators developed a workshop plan and served it to the service list on July 18, 2022.

During the course of the workshops, the co-facilitators determined the final workshop, which had initially been a placeholder, was needed for further stakeholder presentation and discussion. In addition, D.22-08-039 was issued while workshops were underway, directing parties to develop proposals for how to use Demand Response Load Impact Protocols (LIP) in the 24-hour slice framework for the 2024 test year and include proposals within workstream 2 of RA Reform phase 2. Therefore, an additional workshop on Demand Response was added to the scope and schedule. The final schedule is included below.

Table 2: Final workshop schedule for RA Reform phase 2

Date	Workstream	Workshop Subject	Facilitator	Notetaker
Wed 7/27	2	Process Overview Resource Counting: exceedance for wind and solar	SDG&E	CLECA
Wed 8/3	1	Master Resource Database LSE Showing and Compliance Tools: initial discussion	IEP	CLECA
Wed 8/10	2	Resource Counting: hybrid resources	CalCCA	CLECA
Wed 8/17	2	Planning Reserve Margin (PRM): part 1 (process and mechanics) UCAP-Lite	CLECA	CAISO
Tues 8/23	2	Resource Counting: recap for wind, solar, hybrid; availability requirements for use-limited resources; long-duration storage; MCC Buckets for 2024	Energy Division Staff	CLECA
Wed 8/31	1	LSE Requirements: follow-up discussion (CEC data) Cost Allocation Mechanism (CAM) LSE Showing and Compliance Tools: follow-up discussion	CESA	CLECA
Mon 9/5		Labor Day Holiday	-	-
Wed 9/14	2	PRM: part 2 (counting values, setting requirements) Test Year: initial discussion	PG&E	CLECA
9/16	2	Utilization of LIP Outputs Under Slice of Day	Energy Division	-
Wed 9/21	3	Interface CPUC/CAISO Processes: changes to CIRA; single NQC Capacity Value Flexible Requirements	SCE	CLECA
Thu 9/29	Various	Test Year: follow-up discussion Remaining Issues	WPTF	CLECA
Thu 10/6	Various	Various Wrap-Up	PG&E	CLECA

III. Workstreams

a. Compliance Tools

i. Introduction

Authors: CLECA

In D.22-06-050[1], the Commission determined that the further development of its adopted 24-hourly Slice of Day (SoD) resource adequacy (RA) requirement should be undertaken in a second phase of the RA Reform Working Group process. This second phase was to include 3 workstreams. The first workstream was to address tools and profiles. More specifically, Workstream 1 addresses the following issues:

1. Tools: RA Resource Master Database, Solar and Wind Profile Master Database, Load Serving Entity (LSE) Requirement Database, LSE Showing Tool, and Commission Verification Tool.
2. Hourly load profiles after the California Energy Commission (CEC) finalizes monthly, 24-hour load shape for each LSE.

Tools:

RA Resource Master Database: The development of the RA Resource Master Database was to be coordinated with the California Independent System Operator (CAISO). There was discussion of which attributes of each resource should be included in the Database as needed for RA compliance and whether it would be useful to include other attributes so that the Database could be more broadly useful. SCE proposed a format for the Database in coordination with the Commission's Energy Division. ED decided not to use the CAISO Masterfile to populate this Database because of confidentiality issues. Instead, it will use default values and ask generators to make corrections. Then ED can compare the results to the CAISO Masterfile. If there are differences, ED will contact the generator. ED said if the 1Q23 decision concludes that additional information is needed, it will be included. The previous decision provided for a minimum number of fields. ED expects the Database will be updated annually as today for deliverability and Net Qualifying Capacity (NQC). Resources can be added to the NQC list when they come online. ED will assume that all batteries operate for 4 hours per cycle and parties can provide changes based on contract values.

Solar and Wind Profile Master Database: This Database, also called the Shapes Database, would provide a means of showing hourly solar and wind capacity by month. Proposals were made to have different shapes for different wind resources. LSE Showing Tool: SCE proposed an LSE Showing Tool which was discussed at the two Workstream 1 workshops as well as being referred to at others. The purpose of the Tool is to provide a consistent format for LSEs to make their SOD showings to the Commission on a 24-hourly basis for the worst day of each month. The Tool would assist with verification of compliance as discussed below. The Tool also includes an optimization feature. NRDC endorsed the SCE Tool but proposed amendments. Clean Power Alliance (CPA) presented a simplified showing tool. It has no optimization, instead using a logic test for sufficiency on an hourly basis and in aggregate. It is premised on the concept that showing is not required at the hourly level. CPA said its Tool can be used as an alternative compliance showing and contains alternative logic for sufficiency for single cycle storage.

Commission Verification Tool: The Commission Verification Tool is to be used by the Energy Division to verify LSE compliance with the SOD requirements. SCE's proposed LSE Showing Tool includes various internal tests for compliance in a dashboard format to assist the Energy Division's verification process.

[1] D. 22-06-050 at 108-109.

SCE's Tool also includes an optimization process to facilitate resource stacking by each LSE to show that it can meet its load plus planning reserve margin requirements.

Load Serving Entity Requirement Tool: LSEs submitted 24-hour load forecasts. The template was posted to the RA Compliance website 8-29-22. The CEC has gone through its load forecast adjustment process and has included initial results in the CEC section of the Proposal Summaries below.

CAM Process and RA Allocation: Energy Division stated that it intends to use the current process for allocation of RA for CAM resources and for DR.

ii. Master Resource Database, LSE Showing and Verification Tools, and LSE Requirements Database

Authors: SCE, with support from CPA, CESA, CEC, collaboration with ED

I. Background

In D.22-06-050, the Commission adopted three workstreams for further development of the 24-hour framework. Workstream #1 was focused on developing the 24-hour SOD Framework's compliance tools. Its scope included, in part: a) RA Resource Master Database to be coordinated with CAISO; b) LSE Showing Tool, i.e., the template to be used by the LSE to make its filing to the Commission and a Commission Verification Tool, i.e., the tool to be used by Energy Division to verify compliance; and c) LSE Requirement Database to be coordinated with the CEC, which would utilize outputs generated by the CEC's load forecast proposal, including a dry run filing that may inform any necessary changes.

II. Issues

Several tools are needed for successful implementation of the 24-hour SOD Framework, including:

- RA Resource Master Database,
- Solar and Wind Profile Master Database,
- LSE Showing Tool,
- Commission Verification Tool, and
- Load Serving Entity Requirement Tool.

III. Presenters and Dates

- August 3, 2022:
  - Energy Division
  - California Energy Commission (CEC)
  - SCE
- August 10, 2022:
  - CESA
- August 25, 2022:
  - CESA
- August 31, 2022:
  - Energy Division
  - SCE

- September 29, 2022:
    - SCE
- October 6, 2022:
    - CPA

IV. Proposal Summaries

The Energy Division staff and the CEC staff made presentations on the Master Database and LSE requirements-related topics. SCE presented an LSE Showing Tool which can also be used for compliance verification. NRDC proposed a few modifications. CESA proposed some clarifications to the Master Database, as well as consideration of an initial system-wide test to determine if LSE-by-LSE charging sufficiency verification for standalone storage is warranted. CPA presented an alternate LSE showing tool. These proposals and presentations are summarized below.

a. Energy Division

Authors: SCE

RA Resource Master Database: D.22-06-050 (Appendix A) noted that the development of the RA Resource Master Database should be coordinated with the California Independent System Operator (CAISO) to the greatest extent possible, to utilize the same unit information used by CAISO in its market operations (e.g., aligned with CAISO's Masterfile). After presenting several options on how the Database could be populated, Energy Division put forward its preferred option which was to populate the database using CAISO Masterfile data. However, upon further development, Energy Division determined it would not populate the Database using data from the CAISO's Masterfile due to confidentiality issues raised by CAISO and administrative complexity to track scheduling coordinator and generation owner affirmations to release the data. Energy Division presented a revised approach which would use public data sources and default values (instead of the Masterfile data) to populate the Database. This database would then be published on the CPUC website and sent to the service list with a request to generators to respond with any corrections (similar to the NQC process). Feedback from the suppliers would be incorporated into the Database and then compared to information in the CAISO's Masterfile. If there is a data mismatch, the Energy Division will contact the supplier to correct it.

Energy Division provided the following public sources and default assumptions that it would use to populate the Database:

- Data sources: Master generator capability list, NQC List, local sub area list, CAISO grid interconnection queue, other public information
- Default fields
    - All batteries will be assumed to be 4-hour, one cycle per day
    - Maximum daily energy will be 4 times August NQC
    - Storage efficiency will be set at a conservative value of 0.8
    - First and last hour available are assumed to be 1 and 24 for most resources
    - For hybrids, generic sub-IDs listed to facilitate showings of all components

Energy Division also presented a plan to send out an initial draft Master Resource Database request prior to a Q1 2023 decision and then again, after a Q1 decision is voted out. The second request will include any new fields (or changes) not included in the draft list.

At the workshops, there was also discussion of which attributes of each resource should be included in the Database as needed for RA compliance and whether it would be useful to include other attributes so that the Database could be more broadly useful. D.22-06-050 had provided for a minimum number of fields including resource ID, maximum RA capacity, hours of availability within a 24- hour window, solar and wind profiles, storage charging efficiency and maximum continuous energy, hybrid and co-located resource configurations. D.22-06-050 also provided that the database information would be public and available to inform trading and resource portfolio development. It was discussed that physical limitations and use limitations (for resources such as Demand Response and Hydro as well as any nighttime limitations on resource availability) would be included. The Energy Division expects the Database will be updated annually for deliverability and Net Qualifying Capacity (NQC). Resources can be added to the Database and NQC list when they come online. The Energy Division will assume that all batteries operate for 4 hours per cycle and parties can provide changes based on contract values.

In discussing the information and sources that would be used for the purposes of the Master Resource Database, CESA and Vistra underscored that sourcing efficiency data from existing datasets, such as the CAISO's Masterfile, could prove problematic as efficiencies are oftentimes embedded in an interrelated manner that affect other resource characteristics, such as the maximum continuous energy limit (MWh) available for dispatch. CESA recommended that the parameters needed for showing and validation be sourced from bilateral RA contracts. For storage, CESA envisions this information would include the maximum power output sustainable over the non-contiguous number of hours shown (MW) and the maximum continuous energy (MWh). In the workshop on this topic Gridwell clarified that round trip efficiency and maximum continuous energy limit are separate Masterfile parameters. The CAISO agrees that these two parameters are not commingled in the Masterfile.

In its presentation SCE suggested resource owners interested in providing RA Capacity in the CPUC's RA program should provide certain information to CPUC staff for the RA Resource Database. Resource ID, Technology, Online Date, Pmax, Pmin, Maximum daily run hours, Daily physical storage cycle capability, Storage Efficiency, Maximum continuous energy, daily hours available, and hybrid configuration information.

SCE also suggested the current single-monthly QC/NQC be retained in the CPUC Resource Database and LSE showing data until CAISO can complete its stakeholder process to choose a new representation of resource reliability contributions. For most resource types, the single monthly QC value will be equal to the maximum counting value under the CPUC 24-hour framework (e.g., thermal, geothermal, biomass, storage, hydro). For wind and solar, single-monthly QC values would be based on existing Effective Load Carrying Capacity (ELCC) values today, and resource profiles under the CPUC 24-hour framework can be adjusted to reflect hourly counting relative to the current single-monthly ELCC value for each technology. LSE showings will still be 24 hourly slices based on expected reliability contribution in that slice but by retaining the single-monthly QC compatibility with the CAISO RA system is maintained.

As SCE has built out example RA Resource Databases, LSE Showing Tools, and CPUC Validation tools it became clear Resource Profiles should be considered a sub-table of the RA Resource Database.

Solar and Wind (Variable Energy Resource) Profiles: D.22-06-050 (Appendix A) provided that monthly hourly profiles for solar and wind resources should be based on technology and/or general geographic region and included in the Master Resource Database. These profiles would provide a means of showing hourly solar and wind capacity by month. Proposals were made to have different shapes for different wind resources. In its tools and presentations, SCE suggests each resource should have a shape defined in a "Resource ELCC Shape Database".[2] Even though many resources will have flat shapes initially, configuring the CPUC RA tools with shapes for every resource allows the flexibility to adopt hourly Unforced Capacity (UCAP)/ELCC for each resource should it be required. SCE has configured the ELCC shape database with two different options: shapes relative to Pmax and shapes relative to the current single-monthly QC/NQC. If the single-monthly QC is retained for some time, as SCE has suggested in workshops, the shape for a resource multiplied by the single-monthly NQC will result in the hourly ELCC needed for LSE showings. If Pmax or some other value is used as the scalar, the shapes would just need to be adjusted so the hourly ELCC result is the same.

Commission Verification Tool: The Commission Verification Tool is to be used by the Energy Division to verify LSE compliance with the 24-hour SOD requirements. SCE's proposed LSE Showing Tool includes various internal tests for compliance in a dashboard format to assist the Energy Division's verification process. SCE's Tool also includes an optimization process to facilitate resource stacking by each LSE to show that it can meet its load plus planning reserve margin requirements.

b. SCE

Authors: SCE

LSE Showing Tool: SCE proposed an LSE Showing Tool which was presented during Workstream 1 workshops as well as discussed during other workshops. SCE has developed a spreadsheet tool that can be used by each LSE to submit its monthly, 24-hour showing to the Commission. This tool contains a standard format for listing the resources in an LSE's portfolio including the resource ID found in the Master Database, the MW quantity associated with the must offer requirement, and the capacity used in each of the 24 hours of the showing. This tool also includes pass/fail logic identical to the Commission Verification Tool, so that the LSEs would know in advance if they will pass Commission verification. SCE posits that this showing may also be used to provide the CAISO the information it will need to determine the must offer requirements of all resources, and the correct RA capacity values to use when performing their single hour deficiency test.

In summary, the purpose of the Tool is to provide a consistent format for LSEs to make their compliance showings to the Commission on a 24-hourly basis for the worst day of each month, as well as to assist with verification of LSE compliance.

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[2] "ELCC" in the compliance tools discussion refers to the hourly profile for wind and solar (and potentially) other resources that would be used in slice-of-day. It does not refer to existing ELCC values discussed in other sections of the report.

The Tool also includes an optimization feature. SCE's tool assumes that the Commission-required Resource Master Database (RMD) will contain a list of all resources (within the CAISO) eligible to sell RA, their resource ID, their maximum RA capacity, and hours of availability within a 24-hour window. For solar and wind, RMD would identify the profile associated with the resource. For storage, the RMD includes the charging efficiency and maximum continuous energy. For hybrid and co-located resources, RMD would include configurations to describe capabilities. Data would be available for each month, and the information would be public and available to inform trading and resource portfolio development. Similarly, the LSE Requirements Database would interface with the LSE Showing Tool and populate the LSE allocation tab with the official requirements of each LSE (hourly load + Planning Reserve Margin (PRM)), by month, for all 24 hours. This information would be used by each LSE to determine its monthly 24-hour showing requirement, while also being used by the Commission to ensure each LSE meets its monthly 24-hour showing requirement. SCE also presented the Validation Logic embedded in its tool, including resource tests for different technologies, a resource test for paired resources, tests to validate that the sum of showings for each slice meets or exceeds the reliability requirements, and an aggregate portfolio test.

SCE suggested the following validation logic for the LSE showing tool and Commission Verification tool:

<u>Resource Showing Validation:</u>

- Wind/Solar/Imports/DR
  - Showing in each slice <= appropriate hourly ELCC shape
- Geothermal/Biomass/Hydro/Thermal
  - Showing in each slice <= NQC (or appropriate shape if we're doing capacity exceedance shapes for everything)
  - Showing within daily availability hours
    - First hour available <= Showing hour <= Last hour available
  - Shown hours <= Maximum daily run hours
    - (Number of hours showing >0 MW) <= Maximum daily run hours
- Single-cycle storage
  - Showing in each slice <= NQC
  - Shown MWh <= Maximum continuous energy (Storage MWh)
- Multi-cycle Storage (if available)
  - Showing in each slice <= NQC
  - Shown continuous MWh <= Maximum continuous energy (Storage MWh)
  - Total shown MWh <= Storage resource maximum daily MWh
    - Pmax*(hours available per day/cycle length)
    - Cycle length = (1+1/storage efficiency)
  - "Downtime" hours immediately prior to storage showing block to support charge capacity
    - Shown "downtime" hours prior to showing block >= (Shown block MWh/storage efficiency)/Pmax
- Hybrid (storage only charges from associated renewable under normal circumstances)

- Hybrid showing should be bifurcated for ease of validation even if single resource ID
- Gross level validations:
    - Total MWh shown + storage efficiency losses <= total daily MWh of renewable portion
    - Sum of "Paired" showing in each slice <= interconnection limit
- Component level validations:
    - Storage component shown within storage capabilities (see storage validation)
    - Renewable component showing must have storage MWh and efficiency losses removed from appropriate shape
        - Renewable component showing in each slice <= appropriate shape
        - Renewable component total shown MWh + storage charging requirements <= appropriate shape MWh

<u>LSE Portfolio Tests</u>

- Sum of each slice showing >= reliability requirement in each slice
- Sum of slice showings + excess capacity for storage >= sum of reliability requirements
    - Excess capacity for storage is sum of each storage showing MWh/Each resource storage efficiency
- Non-slice-of-day
    - MCC bucket tests as appropriate
    - Flex RA tests as appropriate
    - Local RA tests as appropriate

<u>Aggregated Showing Tests</u>

- For each resource:
    - Sum of each hourly showing <= to relevant shape or NQC
        - Failures should be truncated in aggregated showing tests
    - Shown hours <= daily hour limit
- Aggregated:
    - Aggregated showing in each slice >= reliability requirement in slice

c. CPA

Authors: CPA

Clean Power Alliance (CPA) presented a separate LSE showing tool that is similar to SCE's with the stated goal of altering two main functions as compared to SCE's tools. The first change incorporated a temporal charging and Pmin component to the LSE validation tool with the goal of ensuring an LSE's excess energy needed to charge any storage resource would match the resource's actual charging parameters. The second change was intended to impact single-cycle energy storage resources with the goal being to reduce the burden on an LSE's need to manually manipulate hourly capacity values to determine compliance. This goal is achieved in the tool by determining an LSE's energy sufficiency to charge all an LSE's shown single-cycle energy resources in the aggregate across all hourly short positions.

d. CESA

Authors: CESA

CESA's Charging Sufficiency Verification Proposal: During the August 10 workshop, CESA argued for a system-wide test using energy-only resources be conducted in order to determine if each LSE needs to include charging capacity in their showings. This proposal is detailed on page 87, but is mentioned here as adoption of this proposal would have an impact on the LSE showing tool functionality.

e. CEC

Authors: CEC

Load Serving Entity Requirement Database: This database will contain the official RA requirements of each LSE (hourly load + PRM), by month, for all 24 hours. It will be used by the Commission and by LSEs to determine each LSE's 24-hour showing requirement. This database will be developed and managed by Energy Division in coordination with the California Energy Commission. The database will be non-public. However, each LSE will be provided access to its requirements.

The CEC discussed progress on the Dry Run forecast process directed by D.20-06-50. Forecast request templates were issued on August 5th and posted to the RA Compliance website, with forecasts due August 29th. LSEs were requested to provide a load forecast for 24 hours per month for the day of their own noncoincident peak. LSEs also had the option to provide an 8760-hour forecast instead, although only a few LSEs chose this option. A few LSEs also provided 24-hour load modifier forecasts.

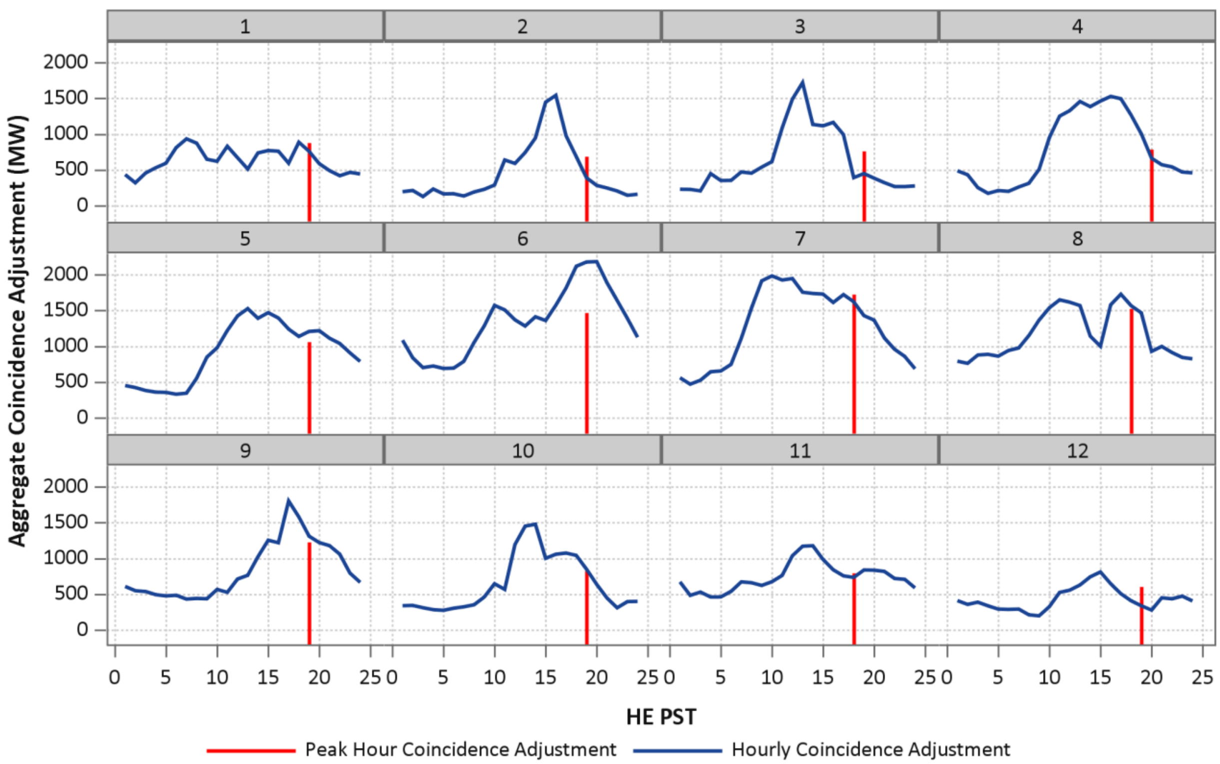
The CEC is adapting the current load forecast determination process, which allocates a share of its total load forecast to each LSE, to the 24-hour framework using the submitted forecasts. The CEC indicated summary results would be included as a part of this report if available. The remainder of this section describes the CEC staff's initial process and results.

For the reference forecast, which serves as the control total for aggregate CPUC-jurisdictional LSE forecasts, the CEC Integrated Energy Policy Report (IEPR) forecasts for the SCE and PG&E transmission access charge (TAC) areas must be disaggregated to CPUC and non-CPUC jurisdictional load. CEC staff is currently developing a version of the CEC hourly load model (HLM) model at the IOU service area level, but that work is still in progress. For this analysis, staff constructed a reference forecast by first subtracting the IEPR-forecasted Department of Water Resources (DWR) and Metropolitan Water District (MWD) loads from the HLM TAC area results. Next, staff subtracted peak day load shapes, developed from historic loads, for the aggregate of the remaining publicly owned utilities in the SCE and PG&E service areas. At the time of the CAISO system peak, the hourly reference forecast is a very close match for the coincident peak values originally developed for RA 2023.

The CEC staff removed the automatic transmission load adjustment from the forecast template since transmission losses may only apply to peak hours. LSE forecasts were adjusted for transmission losses during peak hours, and PG&E Unaccounted for Energy (UFE) in all hours. Staff will research further the appropriate transmission adjustment by hour.

CEC then applied an hour- and LSE-specific coincidence adjustment to LSE forecasts, comparable to the current approach. CEC conducts a statistical analysis of each LSE's hourly loads relative to the CAISO monthly system peak to estimate a coincidence adjustment to apply to monthly peak demand. In the monthly peak construct, coincidence adjustments are typically based on the median coincidence factor for the top 3 to 5 system peak days, where the coincidence factor is the LSE load in the applicable peak hour divided by the LSE's monthly peak. For the 24-hourly framework, CEC staff applied a similar evaluation of the distribution of coincidence factors during system peak hours, using the 80th or 90th percentile of the top 10 hours in either 2020 or 2021, depending on load and temperature conditions in the historic data. The graph below shows a comparison of the hourly method results with the aggregate adjustment used for the RA 2023 forecasts.

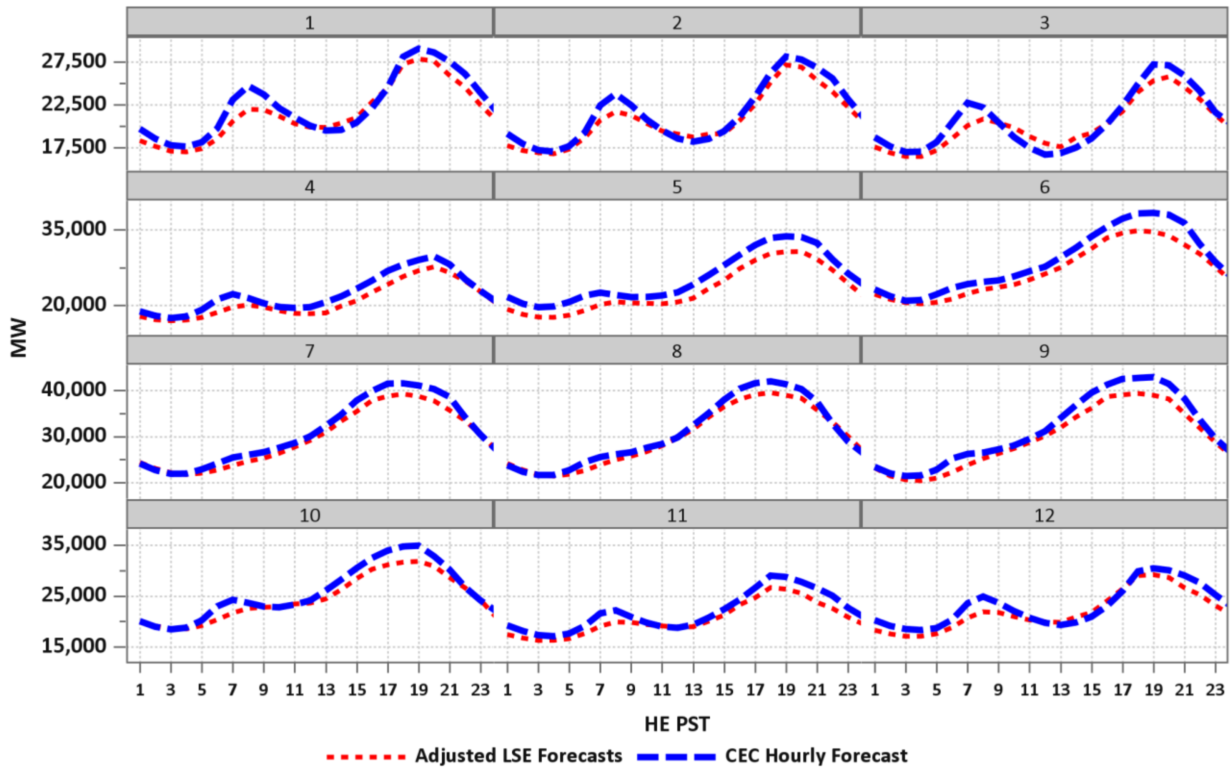
Figure 1: Comparison of Peak-Hour and Hourly Aggregate Coincidence Adjustments by Month



In most months, the system peak hour adjustment is close to that used in the year-ahead 2023 forecasts. However, the coincidence adjustments fluctuate significantly from hour to hour in some periods. This is also true of the individual LSE coincidence adjustment results. Staff intends to evaluate additional methods to produce a smoother coincidence adjustment so that LSE's final hourly load profiles follow a reasonable pattern.

As part of the current forecast review process, CEC staff sets a monthly peak benchmark for each LSE based on recorded loads, load migration activity, LSE forecast submittals, and weather-adjusted loads to guide its evaluation. LSE forecasts may be adjusted based on this analysis. For this initial test run, the RA 2023 peak adjustments were applied proportionately to peak period hours to assess the remaining deviations between the IEPR and LSE forecasts. The chart below shows the adjusted LSE forecasts compared to the reference forecast. During low-load hours, the LSE forecasts are close to or occasionally exceed the CEC forecast, but during peak periods, including morning peaks, the gap increases significantly. The final step in the forecast determination process is to adjust all forecasts so that the sum is within 1% of the reference forecast. For the forecasts calculated here, pro-rata adjustments are 3% or less during midday and late-night hours, but sometimes exceed 5% during morning and afternoon/evening peaks. CEC staff will need to develop methods to evaluate LSEs' forecasts outside of the peak period to reduce the size of the pro-rata adjustment and ensure fair cost allocation.

Figure 2: Comparison of Adjusted Monthly LSE forecasts with 2021 IEPR Reference Forecast



CEC staff will continue to refine and test forecast adjustment methodologies to allocate load appropriately in all hours. CEC staff will then share more detailed results and methodology for stakeholder consideration. If issues potentially requiring CPUC action are identified, such as changes or clarifications to the forecast determination process, staff will enter those issues into the record for a Q1 2023 decision.

V. Comparison of the proposals

Authors: SCE

This chapter covers proposals from the Energy Division and the California Energy Commission regarding various databases and proposals from SCE regarding various tools. CESA and CPA have proposed some modifications and enhancements to these tools and databases. As such, since these proposals are meant as alternatives, a comparison of proposals is not necessary.

VI. Consensus and non-consensus items

Authors: SCE

There is disagreement among workshop participants whether LSEs should be required to show excess RA capacity to provide charging for stand-alone storage, or whether non-RA capacity can be used for this purpose.

VII. Questions for parties

Authors: SCE, CPA

A few areas and related questions have emerged that warrant further clarification to successfully implement the 24-hour SOD Framework.

- <u>CAM Allocation</u>: How should Cost Allocation Mechanism (CAM) resources be allocated and impact any showing and/or validation tools and overall LSE compliance? For example, should they be allocated in a manner where the recipient can decide which hourly slice to show them in, or should the allocation occur in fixed hourly profiles without flexibility to show them in other slices?
- <u>DR Allocation</u>: How should IOU demand response (DR) resources be allocated among LSEs? How should such allocation impact any showing and/or validation tools and overall LSE compliance?
- <u>CAISO Backstop Procurement</u>: How should any CAISO backstop resources be allocated to LSEs? Should such allocation impact any showing and/or validation tools and overall LSE compliance?
- <u>Future Modifications</u>: What should the process be to adopt the necessary compliance and validation tools? What should the process be for changes to any required tools after the SOD program is launched?
- <u>Test Year</u>: Should any adopted compliance and validation tools be used in the test year to determine their feasibility and work out any problems or issues before the first full compliance year?

VIII. References

Authors:

- The workshop presentations referenced in this chapter are available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-history
- Energy Division's proposed Master Resource Database worksheet is available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/ra-reform-excel-workbooks/mrd-draft-clean.xls
- SCE's proposed Slice of Day Model is available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/ra-reform-excel-workbooks/sce-slice-of-day-24-slice-model-20220921.xlsx
- CPA's proposed Validation tool is available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/ra-reform-excel-workbooks/cpa_validation_tool_10042022.xlsx

iii. CAM, RMR, and DR Allocation Process

Authors: SCE, in collaboration with ED

I. Background

In D.22-06-050, the Commission adopted three workstreams to further develop the 24-hour framework. Workstream #1 was focused on developing 24-hour Slice Framework's compliance tools. Its scope included refining CAM process and RA allocation to consider availability and capability of CAM-eligible resources and LSEs' load share during those slices.

II. Issues

- <u>CAM allocation</u>: current CAM allocation is based on monthly peak load ratio so further discussion is warranted whether to continue to use the monthly peak load ratio to allocate the CAM portfolio for all slices as well as Reliability Must Run (RMR) and DR allocation.
- <u>Allocation by slice or resource</u>: further discussion is warranted on the feasibility, benefits, and drawbacks of assigning CAM portfolio either by slice or by resource and on how to ensure energy sufficiency requirements associated with CAM storage resources are equitably allocated to all LSEs

III. Presenters and Dates

- August 3, 2022:
  - Energy Division
- August 31, 2022:
  - Energy Division

IV. Proposal Summaries

a. Energy Division

Energy Division proposes to use monthly peak load ratio for CAM, RMR and DR allocations for all 24 slices to be consistent with how CAM costs are recovered from the customers. The CAM portfolio can be assigned to LSEs by slice or by resource (or aggregated resource level). If allocated by slice, then CAM allocations could vary hourly and this would mean having to hard code MW values for each hour. While administratively this option is preferable, easy to implement, and matches credits to debits evenly in all slices, this would not allow LSEs to show their share of the resource differently across hours. Energy Division proposes that CAM allocations be provided at a resource or aggregate resource level, so that LSEs have the flexibility to use the allocations to fit their individual hourly needs. Further evaluation is required on how much complexity this would add to the validation/compliance tools along with potential credit and debit mismatch to facilitate allocation of the CAM portfolio by resource to provide that flexibility to LSEs to choose the hours to show the resources for RA.

The 24-hour framework adds energy sufficiency requirements for energy storage resources. Under the current mechanism, investor-owned utilities (IOUs) would receive an energy sufficiency requirement associated with the entire CAM resource (rather than their portion of the CAM resource). Energy Division proposes equitable allocation of energy sufficiency requirements associated with CAM storage to Electric Service Providers (ESPs)/Community Choice Aggregators (CCAs).

V. *Questions for parties*

- Is there any downside to allocating CAM portfolio by monthly peak load ratio for all slices?
- If allocation is done by resource, how much complexity does this add to validation/compliance tools and how would one account for potential mismatches between credits and debits?

VI. *References*

Workshop presentations for this section are available at:

- August 3 presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-3-2022-lse-compliance-tools/workshop-2_ed_220803.pdf
- August 31 presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-31-2022-planning-reserve-margin/workshop-6_ed_220831.pdf

b. PRM and Counting Rules

i. Introduction

Authors: CLECA

D.22-06-050 specifies the following topics to be addressed in Workstream 2, whose focus was to be on how to determine the planning reserve margin (PRM) and what counting rules to be used to determine capacity values for various types of resources.

The specific topics listed in the decision are:

1. Appropriate exceedance level and/or hourly profiles for wind and solar and technology and location level.
2. Counting rules for hybrid, co-located, and long duration energy storage (LDES) resources, as well as development of an Unforced Capacity (UCAP)-light (ambient derate) mechanism to be applied to dispatchable resources.
3. Elimination of maximum cumulative capacity (MCC) buckets.
4. Test year details.
5. Appropriate PRM with single PRM initially for all months and hours informed by LOLE study, including NRDC's calibration tool.

<u>Exceedance Levels or Hourly Profiles</u>: This topic received a lot of discussion, particularly for wind resources. Several parties made specific exceedance proposals which are summarized later in this chapter. While positions did not converge, there was a clear convergence of direction in terms of seasonal exceedance levels for wind resources. Exceedance results were compared to Effective Load Carrying Capability (ELCC)-based values using the current ELCC methodology. For those supporting the use of exceedance values, there was general support for varying wind exceedance values by geographical region. Others felt that exceedance, although adopted by the Commission, was not ideal as it did not consider correlation with load. There was also concern about how exceedance values

would reflect output in days of very high loads. The CAISO was concerned about exceedance values that reflected solar and wind output on stressed system days. Others felt this was too rigid.

Counting Rules for Hybrid and Co-located Resources: The discussion of this topic seemed to converge on QC counting based on the size of the interconnection. There was considerable discussion of whether energy-only resources should be allowed to charge storage. The CAISO said that all RA resources must be deliverable. If behind-the-point of interconnection energy-only resources are used to charge storage and count for RA, these resources cannot be shown as RA and therefore will not be subject to CAISO RA rules. CESA proposed a framework to address the challenges posed by showing long duration energy storage resources and meeting the charging sufficiency verification.

Development of Unforced Capacity (UCAP)-light: This topic was not sufficiently developed to be included in this report or provide the basis for a Commission decision.

Elimination of Maximum Cumulative Capacity (MCC) buckets: There was support for elimination of MCC buckets except for demand response (DR) and imports. Energy Division presented proposals for how to calculate the cap for DR.

Test Year details: An issue related to the test year was raised about the need to make two different showings for the compliance year, one using the traditional showing and the other using the new 24-hourly showing. Parties were concerned that the two showings might require different resource mixes. Generators were concerned that they would have additional requirements and requested a punch list to be sure they could provide the appropriate information. There was also concern about changes between the 2024 and 2025 RA showings. Given changes for DR between 2024 and 2025, the showings for 2024 should be evaluated in late 2023 or very early 2024.

Appropriate PRM: There was a general conclusion that an appropriate PRM cannot be determined until the resource counting rules are chosen and a new loss of load expectation (LOLE) study which will be done for 2024. Energy Division has committed to do an LOLE study for 2024 by the end of January 2023. It will use existing and anticipated resources with no hypothetical resources. Since not all this information is available, further discussion focused on the interactions about the three variables and a process for developing a PRM when the counting rules are known and the LOLE study is completed. There was also discussion of whether the PRM could be determined on the basis of the highest load month and then applied to other months or whether there should be seasonal PRMs. One concern raised was whether basing an annual PRM on the highest load month inherently assumed that all resources under contract in that month would also be under contract for all months. Since this is not necessarily true, using the peak month PRM might result in insufficient resources in other months and leaning on non-RA resources.

ii. Resource Counting for Wind and Solar

Authors: PG&E, with support from NRDC, CalWEA, SEIA, ACP, CalPA, CAISO, MRP, collaboration with ED

I. Background

Authors: PG&E

In RA Reform phase 1, several parties made proposals for determining solar and wind profiles. These included PG&E, solar parties (SEIA, LSA, Vote Solar), CalWEA, and NRDC. PG&E proposed an exceedance-based approach benchmarked to average resource production on stressed grid days. The solar parties proposed an exceedance level that approximates the average ELCC of solar. CalWEA proposed a profile based on resource production during hours of the year when load is higher than a particular threshold, called the Effective Net Load Reduction (ENLR). NRDC proposed developing profiles based on stressed grid days using modeled data, called a "worst day" approach. In D.22-06-050, the Commission directed further development of PG&E's exceedance methodology as part of workstream 2. The decision noted that PG&E's recommendations were based on a limited set of data that required further development. The decision also noted that regardless of the methodology (exceedance or a high load day profile), there are challenges in determining where to set the exceedance level and how to define the high load day profile.

II. Issues

Authors: PG&E

Key issues include:

- Methodology:
  - Exceedance, with the level set based on resource production during high load days
  - Exceedance, calibrated to ELCC
  - High load day profile based on resource production during high load days
- Data source:
  - Recorded
  - Modeled
- Benchmarking and selection approach:
  - Use high load day profile or other approach
  - Definition of high load day profile
- Calibration approach:
  - None needed
  - Calibrate to ELCC
  - Calibrate within PRM tool
- Level to apply methodology
  - "Solar" and "wind" in aggregate
  - By region and/or technology
  - Individual resource

III. Presenters and Dates

Authors: PG&E

Solar and wind profile content was presented at three workshops:

- Workshop 1: July 27, 2022:
  - Energy Division
  - PG&E
  - CalWEA
  - SEIA

    - NRDC
    - ACP
- Workshop 5: August 23, 2022:
    - CalWEA
    - NRDC
    - PG&E
    - ACP / Pattern
- Workshop 10: October 6, 2022
    - CalPA
    - CalWEA
    - PG&E
    - CAISO
    - NRDC
    - MRP

IV. Proposal Summaries

a. PG&E

Authors: PG&E

PG&E's proposal is an exceedance-based seasonal approach in which a 70% exceedance level would apply to solar and wind resources across all hours in the summer months (June-September) and a 50% exceedance level would apply to solar and wind resources across all hours in the non-summer months (October-May). PG&E recommends using five years of recorded CAISO data and applying the methodology at the technology and geography level (i.e., fixed tilt and tracking for solar, NP15 and SP15, as well as out-of-state and offshore categories for wind). This proposed approach, introduced in workshop 10, replaced an earlier proposal to use a 70% exceedance level across all hours and all months, discussed in workshops 1 and 5. Note that PG&E also recommends testing PG&E's proposal within the PRM-setting tool to ensure that the approach isn't overly conservative or not conservative enough, as discussed in workshop 1.[3] This process could include testing of competing proposals to determine whether those approaches are more efficient in terms of resource value and PRM impact.

PG&E used a six-step methodology to arrive at its seasonal exceedance recommendation:[4]

1. Identify the top 5 highest load days in each month during each year of the recorded dataset[5]
2. Review solar and wind performance during those days (across all hours) and convert to capacity factors using net dependable or "interconnection" capacity at the time[6]
3. Average data across all years to arrive at a high-load day profile
4. Set up exceedance profiles using the recorded dataset

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[3] PG&E presentation, slide 7.

[4] Details on this approach can be found in PG&E's excel file, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/workshop-1---pge---exceedance-analysis---20220727.xlsx

[5] California ISO Open Access Same-time Information System (OASIS)

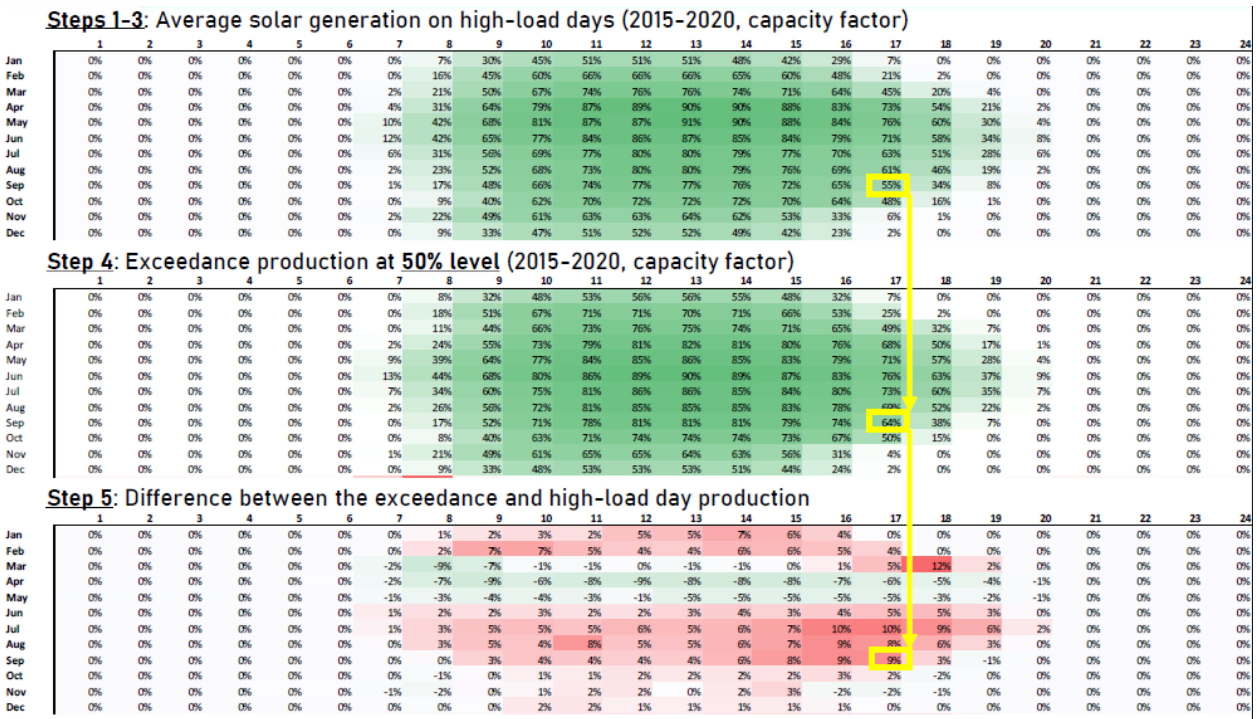
[6] Net Generating capacity data is from CAISO's master generating file.

5. Compare the high-load day performance to the exceedance production at a given level, with a focus on loss of load hours from IRP loss of load expectation (LOLE) studies[7]

6. Select the exceedance level that results in minor differences between that level and the high-load day profile in loss of load hours, while also ensuring simplicity

The following figure illustrates steps 1-5:

Figure 3: Process for comparing high load day profiles to exceedance levels



Steps 1-3: Average solar generation on high-load days (2015-2020, capacity factor)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0%	0%	0%	0%	0%	0%	0%	7%	30%	45%	51%	51%	51%	48%	42%	29%	7%	0%	0%	0%	0%	0%	0%	0%
Feb	0%	0%	0%	0%	0%	0%	0%	16%	45%	60%	66%	66%	66%	65%	60%	48%	21%	2%	0%	0%	0%	0%	0%	0%
Mar	0%	0%	0%	0%	0%	0%	2%	21%	50%	67%	74%	76%	76%	74%	71%	64%	45%	20%	4%	0%	0%	0%	0%	0%
Apr	0%	0%	0%	0%	0%	0%	4%	31%	64%	79%	87%	89%	90%	90%	88%	83%	73%	54%	21%	2%	0%	0%	0%	0%
May	0%	0%	0%	0%	0%	0%	10%	42%	68%	81%	87%	87%	91%	90%	88%	84%	76%	60%	30%	4%	0%	0%	0%	0%
Jun	0%	0%	0%	0%	0%	0%	12%	42%	65%	77%	84%	86%	87%	85%	84%	79%	71%	58%	34%	8%	0%	0%	0%	0%
Jul	0%	0%	0%	0%	0%	0%	6%	31%	56%	69%	77%	80%	80%	79%	77%	70%	63%	51%	28%	6%	0%	0%	0%	0%
Aug	0%	0%	0%	0%	0%	0%	2%	23%	52%	68%	73%	80%	80%	79%	76%	69%	61%	46%	19%	2%	0%	0%	0%	0%
Sep	0%	0%	0%	0%	0%	0%	1%	17%	48%	66%	74%	77%	77%	76%	72%	65%	55%	34%	8%	0%	0%	0%	0%	0%
Oct	0%	0%	0%	0%	0%	0%	0%	9%	40%	62%	70%	72%	72%	72%	70%	64%	48%	16%	1%	0%	0%	0%	0%	0%
Nov	0%	0%	0%	0%	0%	0%	2%	22%	49%	61%	63%	63%	64%	62%	53%	33%	6%	1%	0%	0%	0%	0%	0%	0%
Dec	0%	0%	0%	0%	0%	0%	0%	9%	33%	47%	51%	52%	52%	49%	42%	23%	2%	0%	0%	0%	0%	0%	0%	0%

Step 4: Exceedance production at **50% level** (2015-2020, capacity factor)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0%	0%	0%	0%	0%	0%	0%	8%	32%	48%	53%	56%	56%	55%	48%	32%	7%	0%	0%	0%	0%	0%	0%	0%
Feb	0%	0%	0%	0%	0%	0%	0%	18%	51%	67%	71%	71%	70%	71%	66%	53%	25%	2%	0%	0%	0%	0%	0%	0%
Mar	0%	0%	0%	0%	0%	0%	0%	11%	44%	66%	73%	76%	75%	74%	71%	65%	49%	32%	7%	0%	0%	0%	0%	0%
Apr	0%	0%	0%	0%	0%	0%	2%	24%	55%	73%	79%	81%	82%	81%	80%	76%	68%	50%	17%	1%	0%	0%	0%	0%
May	0%	0%	0%	0%	0%	0%	9%	39%	64%	77%	84%	85%	86%	85%	83%	79%	71%	57%	28%	4%	0%	0%	0%	0%
Jun	0%	0%	0%	0%	0%	0%	13%	44%	68%	80%	86%	89%	90%	89%	87%	83%	76%	63%	37%	9%	0%	0%	0%	0%
Jul	0%	0%	0%	0%	0%	0%	7%	34%	60%	75%	81%	86%	86%	85%	84%	80%	73%	60%	35%	7%	0%	0%	0%	0%
Aug	0%	0%	0%	0%	0%	0%	2%	26%	56%	72%	81%	85%	85%	85%	83%	78%	[illegible]	52%	22%	2%	0%	0%	0%	0%
Sep	0%	0%	0%	0%	0%	0%	0%	17%	52%	71%	78%	81%	81%	81%	79%	74%	64%	38%	7%	0%	0%	0%	0%	0%
Oct	0%	0%	0%	0%	0%	0%	0%	8%	40%	63%	71%	74%	74%	74%	73%	67%	50%	15%	0%	0%	0%	0%	0%	0%
Nov	0%	0%	0%	0%	0%	0%	1%	21%	49%	61%	65%	65%	64%	63%	56%	31%	4%	0%	0%	0%	0%	0%	0%	0%
Dec	0%	0%	0%	0%	0%	0%	0%	9%	33%	48%	53%	53%	53%	51%	44%	24%	2%	0%	0%	0%	0%	0%	0%	0%

Step 5: Difference between the exceedance and high-load day production

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	2%	5%	5%	7%	6%	4%	0%	0%	0%	0%	0%	0%	0%	0%
Feb	0%	0%	0%	0%	0%	0%	0%	2%	7%	7%	5%	4%	4%	6%	6%	5%	4%	0%	0%	0%	0%	0%	0%	0%
Mar	0%	0%	0%	0%	0%	0%	-2%	-9%	-7%	-1%	-1%	0%	-1%	-1%	0%	1%	5%	12%	2%	0%	0%	0%	0%	0%
Apr	0%	0%	0%	0%	0%	0%	-2%	-7%	-9%	-6%	-8%	-9%	-8%	-8%	-8%	-7%	-6%	-5%	-4%	-1%	0%	0%	0%	0%
May	0%	0%	0%	0%	0%	0%	-1%	-3%	-4%	-4%	-3%	-1%	-5%	-5%	-5%	-5%	-5%	-3%	-2%	-1%	0%	0%	0%	0%
Jun	0%	0%	0%	0%	0%	0%	1%	2%	2%	3%	2%	2%	3%	4%	3%	4%	5%	5%	3%	0%	0%	0%	0%	0%
Jul	0%	0%	0%	0%	0%	0%	1%	3%	5%	5%	5%	6%	5%	6%	7%	10%	10%	9%	6%	2%	0%	0%	0%	0%
Aug	0%	0%	0%	0%	0%	0%	0%	3%	5%	4%	8%	5%	5%	6%	7%	9%	8%	6%	3%	0%	0%	0%	0%	0%
Sep	0%	0%	0%	0%	0%	0%	0%	0%	3%	4%	4%	4%	4%	6%	8%	9%	9%	3%	-1%	0%	0%	0%	0%	0%
Oct	0%	0%	0%	0%	0%	0%	0%	-1%	0%	1%	1%	2%	2%	2%	2%	3%	2%	-2%	0%	0%	0%	0%	0%	0%
Nov	0%	0%	0%	0%	0%	0%	-1%	-2%	0%	1%	2%	2%	0%	2%	3%	-2%	-2%	-1%	0%	0%	0%	0%	0%	0%
Dec	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	2%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%

This example shows how a capacity factor-based profile for high load days (steps 1-3) can be compared to a given exceedance profile (step 4), using the differences in those profiles (step 5). In the example above, a positive number in red shading in the last table indicates that the exceedance level would provide too much value to the resource relative to how the resource has performed in a given high load hour. Given the amount of red, positive values in key evening hours in summer months in this example, one could conclude that a 50% exceedance level is not conservative enough.

The following figure illustrates how PG&E selected the 70% exceedance level for summer months. Blue boxes have been drawn around loss of load hours from a recent IRP LOLE study – which were concentrated in evening hours in August and September.[8] The 70% level generally results in small differences between the exceedance level and the high load day profile during these hours. The one exception is NP15 wind, which has some larger negative values in September (meaning 70% exceedance

[7] For this analysis, PG&E used: IRP MAG Webinar (7/19/22), ED, slide 71, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/20220719-fr-and-reliability-mag-slides.pdf

[8] *Id.*

is more conservative). However, PG&E believes the 70% level is still reasonable given that the positive values in August somewhat compensate for this difference.

Figure 4: Process for selecting exceedance level

70% Exceedance - High-load day profile for Solar

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0%	0%	0%	0%	0%	0%	0%	-1%	-6%	-6%	-5%	-2%	-2%	-3%	-4%	-6%	-2%	0%	0%	0%	0%	0%	0%	0%
Feb	0%	0%	0%	0%	0%	0%	0%	-1%	-1%	-2%	-4%	-5%	-4%	-6%	-5%	-3%	-2%	-1%	0%	0%	0%	0%	0%	0%
Mar	0%	0%	0%	0%	0%	0%	-2%	-13%	-14%	-11%	-9%	-11%	-10%	-11%	-13%	-11%	-6%	-11%	-3%	0%	0%	0%	0%	0%
Apr	0%	0%	0%	0%	0%	0%	-3%	-12%	-14%	-15%	-15%	-15%	-16%	-16%	-15%	-17%	-14%	-11%	-7%	-1%	0%	0%	0%	0%
May	0%	0%	0%	0%	0%	0%	-3%	-7%	-10%	-11%	-10%	-8%	-12%	-11%	-12%	-11%	-12%	-8%	-6%	-1%	0%	0%	0%	0%
Jun	0%	0%	0%	0%	0%	0%	-2%	-3%	-4%	-4%	-3%	-2%	-2%	-1%	-1%	-1%	-2%	-1%	-2%	-1%	0%	0%	0%	0%
Jul	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	2%	2%	2%	2%	3%	6%	5%	5%	3%	1%	0%	0%	0%	0%
Aug	0%	0%	0%	0%	0%	0%	0%	-1%	0%	0%	4%	0%	0%	1%	3%	4%	3%	2%	-1%	-1%	0%	0%	0%	0%
Sep	0%	0%	0%	0%	0%	0%	0%	-2%	-3%	-2%	-1%	-1%	-1%	0%	2%	3%	1%	-2%	-4%	0%	0%	0%	0%	0%
Oct	0%	0%	0%	0%	0%	0%	0%	-3%	-5%	-5%	-5%	-3%	-3%	-2%	-2%	-3%	-3%	-4%	-1%	0%	0%	0%	0%	0%
Nov	0%	0%	0%	0%	0%	0%	-1%	-5%	-7%	-6%	-5%	-4%	-6%	-6%	-6%	-7%	-3%	-1%	0%	0%	0%	0%	0%	0%
Dec	0%	0%	0%	0%	0%	0%	0%	-2%	-7%	-7%	-6%	-6%	-5%	-6%	-7%	-5%	-1%	0%	0%	0%	0%	0%	0%	0%

70% Exceedance - High-load day profile for SP15 Wind

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	-12%	-12%	-12%	-12%	-12%	-12%	-12%	-11%	-10%	-9%	-9%	-11%	-12%	-13%	-14%	-14%	-15%	-14%	-13%	-13%	-13%	-13%	-14%	-15%
Feb	-15%	-15%	-15%	-13%	-12%	-12%	-12%	-11%	-12%	-14%	-16%	-16%	-18%	-18%	-17%	-16%	-14%	-13%	-12%	-12%	-12%	-10%	-11%	-12%
Mar	-7%	-6%	-6%	-7%	-5%	-3%	-3%	-4%	-5%	-6%	-7%	-7%	-5%	-6%	-9%	-8%	-7%	-5%	-4%	-5%	-7%	-7%	-7%	-9%
Apr	-4%	-4%	-3%	-4%	-3%	-4%	-4%	-4%	-4%	-3%	-3%	-3%	-3%	-3%	-3%	-4%	-1%	1%	-2%	-2%	-1%	-3%	-3%	-4%
May	-8%	-9%	-7%	-5%	-6%	-6%	-4%	-5%	-4%	-3%	-3%	-2%	-2%	-3%	-2%	-1%	1%	1%	0%	-1%	-3%	-3%	-3%	-3%
Jun	6%	5%	6%	4%	4%	4%	4%	2%	1%	-1%	-1%	-1%	-2%	-3%	-3%	-1%	1%	3%	4%	5%	3%	1%	2%	3%
Jul	-3%	-3%	-3%	-4%	-4%	-4%	-4%	-4%	-3%	-3%	-2%	-2%	-2%	-3%	-4%	-4%	-4%	-3%	-3%	-4%	-3%	-3%	-4%	-3%
Aug	-3%	-3%	-3%	-3%	-5%	-4%	-3%	-3%	-3%	-3%	-2%	-3%	-3%	-4%	-5%	-5%	-5%	-5%	-4%	-3%	-2%	-2%	-2%	-3%
Sep	-3%	-4%	-4%	-5%	-3%	-3%	-3%	-2%	-2%	-2%	-2%	-3%	-3%	-4%	-5%	-9%	-8%	-6%	-5%	-5%	-7%	-6%	-7%	-8%
Oct	-1%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%	-3%	-3%	-3%	-3%	-3%	-4%	-4%	-5%	-4%	-4%	-5%	-4%	-5%	-6%
Nov	-6%	-5%	-5%	-4%	-4%	-3%	-3%	-3%	-3%	-3%	-4%	-4%	-6%	-6%	-7%	-7%	-8%	-7%	-6%	-6%	-6%	-7%	-7%	-7%
Dec	-12%	-11%	-11%	-11%	-10%	-10%	-10%	-10%	-11%	-12%	-12%	-13%	-14%	-15%	-15%	-15%	-14%	-13%	-12%	-11%	-12%	-11%	-11%	-9%

70% Exceedance - High-load day profile for NP15 Wind

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	-9%	-9%	-10%	-11%	-12%	-12%	-12%	-12%	-12%	-9%	-8%	-8%	-9%	-11%	-13%	-13%	-11%	-12%	-13%	-15%	-13%	-12%	-12%	-11%
Feb	-22%	-24%	-23%	-23%	-21%	-20%	-20%	-21%	-23%	-24%	-24%	-24%	-22%	-21%	-20%	-18%	-13%	-13%	-15%	-15%	-16%	-16%	-16%	-17%
Mar	-12%	-11%	-10%	-12%	-15%	-13%	-12%	-12%	-11%	-12%	-13%	-12%	-11%	-14%	-16%	-16%	-19%	-20%	-19%	-18%	-21%	-20%	-20%	-18%
Apr	-17%	-17%	-16%	-17%	-18%	-15%	-14%	-14%	-13%	-12%	-11%	-9%	-8%	-8%	-9%	-11%	-14%	-14%	-14%	-14%	-14%	-15%	-16%	-22%
May	-11%	-11%	-11%	-12%	-12%	-13%	-12%	-10%	-9%	-12%	-12%	-9%	-11%	-10%	-7%	-9%	-6%	-3%	-2%	-8%	-13%	-13%	-14%	-16%
Jun	-10%	-7%	-8%	-7%	-5%	-5%	-6%	-7%	-7%	-5%	-7%	-7%	-6%	-5%	-6%	-7%	-7%	-4%	-4%	-7%	-9%	-11%	-10%	-11%
Jul	0%	-1%	-2%	-3%	0%	1%	-2%	-3%	-4%	-4%	-4%	-4%	-5%	-7%	-7%	-7%	-2%	0%	2%	3%	2%	2%	0%	-1%
Aug	9%	8%	5%	0%	3%	4%	2%	0%	-1%	-2%	-5%	-5%	-5%	-3%	-5%	-3%	0%	0%	2%	6%	5%	3%	0%	0%
Sep	-11%	-10%	-11%	-12%	-10%	-12%	-14%	-14%	-14%	-11%	-10%	-9%	-8%	-7%	-8%	-10%	-11%	-12%	-14%	-16%	-17%	-20%	-22%	-21%
Oct	-9%	-10%	-14%	-13%	-13%	-13%	-11%	-10%	-9%	-10%	-11%	-11%	-10%	-10%	-10%	-10%	-9%	-9%	-10%	-12%	-13%	-15%	-14%	-14%
Nov	-9%	-8%	-7%	-5%	-4%	-4%	-3%	-3%	-3%	-3%	-3%	-2%	-5%	-5%	-5%	-6%	-6%	-7%	-8%	-7%	-9%	-10%	-12%	-13%
Dec	-17%	-16%	-16%	-15%	-15%	-16%	-16%	-14%	-13%	-13%	-14%	-14%	-15%	-14%	-12%	-11%	-10%	-10%	-9%	-9%	-9%	-10%	-10%	-11%

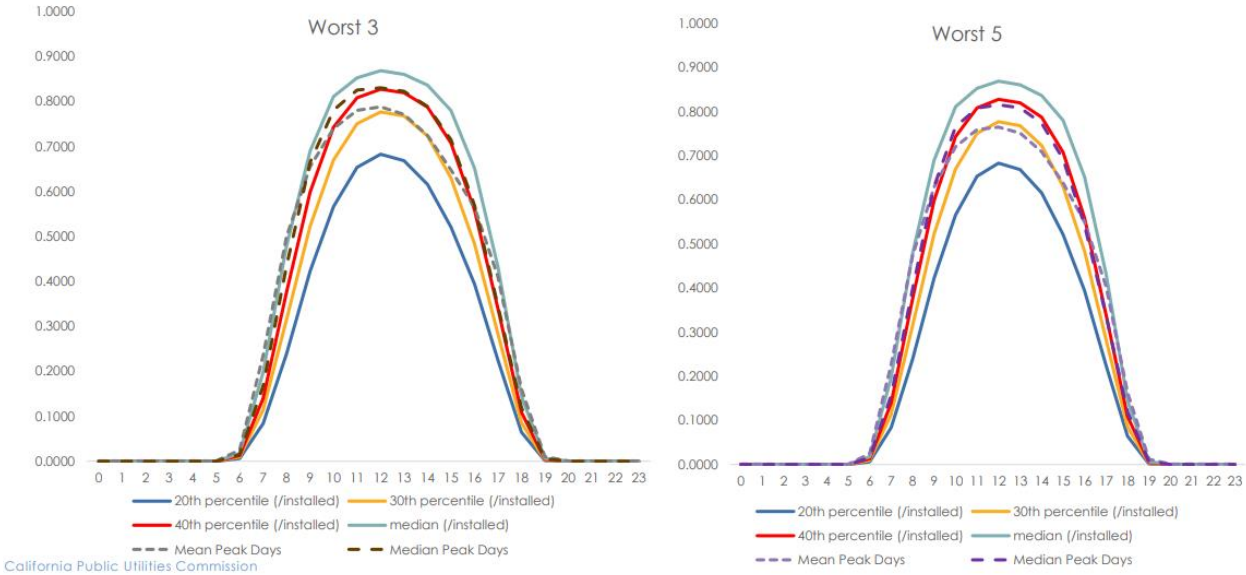
Lastly, while PG&E believes the proposed seasonal exceedance approach to be a reasonable starting point, PG&E recommends testing this proposal within the PRM setting tool to ensure it isn't too conservative, or not conservative enough. This process would involve testing PG&E's proposal along with other proposals within the PRM setting tool to test the impact on the PRM from changing the wind and solar proposals. Each proposal would be tested separately for wind and then solar holding all other assumptions constant. The change in the PRM for each test could be compared to the change in the average capacity factor of the resource to help the Commission determine the approach that best balances the resource value and PRM impact.

b. ED

Authors: PG&E

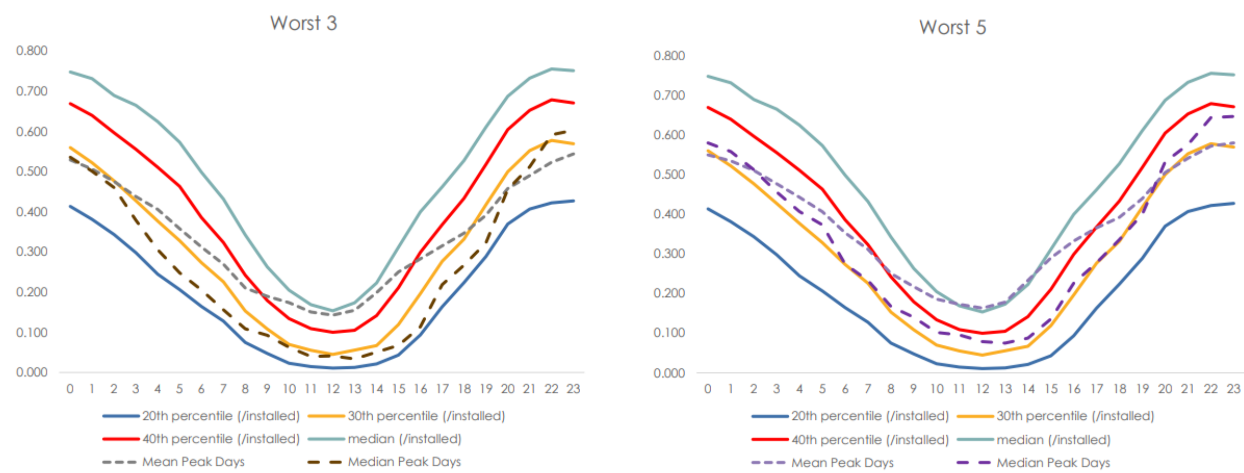
Energy Division presented analysis at workshop 1 of different exceedance levels for five years of solar and wind resource output. It included 50%, 60%, 70%, and 80% exceedance levels across a number of categories: fixed, tracking, and solar thermal for solar; north, south, and Arizona / New Mexico for wind. The analysis also included a comparison to the 3 and 5 days with the highest peak loads in each month. The high load day comparison included a mean and median of the high load day data. The figures below illustrate the results of this analysis for solar and wind resources.

Figure 5: August South Fixed PV Exceedance vs. Mean and Median of Worst 3 and 5 Days



One can see that the median peak day profile aligns fairly well with the 60% exceedance level (40th percentile), while the mean peak day profile aligns fairly well with the 70% exceedance level (30th percentile).

Figure 6: August North Wind Exceedance vs. Mean and Median of Worst 3 and 5 Days



One can see that while the median peak day profile aligns fairly well with the 70% exceedance level, the mean peak day profile varies substantially over the course of the day.

c. NRDC Resource Counting Methodologies Proposals

Authors: NRDC

Natural Resources Defense Council (NRDC) has been active in the development of resource counting profiles throughout the workshop series, presenting analysis and recommendations to develop a robust, durable, accurate, and fair resource counting structure for solar and wind resources. NRDC has consistently supported an approach to variable energy resource counting which reflects the expected contributions of variable energy resources during periods of grid stress[9], specifically, the narrow tail events which drive loss of load risk due to extreme demand, resource constraints, or other operational considerations.

Following extensive discussions on the use of exceedance to develop resource profiles, including multiple workshop presentations[10,11,12,13] and the development of multiple tools analytical tools[14,15] to compare and assess the impacts of different counting methods, NRDC concluded that the development of alternative statistical methods to exceedance could result in more robust, accurate, and durable resource counting methods. NRDC proposed two alternate counting methodologies, *Worst Day Profiles* and *Loss of Load Expectation Study Informed Profiles*, which are intended to more accurately sample and synthesize resource counting profiles relative to exceedance. Both approaches are designed to be used with the extensive modeled demand and resource data set developed by Energy Division and used within the SERVM model to calibrate portfolio needs.

Worst Day leverages a similar process to PG&E's proposed *Peak Day* methodology with two critical differences. The *Worst Day* methodology uses the following steps:

- **Data:** Utilize Energy Division's SERVM dataset (1997-2020), which includes weather-normalized renewable output and load
- **Subset:** Subset days across all years to the highest 2.5% (*alt: 1-5%*) of "Worst Days" for each month, defined as days experiencing highest gross load (*alt: net load*)
- **Synthesize:** For all days within the subset, take the mean output by month-hour to produce a synthesized resource profile

In contrast to PG&E's Peak Day methodology, NRDC's Worst Day methodology samples the highest load days across multiple years, focusing the data on extreme years and excluding mild observations from non-extreme years. Secondly, NRDC's Worst Day methodology does not include the final exceedance matching step proposed in the Peak Day methodology, raising the concern that this step introduces

[9] NRDC Informal Comments on Slice of Day Workshops, November 10, 2021.

[10] Renewables and Exceedance – A Primer, September 22, 2021. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/ra_t3b2_workshop-1_presentation-np.pdf

[11] Resource Counting for Preferred Resources, October 20, 2021. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-3-np-energy-nrdc_presentation-resource-counting-slides.pdf

[12] Slice of Day Resource Counting – Exceedance, July 27, 2022. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/7-27-2022-solar-and-wind-exceedance/workshop-1_nrdc_220727.pdf

[13] Slice of Day Resource Counting – Recap, August 23, 2022. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-23-2022-planning-reserve-margin/workshop-5_nrdc_220823.pdf

[14] NRDC Resource Profile Comparison Tool, appended to NRDC Comments [March 2022]

[15] NRDC PRM Calibration Tool, appended to NRDC Comments [March 2022]

significant and unnecessary error in all hours for which the selected exceedance methodology is not a good match for the Peak Day results.

The *LOLE-Informed Methodology* is conceptually very similar to the worst day approach, but directly leverages the outputs of the LOLE-modeling used to develop the underlying portfolio. The *LOLE-Informed* methodology uses the following steps:

- **Data:** Utilize the processed results of Energy Division's SERVM model runs
- **Subset:** Subset days across all runs which experience LOLE events; for months without observed LOLE or with fewer LOLE observations than a desired threshold, subset the top 1% of days by net load or by narrowest supply margin
- **Synthesize:** For all days within the subset, take the mean output by month-hour to produce a synthesized resource profile

Both Worst Day and LOLE-Informed follow similar conceptual intent to arrive at resource profiles which are:

- Based on robust, well-developed datasets used for the foundational modeling performed within the LOLE study
- Appropriately subsetted to the narrow set of observations that truly matter for reliability modeling – critical days with the potential for reliability risk
- Appropriately synthesized to retain fidelity across all hours within the subset of critical days of importance

These critical design goals are discussed further below.

Use of Modeled Data: Both approaches leverage the extensive work performed by Energy Division to develop synthetic load and resource profiles as key inputs to the LOLE-modeling analysis which undergirds the entirety of the RA program. While it would, in theory, be preferable to use historical observations of resource performance, such data are limited for all resources and non-existent for many emerging resources, particularly emerging wind regions which may use different turbine configurations or technology than exists in the existing datasets.

Using modeled resource performance calibrated to real-world observations is, for better or worse, unavoidable in stochastic LOLE modeling, and it is reasonable to extend the use of robust modeled datasets to the development of resource profiles, similar to the long-standing use of modeled data to develop ELCC values for solar and wind. Both Worst Day and LOLE-Informed approaches recognize this limitation, and are designed for use with modeled data, though Worst Day could be calibrated with historical data for solar and in-state wind subsetted using modeled load. As additional historical observations become available, the modeled data should be compared and revised at appropriate intervals.

Subsetting: Reliability modeling is fundamentally an exercise in understanding and mitigating tail risk – the risk of reliability events that occur when the long tails of weather and operational constraints converge to generate the potential for loss of load events. In California, this has largely been driven by extreme load on hot, late-summer days, with risk focused in the evening period, which can be approximated as observations of high gross or high net peak load, or observed directly in an LOLE model as LOLE risk or a narrow supply margin.

Both *Worst Day* and *LOLE-Informed* approaches offer a very specific focus on these grid stress days, either observed through a proxy – gross or net load peaks for each day – or directly through LOLE risk or supply margin if using the outputs of an LOLE model. This is in contrast to a pure exceedance approach, which fails to appreciate the critical correlation risks that arise on extreme weather days. PG&E's Peak Day methodology attempts to address this by observing Peak Days within each year; however, this approach may include irrelevant observations, such as peak days occurring in a mild year, and miss relevant observations, such as an extended peak event occurring in an extreme year with more at-risk days than the subset permits. In contrast, *Worst Day* and *LOLE-Informed* approaches sample the peak days in peak years for each individual month, ignoring mild years and capturing the full range of at-risk days in extreme years.

Synthesis: Discussions of profile synthesis have raised two critical challenges for an exceedance-based methodology – the need to develop profiles which are faithful reproductions of the entire day, not an amalgamation of hourly values from a random assortment of days, and the need to develop profiles which are reasonable across both multiple months and multiple hours. In contrast, a single exceedance value may be building a profile which includes observations from certain peak days during peak hours, but observations from a fully separate range of days for morning or overnight hours, resulting in profiles which may not truly reflect performance during days of concern – either under- or over-valuing. Similarly, the use of a single exceedance value that is reasonable for critical hours *and* appropriately values off-peak hours *and* meets the same criteria across all other months is an impossible challenge[16].

In recognition of this impossible task, various parties have suggested that the use of exceedance represents an unnecessary step relative to the benchmarks. NRDC supports the elimination of the exceedance step regardless of the benchmark developed, but both the *Worst Day* and *LOLE-Informed* approaches are designed to be implemented without conversion through an exceedance process which distorts hourly and monthly performance in off-peak hours.

Illustrative Results: Using modeled data developed as part of the GridPath RA Toolkit[17], NRDC developed a comparison of exceedance profiles and the results of the *Worst Day* methodology. Results were presented by NRDC at the August 23, 2022, Resource Counting workshop[18]. These results

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[16] See, e.g., NRDC comparison of Worst Day and Exceedance Results https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_cal-advocates_221006.pdf;
CalPA Exceedance Benchmarking Results
https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_cal-advocates_221006.pdf;

[17] GridPath RA Toolkit, GridLab. https://gridlab.org/gridpathratoolkit/

[18] NRDC Resource Counting Workshop Slides, August 23, 2022 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-23-2022-planning-reserve-margin/workshop-5_nrdc_220823.pdf

illustrated the challenge of benchmarking any single exceedance value to reasonable, expected output during periods of grid stress.

Figure 7: Variation Between Exceedance and Worst Day Methodologies for Wind in the SCE TAC Area

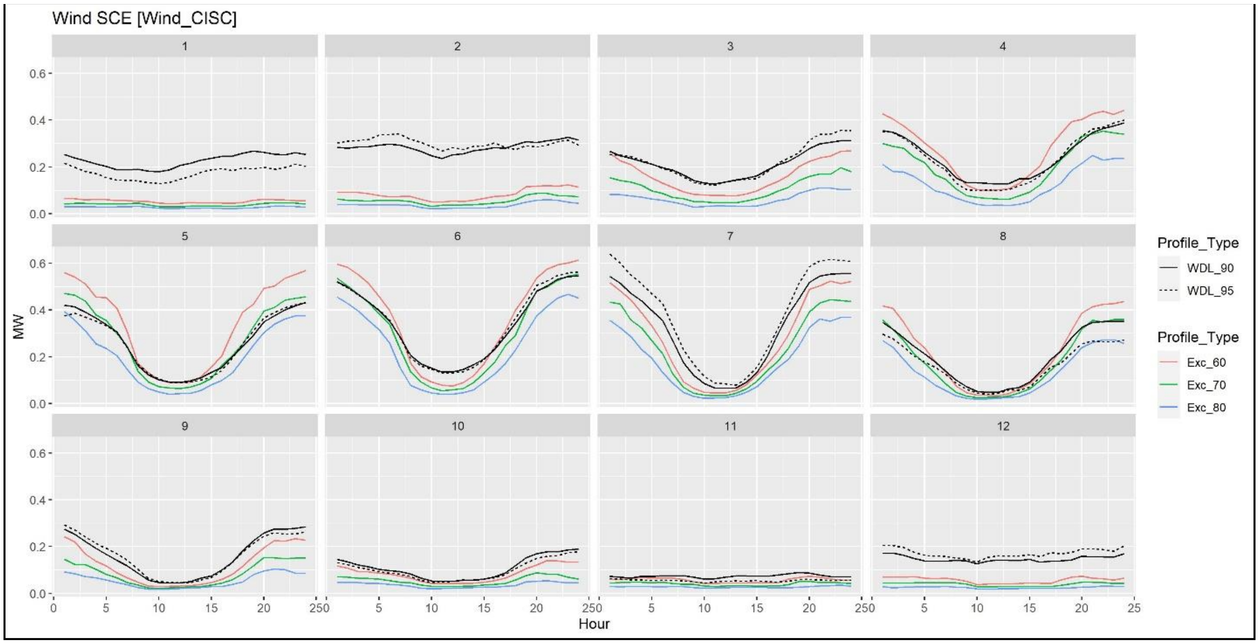


Figure 8: Variation Between Exceedance and Worst Day Methodologies for Solar in the SCE TAC Area

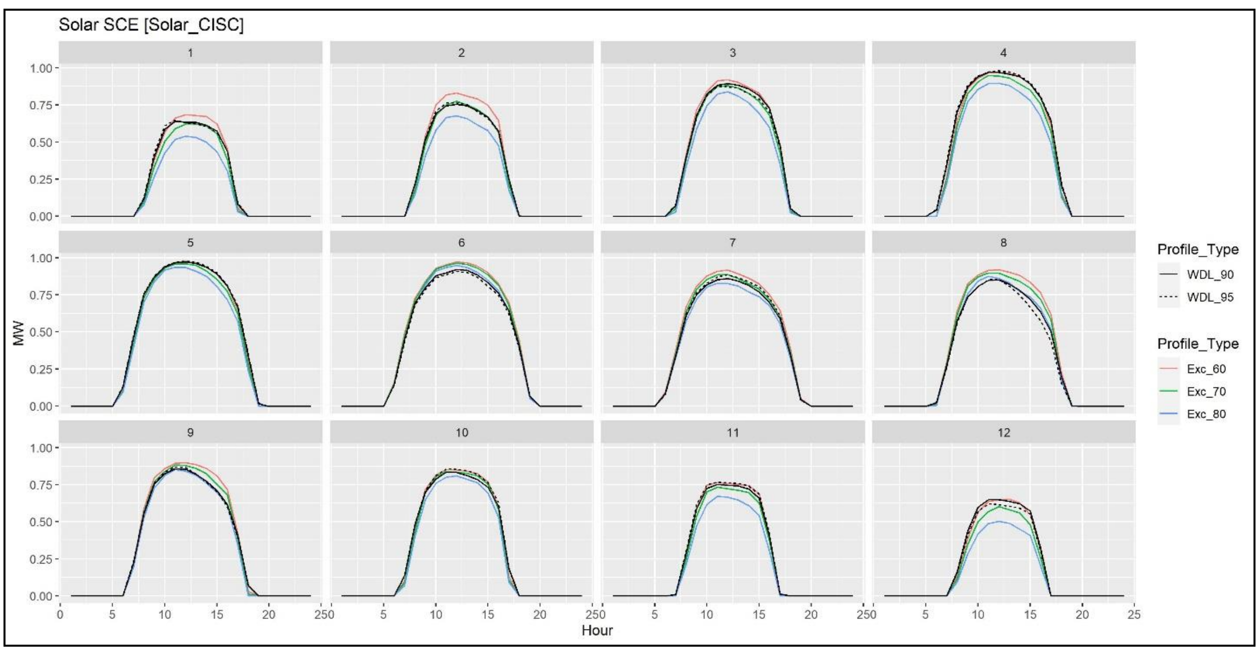


Table 3: Overview and Recommendations

	Exceedance (Peak Day)	Worst Day	LOLE-Informed
Overview	Statistical analysis of availability calibrated to align with expected production on highest load days	Profiles synthesized as average of observed "worst days" by load or net load in dataset	Profiles synthesized as weighted average of output on days experiencing LOLE events in LOLE model
Data Needs	Hourly resource dataset with demand data (modeled or historical)	Hourly resource dataset with demand data (modeled or historical)	Resource production and reliability observations output from LOLE model (modeled)
Pros	Simple and transparent to perform, incorporates correlation between resources and demand	Simple and transparent to perform, incorporates correlation between resources and demand, improves alignment of shapes relative to exceedance	Leverages robust LOLE modeling to align resource profiles with periods of reliability concerns
Cons	Exceedance values may not produce profiles that align shapes and magnitudes with peak day observations	Highest load / net load days may not always reflect reliability periods of concern, e.g. moderate load days with poor resource output	Proprietary data, limited stakeholder transparency

d. NRDC Resource Counting Selection Process Proposal

Authors: NRDC

Throughout the SOD Workshop Process, NRDC has emphasized the importance of developing program parameters which are durable to a changing resource mix and changing reliability needs; specifically, resource counting rules which minimize the introduction of 'error' which must be addressed through adjustments to the PRM. Leveraging stress testing analysis performed by ED to assess the durability of the PRM[19], NRDC has developed a method to compare the relative durability and accuracy of different resource counting rule options as the resource mix changes.

Specifically, NRDC proposes that the Commission adopt a selection process, to be implemented by Energy Division, to adopt the resource counting methodology which results in the lowest change to PRM as the portfolio evolves (Δ PRM / Δ Portfolio). This proposal builds on on-going analysis and policy discussion from NRDC illustrating that higher resource counting value is likely to result in a higher PRM, and lower resource counting value can result in a lower PRM[20]:

- ΔPRM↑ (PRM Increases If):
    - Overcount capacity in constrained hours
    - Overcount energy (excess capacity) in energy-constrained months
    - Undercount load, reserves, other contingencies
- ΔPRM↓ (PRM Decreases If):
    - Undercount capacity in constrained hours
    - Undercount energy (excess capacity) in energy-constrained months
    - Overcount load, reserves, other contingencies
- ΔPRM Ø (No Change in PRM If):
    - Error in capacity counting in unconstrained hours
    - Error in energy counting in energy unconstrained months
    - Error in load shape / magnitude in unconstrained hours

With a single calibrated portfolio from the monthly LOLE study, it was not possible to assess which resource counting rules are "correct" from the perspective of minimizing inflation or deflation of the PRM through inaccurate counting as the portfolio changes. However, stress testing analysis from Energy Division enables this 'triangulation' between resource profiles which can inform which resource counting rules introduce the least amount of error.

Specifically, NRDC's proposal to select the resource counting methodology is described in the following steps:

1. Energy Division should identify 1-2 reliable future portfolios @ 0.1 LOLE with different levels of solar and wind capacity aligned with IRP projections

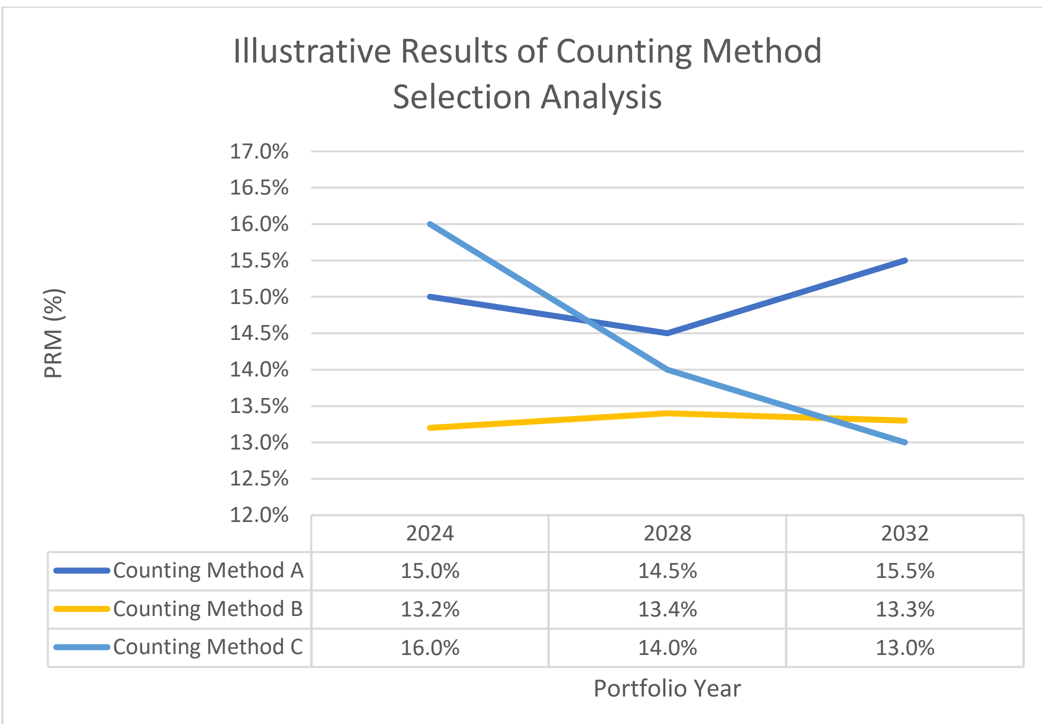
[19] Energy Division PRM Analysis Results, October 6, 2022. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_energy-division_221006.pdf

[20] NRDC Program Calibration Presentation, Slide 11, August 17, 2022. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2022-planning-reserve-margin/workshop-4_nrdc_220817.pdf

2. The portfolios should be entered into the finalized SOD Calibration tool to test the impact of different resource counting methodologies on the PRM:
    - Different resource counting rules will result in different PRMs
    - Resource profiles that overstate reliability contribution will require a higher PRM as more of the resource is added
    - Resource profiles that understate reliability contribution will require a lower PRM as more of the resource is added
3. The resource counting methodology with the smallest change to PRM as the portfolio evolves should be adopted

An illustrative approach to this counting method is demonstrated below. In this example, Energy Division performs analysis on three portfolios, representing resource plans for the years 2024, 2028, and 2032, and assesses three counting methodologies, Counting Method A, Counting Method B, and Counting Method C. As expected, the PRM changes with each portfolio change.

Figure 9: Illustrative Results of Counting Method Selection Analysis



Relative to the 2024 portfolio, Counting Method A results in a PRM decline of 0.5% in 2028 and an increase of 1.0% in 2032. Counting Method B results in a PRM increase of 0.2% in 2028 and a decline of 0.1% in 2032. Counting Method C results in a PRM decrease of 2.0% in 2028 and a decline of 1.0% in 2032. Using NRDC's selection proposal, Energy Division would adopt Counting Method B as the method which produces the most durable PRM results, implying that the counting method is consistent with the resource's reliability contribution across the changing portfolio mix.

This approach will indicate which resource counting methodology best approximates the inputs to the LOLE study on critical days.

e. CalWEA

Authors: CalWEA

Average Production on Top-5-Load Days

CalWEA proposes that wind and solar QCs be based directly on a sampling of historical wind and solar production during the top 5 highest-load days in each month, using historical CAISO data for resource production and CAISO generator interconnection capacities to normalize the data. Capturing the correlation between production and stressed grid conditions best represents the impact of wind and solar on overall grid reliability. This approach generally mimics the ELCC method, which counts capacity only if the resource production helps reduce the grid's capacity needs.

Several high-load data sampling approaches were proposed in the workshops:

- CalWEA initially proposed the Effective Net-Load Reduction (ENLR) approach for determining QC values. This method calculates a simple average of historical hourly wind or solar output during those hours of the year when load is higher than a defined threshold level. The calculation would rely on CAISO's production data from the previous three to five historical production years. A threshold load level must be selected to focus on the hours in which load is at or above a particular load level. For example, a 50% threshold load level would average wind and solar production only for the hours during which load is at 50% of maximum load or higher. This proposal used interconnection capacity to normalize the data. The resulting ENLR values were shown to be remarkably stable using load thresholds between 50% and 85%.

- PG&E proposed a method to benchmark its seasonal exceedance approach based on a sampling of CAISO wind and solar production data during stressed grid conditions. PG&E's proposal goes on to use wind and solar's performance during these high-load days to inform the selection of an exceedance level. While using high-load data sampling greatly reduces the arbitrariness of selecting an exceedance value, there is no added value in the extra step of selecting an exceedance level based on the benchmark capacity values -- it serves only to introduce some level of subjectivity (for example, whether to select 1, 2 or 12 seasonal exceedance values). Further, the added step of selecting exceedance numbers would potentially need to be revisited every year, because the choice of exceedance numbers is a judgment call that should involve stakeholders. Instead, the calculated average production from the high-load days can be used directly as the QC value.

- NRDC proposed two similar approaches.

ENLR selects a percentage of the highest-load *hours* during each month and calculates a simple average of those hourly values, while PG&E's benchmark selects the top five highest-load days in each month and calculates the average hourly production over those *five entire days*. PG&E converts average production to a capacity factor using interconnection capacity, consistent with the ENLR approach.

CalWEA compared the results of the ENLR approach, at various load thresholds, with the results of PG&E's Top-5-Load-Day benchmark approach and showed that the results are generally consistent. However, the PG&E Top-5-Load-Day approach is based on 30 datapoints for each hour in each month over a six-year dataset, while the sample size used for ENLR can be smaller or larger than 30 depending on the hourly load threshold selected for targeted sampling and the availability of hours in which load is higher than the threshold level. (The use of a high-load threshold can dramatically reduce the sample size, as some months will have only one hour that reaches the selected threshold). Given its consistent sample size, CalWEA now advocates the Top-5-Load-Day benchmark approach for determining wind and solar QC values.

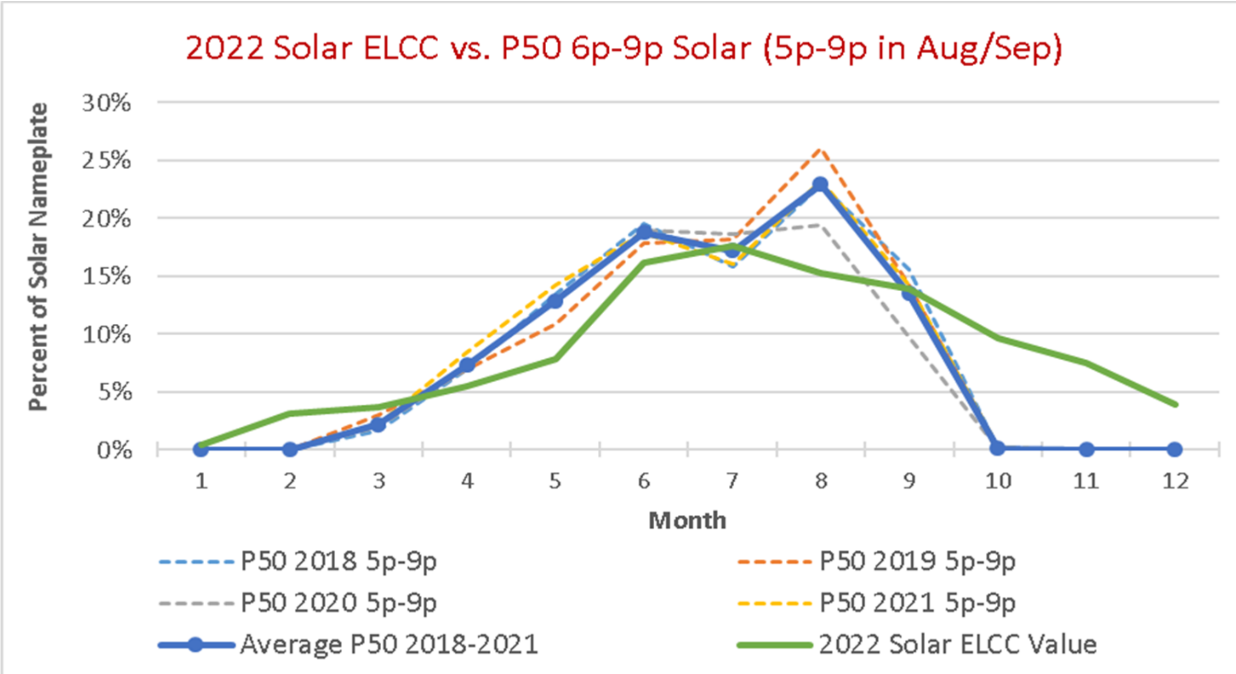
See PG&E's proposal for a more detailed description of the top-five load day methodology.

f. SEIA

Authors: SEIA

SEIA presented an updated analysis of the exceedance value for solar that could be used in implementing the Slice-of-Day reforms to the RA program. SEIA's analysis benchmarked the exceedance value against the 2023 effective load-carrying capacity (ELCC) values for the CAISO solar fleet, as adopted in D.22-06-050. In performing this benchmarking, SEIA looked at CAISO solar output in the evening hours of 6 p.m. to 9 p.m. in all months except August and September, and 5 p.m. to 9 p.m. in August and September. These are the hours with significant non-zero loss-of-load probabilities. SEIA's benchmarking showed that the use of the 50% exceedance solar output in these hours reasonably replicated the monthly 2023 ELCC values, as shown by comparing the solid blue and green lines in the figure below:

Figure 10: 2022 Solar ELCC vs. P50 6-9 PM Solar (5-9 PM in Aug/Sep)



SEIA also has reviewed in detail PG&E's proposed methodology to set the exceedance value based on solar output in the 5 peak load days each month, using 6 years of historical data (2015-2020). SEIA believes that PG&E's approach is reasonable and is more conservative than SEIA's approach in that PG&E has chosen exceedance values that result in solar output that is generally below (rather than equal to) the peak load day data. Accordingly, SEIA can support PG&E's final proposal (from Slide 2 of its Workshop 10 presentation) to use a 70% exceedance in the summer months (June-September) and 50% exceedance in the other months (October-May).

Both the SEIA and PG&E analyses have worked from publicly available CAISO data on solar generation. SEIA believes that these data are more transparent than modeled or simulated data. SEIA supports the use of as many years of historical CAISO production data as possible. SEIA would support the further disaggregation of this data by fixed vs. tracking arrays and by NP-15/SP-15, as logical further improvements to the counting rules for solar.

g. ACP of CA

Authors: ACP of CA

The American Clean Power Association of California proposes the following steps for determining the qualifying capacity for wind resources:

1. Develop a monthly generation profile for each wind region. Collect a large sample of wind production data (i.e., 4-6 years, not just the worst days). For new wind resources in areas without historic production information (e.g., offshore-wind) use a synthetic data set (e.g., SERVM, Gridlab, etc.). Adjust synthetic data for curtailment to enable comparable treatment with resources utilizing historic data.

2. Review wind performance for each region and convert to capacity factors using capacity installed at the time. Develop 12 monthly 24-hour profiles for each wind region (i.e., D.22-08-039 regions: WY, ID, NP15, SP15, WA, OR, AZ, NM and Offshore). Disaggregate regions as much as possible (e.g., WY vs ID, AZ vs NM, etc.). In the future, the regions should be disaggregated to align with adopted ELCC region and technology definitions in the RA and Integrated Resource Planning (IRP) proceedings. Average data across all years to arrive at a 24-hour MonthlyProfile for each region.

3. Test monthly exceedance values for each region on a monthly basis (See figures 1 and 2). Develop the weighted average production for each month from the historic or synthetic data.[21] The output is a single, monthly capacity factor. Test the monthly profile against monthly ELCC values developed in D.22-08-039 (in the future, align with marginal ELCCs developed in the IRP process) by applying an exceedance analysis at a selected level. Rerun the weighted average production for each month until the monthly capacity value aligns with the derate for the ELCC. Select a monthly exceedance value for each region and month where the weighted average counted production as a percentage of nameplate capacity aligns with the corresponding monthly ELCC for that same region (See Figure 3). Apply the selected exceedance threshold for that month to determine the hourly capacity factor derates for all wind resources within the region.

4. Update the analysis as new production data becomes available and updates to ELCC are available in the IRP proceeding.

Rationale:

Step 1. ACP of CA proposes a broader data set to be responsive to the CAISO's observations during the workshops concerning the need to capture a greater number of load conditions.

Step 2. There should be region-specific capacity factors to align with findings in D.22-08-039 regarding variations in relative wind capacity value between various geographic regions.

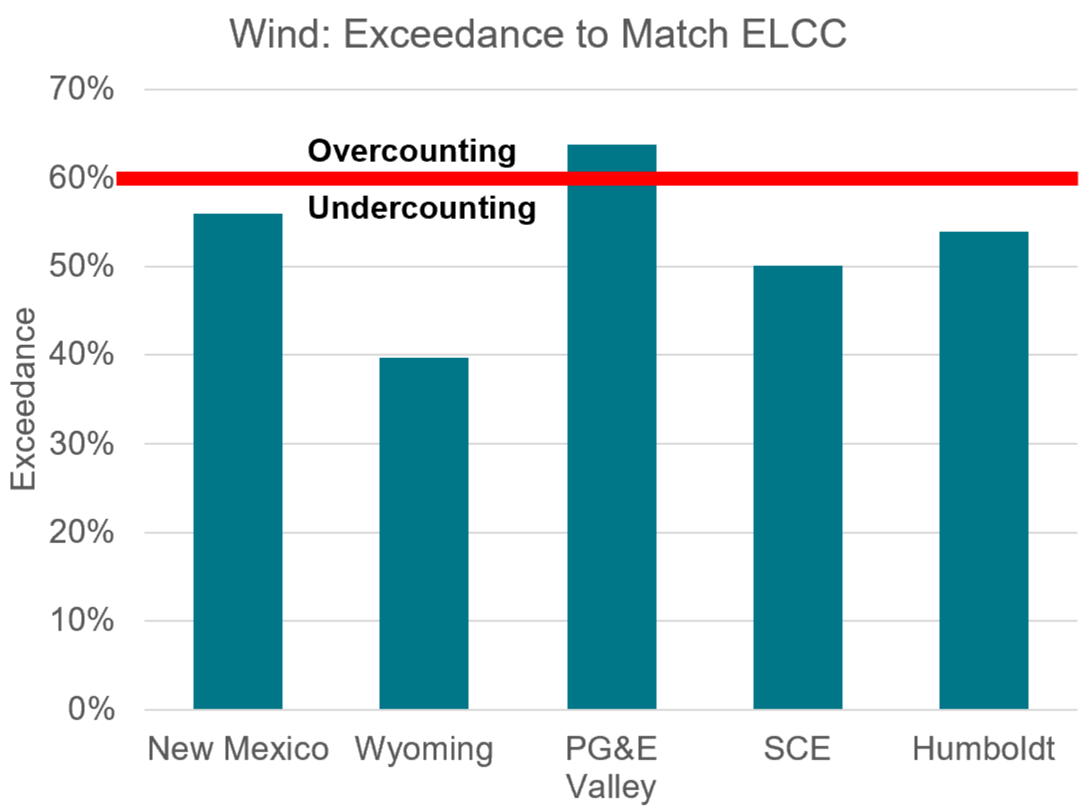
Step 3- 4. The ELCC benchmarking framework was proposed to address workshop participant concerns regarding the arbitrariness of selecting certain exceedance thresholds for wind resources and concerns that the results of exceedance differ greatly from ELCC as explained in the quantitative analysis provided by the Joint Wind Parties' workshop presentation on August 23, 2022.[22] The Joint Wind Parties analysis expressed concern that exceedance does not reflect correlation of reliability value between different resources at a system level. Since correlated reliability value is captured in an ELCC analysis, the Joint Wind Parties propose using ELCC to refine the selection of exceedance thresholds. The Joint Wind Parties generally oppose exceedance as a reliability metric for wind resources but offer this proposal to be responsive to the Commission's direction in D.2206035. By summing the generation-weighted average load for the 24-hour period and comparing that capacity factor to the ELCC, the resulting selection of a particular exceedance threshold is at least tied more closely to a broadly-accepted

[21] Please note ACP of CA remains opposed to the use of exceedance as will be explained in comments on the Workshop Report. ACP of CA offers this proposal as a methodology that helps resolve concerns regarding the arbitrariness of the selection of exceedance values and hope and tie Slice of Day framework more closely to the statutory requirements requiring an ELCC.

[22] See Joint Wind Parties Presentation (8/23/2022), available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-23-2022-planning-reserve-margin/workshop-5_pattern-acp_220823.pdf

reliability planning tool. Attempting to align reliability accounting with the ELCC would also help meet the Commission's policy goals of ensuring more consistent signals across the main procurement programs. The ELCC resource counting method is used to assign capacity values for intermittent resources across the WECC, the Eastern Interconnect, and is being used in the Western Resource Adequacy program. The ELCC is also required in the Renewable Portfolio Standard (RPS) proceeding when the IOUs apply the "least-cost best fit" tests to proposed RPS procurement. The ELCC has recently been updated in multiple iterations of RA and IRP proceedings and may play an important role in future IRP procurement, including compliance with IRP reliability targets.

Figure 11: Over / Under Counting Exceedance values



Using Exceedance of 60% over values PG&E Valley compared to ELCC. The Qualified Capacity is higher than under the ELCC.

Figure 12: Comparison of Monthly Exceedance and ELCC values

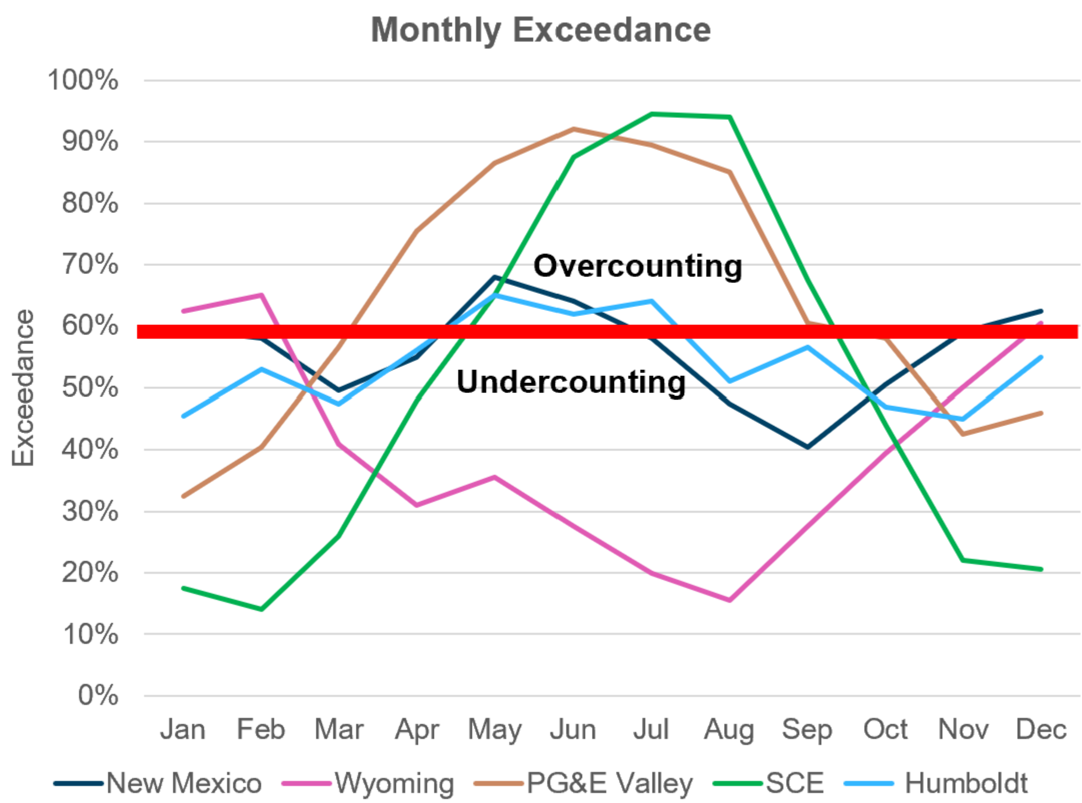


Figure 12 shows how exceedance values vary significantly throughout the year when aligned with the monthly ELCCs. In Figure 12, the Joint Wind Parties used a full sample of data (GridLab) to build representative distributions for exceedance percentiles.

Table 4: Results of using ELCC to select a monthly exceedance value by wind region

Month	New Mexico	Wyoming	PG&E Valley	SCE	Humboldt Offshore
Jan	60%	63%	33%	18%	46%
Feb	58%	65%	41%	14%	53%
Mar	50%	41%	57%	26%	48%

Apr	55%	31%	76%	48%	56%
May	68%	36%	87%	65%	65%
Jun	64%	28%	92%	88%	62%
Jul	58%	20%	90%	95%	64%
Aug	48%	16%	85%	94%	51%
Sep	41%	28%	61%	68%	57%
Oct	51%	40%	58%	44%	47%
Nov	59%	50%	43%	22%	45%
Dec	63%	61%	46%	21%	55%

h. CalPA

Authors: CalPA

Summary

Cal Advocates proposes setting four quarterly exceedance values for wind resources, benchmarked against the Average Top 5 Worst Day historical production, and calculated regionally. Quarterly exceedance values should be calculated by minimizing the sum of absolute value of the within-quarter difference between the benchmark load profile and the historical capacity factor identified by a given exceedance value. This proposal uses a minimization routine to iterate exceedance values until identifying the value with the least variation.

Proposal

a. Regions

Cal Advocates proposes calculating quarterly exceedance values for wind resources using the six existing wind regions that were used to calculate ELCC values for wind resources in R.21-10-002.[23]

- Northern California (NP15)
- Southern California (SP15)
- Northeast Out of State (OOS) Wind (Wyoming/Idaho)
- Northwest OOS Wind (Washington/Oregon)
- Southwest OOS Wind (Arizona/New Mexico)
- Offshore Wind

[23] *Administrative Law Judge's Ruling on Energy Division's Regional Wind Effective Load Carrying Capability Study*, June 1, 2022, Appendix A, pp. 2-3.

Calculating exceedance values for each region ensures that lower-performing wind regions do not otherwise penalize the resource adequacy (RA) value of all resources for each technology type. As more wind resources serve load in California and develop a longer historical record of performance, this proposal can be amended to calculate exceedance values at higher regional granularities.

b. Data Sources and inputs

This proposal was developed using PG&E's July 27, 2022, dataset,[24] which compiled data on hourly wind and solar performance for the years 2015-2020. The wind resource raw data is provided on the *Source_Data_regional* tab. Each row on this tab represents one hour of data for a wind-producing region in California (either NP15 or SP15). The tab includes columns for Date, Region (e.g., NP15, SP15), Year, Month, Day, Hour, Capacity Factor of wind resources in that region (normalized by the regional installed capacity of wind resources at that time). Expanding this dataset to apply to other regions would require the same information.

c. Selecting a benchmark profile

Cal Advocates proposal builds on PG&E's Top 5 Worst Day Approach and replicates the first three steps employed by PG&E to identify a benchmark load profile consisting of the month-hour average of the wind performance observed on the Top 5 Worst Days:[25]

1. Identify the top 5 peak load days in each month during the historical period.[26]

2. Review solar and wind performance during those days and convert to capacity factors using installed capacity at the time.

3. Average data across all years to arrive at a peak load day profile.

Utilizing a generation profile that is benchmarked by constraining it to wind resource performance on a certain number of high-load days is intended to be a conservative resource counting assumption. However, while the correlation between solar resources and electric load is generally strong, the correlation between wind and load is much weaker. Therefore, this assumption is itself weaker. Nonetheless, Cal Advocates concurs with PG&E that utilizing the Top 5 Worst Day Approach is an appropriate (if imperfect) hedge against some degree of variability in wind performance. Using the Top 5 Worst Day Approach leads to relatively more conservative values for wind, though this would capture generation uncertainty that may otherwise be allocated to the Planning Reserve Margin (PRM) if a Loss of Load Expectation study is used to set the PRM.

d. Calculating exceedance levels

Cal Advocates' proposal uses the following steps to calculate quarterly exceedance values for each wind region, and starts with the PG&E July 27, 2022, dataset on the *Wind_Comparison* tab:

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[24] *RA Reform - PGE - Exceedance Analysis - 2022-07-27 Workshop.xlsx.* Available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-history

[25] PG&E, *Resource Counting: Solar and Wind*, July 27, 2022, p. 5.

[26] This proposal uses 2015-2020 as the historical period. We recommend future studies use the last 5 years of complete historical wind production data.

1. Adapt the cells in PG&E's "Average Worst Days Vs. Exceedance" table to call on a quarterly exceedance value rather than a single annual exceedance value.

Figure 13: Average Worst Days Vs. Exceedance Updated

Quarterly exceedance values

Table 2: Average Worst Days Vs. Exceedance

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Sum	Sum(Abs)	Max
	1 Jan				-4%	-4%	-3%	-3%	-2%	-2%	-2%	-2%	-2%	-3%	-5%	-7%	-6%	-5%	-5%	-5%	-7%	-5%	-3%	-2%	-1%			
32%	2 Feb				-8%	-5%	-5%	-6%	-6%	-8%	-8%	-10%	-9%	-9%	-2%	-1%	-1%	2%	-3%	-3%	0%	0%	2%	3%	3%	-85%	249%	8%
	3 Mar	7%	8%	8%	6%	2%	2%	4%	5%	3%	1%	1%	2%	2%	2%	2%	3%	2%	4%	3%	1%	0%	-1%	-1%	1%			
	4 Apr	-8%	-8%	-8%	-10%	-11%	-8%	-8%	-7%	-9%	-6%	-5%	-5%	-4%	-3%	-5%	-5%	-2%	-3%	-7%	-7%	-4%	-8%	-8%	-14%			
57%	5 May	2%	0%	-1%	-1%	-2%	-4%	-4%	-2%	-2%	-4%	-5%	-5%	-3%	1%	-1%	0%	5%	6%	4%	3%	-3%	-1%	-4%	-5%	-100%	316%	7%
	6 Jun	4%	4%	4%	6%	5%	3%	1%	5%	2%	2%	2%	2%	2%	2%	3%	5%	7%	7%	5%	4%	3%	1%	3%	2%			
	7 Jul	4%	2%	4%	4%	6%	6%	4%	3%	1%	1%	0%	0%	-1%	-2%	-1%	-2%	3%	4%	5%	7%	7%	7%	5%	4%			
62%	8 Aug	15%	14%	11%	10%	10%	9%	8%	7%	4%	2%	0%	0%	-2%	1%	1%	4%	7%	8%	8%	9%	9%	9%	9%	9%	67%	418%	15%
	9 Sep	0%	-1%	-3%	-3%	-6%	-6%	-8%	-8%	-7%	-6%	-6%	-6%	-5%	-5%	-6%	-7%	-7%	-10%	-8%	-9%	-10%	-11%	-15%	-12%			
	10 Oct	8%	7%	5%	3%	1%	-1%	-1%	0%	-1%	-1%	0%	-1%	-1%	-1%	0%	1%	3%	6%	7%	8%	9%	9%	5%	5%			
38%	11 Nov	1%	2%	4%	3%	3%	4%	4%	4%	2%	2%	1%	2%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-1%	-1%	-1%	-2%	-3%	-31%	251%	9%
	12 Dec	-6%	-5%	-7%	-6%	-6%	-7%	-8%	-6%	-6%	-7%	-6%	-8%	-9%	-8%	-7%	-6%	-4%	-3%	-2%	-1%	-1%	0%	0%	0%			
																		MIN	-15.3%	MAX	14.7%	AVG	-0.52%	SD	0.0526			

2. Add a table ("Average Worst Days Vs. Exceedance: CAPACITY FACTORS") which displays the month-hour capacity factors that result from a given quarterly exceedance value. Each cell represents the month-hour pair sum of the corresponding cells in PG&E's tables 1 and 2.

Figure 14: Average Worst Days Vs. Exceedance: CAPACITY FACTORS

Table 3: Average Worst Days Vs. Exceedance: CAPACITY FACTORS

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Mo Avg	Qtr Avg
1 Jan	12%	11%	9%	9%	10%	10%	11%	12%	11%	8%	7%	7%	7%	7%	6%	7%	7%	9%	9%	10%	10%	10%	11%	12%	9%	
2 Feb	26%	27%	24%	19%	20%	19%	19%	20%	19%	19%	17%	18%	15%	20%	22%	20%	17%	14%	15%	20%	20%	23%	24%	25%	20%	17%
3 Mar	26%	25%	24%	23%	20%	18%	19%	19%	16%	15%	16%	15%	15%	19%	21%	21%	24%	27%	27%	26%	28%	27%	27%	28%	22%	
4 Apr	31%	31%	28%	25%	21%	20%	17%	16%	11%	12%	11%	9%	9%	10%	10%	13%	20%	23%	21%	24%	31%	30%	33%	31%	20%	
5 May	54%	51%	49%	47%	42%	37%	32%	29%	27%	23%	18%	15%	16%	21%	22%	30%	39%	46%	46%	50%	51%	54%	54%	53%	38%	34%
6 Jun	63%	63%	60%	59%	54%	48%	42%	39%	31%	25%	21%	17%	16%	17%	22%	32%	43%	50%	51%	55%	58%	59%	62%	64%	44%	
7 Jul	69%	66%	66%	63%	61%	57%	53%	47%	37%	30%	23%	19%	18%	19%	25%	32%	43%	50%	54%	59%	63%	66%	68%	70%	48%	
8 Aug	71%	69%	65%	61%	59%	54%	48%	41%	31%	25%	19%	16%	14%	16%	20%	28%	38%	44%	48%	55%	62%	67%	70%	70%	46%	38%
9 Sep	40%	37%	34%	31%	25%	24%	19%	17%	15%	12%	8%	5%	5%	5%	6%	9%	12%	15%	21%	26%	31%	33%	32%	35%	21%	
10 Oct	28%	28%	26%	23%	20%	17%	14%	14%	12%	11%	13%	12%	10%	11%	11%	11%	13%	16%	20%	24%	29%	31%	30%	30%	19%	
11 Nov	12%	13%	12%	10%	9%	9%	8%	8%	6%	5%	5%	5%	4%	4%	5%	5%	5%	5%	7%	7%	9%	10%	12%	12%	8%	12%
12 Dec	13%	13%	12%	11%	11%	10%	11%	10%	9%	9%	9%	7%	7%	7%	7%	6%	7%	8%	9%	10%	11%	12%	13%	13%	10%	
																									25.4%	

3. Add a table ("Absolute Value of Difference") whose cells represent the absolute value of the corresponding month-hour cell in Figure 13.

Figure 15: Absolute Value of Difference

Table 4: Absolute Value of difference

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1 Jan	1%	0%	3%	4%	4%	3%	3%	2%	2%	2%	2%	2%	3%	5%	7%	6%	5%	5%	5%	7%	5%	3%	2%	1%
2 Feb	1%	1%	3%	8%	5%	5%	6%	6%	8%	8%	10%	9%	9%	2%	1%	1%	2%	3%	3%	0%	0%	2%	3%	3%
3 Mar	7%	8%	8%	6%	2%	2%	4%	5%	3%	1%	1%	2%	2%	2%	2%	3%	2%	4%	3%	1%	0%	1%	1%	1%
4 Apr	8%	8%	8%	10%	11%	8%	8%	7%	9%	6%	5%	5%	4%	3%	5%	5%	2%	3%	7%	7%	4%	8%	8%	14%
5 May	2%	0%	1%	1%	2%	4%	4%	2%	2%	4%	5%	5%	3%	1%	1%	0%	5%	6%	4%	3%	3%	1%	4%	5%
6 Jun	4%	4%	4%	6%	5%	3%	1%	5%	2%	2%	2%	2%	2%	2%	3%	5%	7%	7%	5%	4%	3%	1%	3%	2%
7 Jul	4%	2%	4%	4%	6%	6%	4%	3%	1%	1%	0%	0%	1%	2%	1%	2%	3%	4%	5%	7%	7%	7%	5%	4%
8 Aug	15%	14%	11%	10%	10%	9%	8%	7%	4%	2%	0%	0%	2%	1%	1%	4%	7%	8%	8%	9%	9%	9%	9%	9%
9 Sep	0%	1%	3%	3%	6%	6%	8%	8%	7%	6%	6%	6%	5%	5%	6%	7%	7%	10%	8%	9%	10%	11%	15%	12%
10 Oct	8%	7%	5%	3%	1%	1%	1%	0%	1%	1%	0%	1%	1%	1%	0%	1%	3%	6%	7%	8%	9%	9%	5%	5%
11 Nov	1%	2%	4%	3%	3%	4%	4%	4%	2%	2%	1%	2%	1%	1%	1%	1%	1%	2%	2%	1%	1%	1%	2%	3%
12 Dec	6%	5%	7%	6%	6%	7%	8%	6%	6%	7%	6%	8%	9%	8%	7%	6%	4%	3%	2%	1%	1%	0%	0%	0%

4. Add cells next to the table in Figure 13 that show the quarterly sum of the absolute value of differences shown in Figure 15.

Figure 16: Table Including the Absolute Value of Differences

Table 2: Average Worst Days Vs. Exceedance

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Sum	Sum(Abs)	Max
	1 Jan	1%	0%	-3%	-4%	-4%	-3%	-3%	-2%	-2%	-2%	-2%	-2%	-3%	-5%	-7%	-6%	-5%	-5%	-5%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			
32%	2 Feb	1%	-1%	-3%	-8%	-5%	-5%	-6%	-6%	-8%	-8%	-10%	-9%	-9%	-2%	-1%	-1%	2%	-3%	-3%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	-85%	249%	8%
	3 Mar	7%	8%	8%	6%	2%	2%	4%	5%	3%	1%	1%	2%	2%	2%	2%	3%	2%	4%	3%	1%	0%	-1%	-1%	1%			
	4 Apr	-8%	-8%	-8%	-10%	-11%	-8%	-8%	-7%	-9%	-6%	-5%	-5%	-4%	-3%	-5%	-5%	-2%	-3%	-7%	-7%	-4%	-8%	-8%	-14%			
57%	5 May	2%	0%	-1%	-1%	-2%	-4%	-4%	-2%	-2%	-4%	-5%	-5%	-3%	1%	-1%	0%	5%	6%	4%	3%	-3%	-1%	-4%	-5%	-100%	316%	7%
	6 Jun	4%	4%	4%	6%	5%	3%	1%	5%	2%	2%	2%	2%	2%	2%	3%	5%	7%	7%	5%	4%	3%	1%	3%	2%			
	7 Jul	4%	2%	4%	4%	6%	6%	4%	3%	1%	1%	0%	0%	-1%	-2%	-1%	-2%	3%	4%	5%	7%	7%	7%	5%	4%			
62%	8 Aug	15%	14%	11%	10%	10%	9%	8%	7%	4%	2%	0%	0%	-2%	1%	1%	4%	7%	8%	8%	9%	9%	9%	9%	9%	67%	418%	15%
	9 Sep	0%	-1%	-3%	-3%	-6%	-6%	-8%	-8%	-7%	-6%	-6%	-6%	-5%	-5%	-6%	-7%	-7%	-10%	-8%	-9%	-10%	-11%	-15%	-12%			
	10 Oct	8%	7%	5%	3%	1%	-1%	-1%	0%	-1%	-1%	0%	-1%	-1%	-1%	0%	1%	3%	6%	7%	8%	9%	9%	5%	5%			
38%	11 Nov	1%	2%	4%	3%	3%	4%	4%	4%	2%	2%	1%	2%	-1%	-1%	-1%	-1%	-1%	-2%	-2%	-1%	-1%	-1%	-2%	-3%	-31%	251%	9%
	12 Dec	-6%	-5%	-7%	-6%	-6%	-7%	-8%	-6%	-6%	-7%	-6%	-8%	-9%	-8%	-7%	-6%	-4%	-3%	-2%	-1%	-1%	0%	0%	0%			

MIN -15.3% MAX 14.7% AVG -0.52% SD 0.0526

Sum of the absolute values of the differences in Table 2

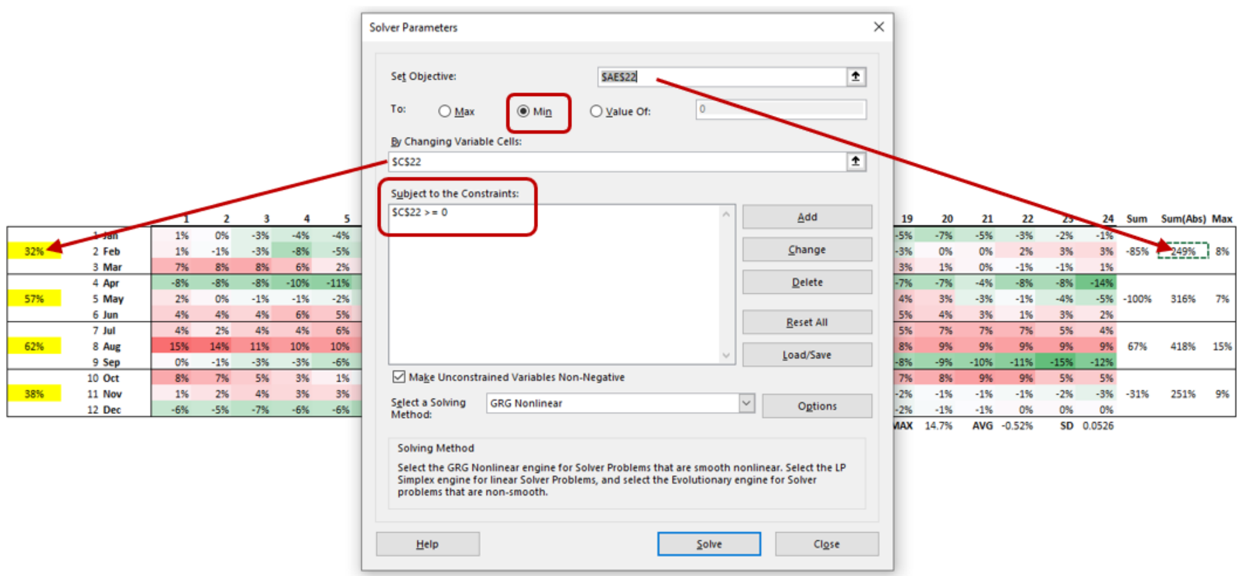
5. Use Excel Solver for each quarter to:

i. Minimize the value of the quarterly sum of the absolute value of the difference.

ii. By changing the value of the quarterly exceedance value.

iii. Subject to the constraint that the quarterly exceedance value is greater than or equal to 0.

Figure 17: Solver Demonstration



6. Interpreting the results: the Solver solution will show in the quarterly exceedance values next to the table in Figure 13. The values now shown in Figure 14 represent the month-hour capacity factors (identified by the corresponding exceedance value) that will be used to set the NQC of wind resources in the applicable region.

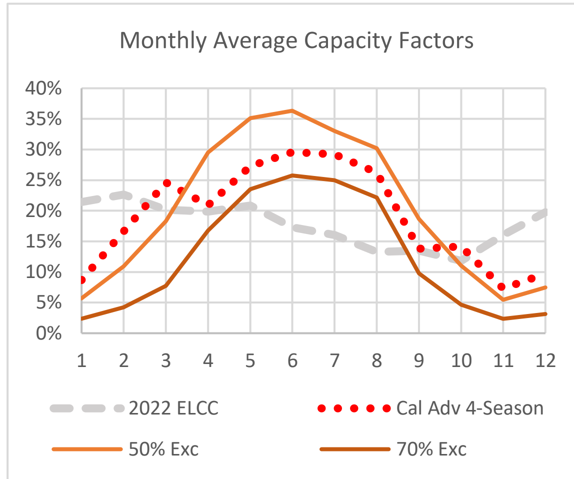
e. Exceedance Results

Cal Advocates' proposal is focused on providing a robust methodology for analytically identifying appropriate wind exceedance values while also reducing the impact of arbitrary choices. Given the currently available historical data, Cal Advocates' proposal identifies exceedance values that are shown in Table 5 below, along with the corresponding average monthly capacity factors. The graph next to Table 5, Figure 18, illustrates the average monthly capacity factors next to those identified by 50% and 70% exceedance profiles for reference, and the 2022 ELCC wind factors.

Table 5: Exceedance levels of the Four-Season Proposal

Month	Quarterly Exc. Value	Corresponding Monthly Capacity Factor
1	32%	9%
2		17%
3		25%
4	57%	21%
5		27%
6		30%
7	62%	29%
8		26%
9		14%
10	38%	14%
11		7%
12		10%

Figure 18: Monthly Average Capacity Factors



f. How to count resources in a new region

The Commission will need to calculate exceedance values for wind resources in new regions which have not yet had wind resources installed (e.g., offshore wind). This can be accomplished using modeled data on wind performance for a minimum of three years and maximum of five years to populate the dataset. As resources in new regions generate actual historical performance data, the newly collected historical data should be added to the dataset, displacing earlier years.

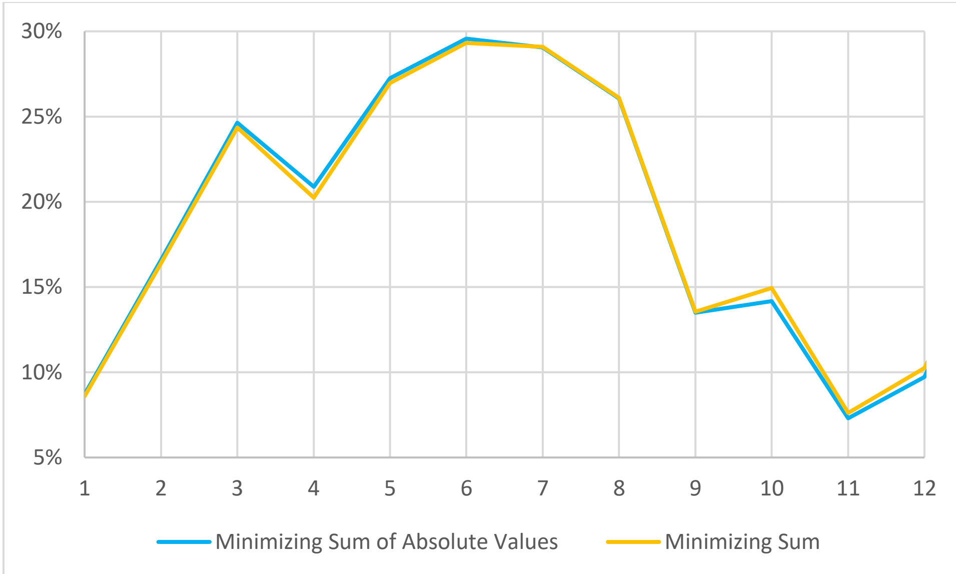
Appendix to CalPA Approach

Cal Advocates' proposal offers a few adaptations that could change how exceedance values are calculated. Each adaptation comes with its own tradeoffs between benefits and costs.

1. Simplification: Removing the absolute value step

Figure 15 in Cal Advocates' proposal shows the absolute value of the differences between the observed average capacity factor for the Top 5 Worst Days in each month-hour pair (i.e., the absolute value of each cell in Figure 13). Using the sum of the absolute value of the differences in Figure 13 rather than the sum of the differences in Figure 13 mitigates the influence of large outlier differences, with a similar effect to applying a mean squared error approach. Figure 19 illustrates the very minimal differences in capacity factors identified by Cal Advocates' proposal using the capacity factors (weighted by installed capacity in NP15 and SP15) that emerge from either minimizing the sum of the absolute value of differences (blue line) or the sum of the differences (yellow line). The difference in aggregate average capacity factor is 0.003 percentage points.

Figure 19: Weighted Capacity Factors: Absolute Value vs. Sum

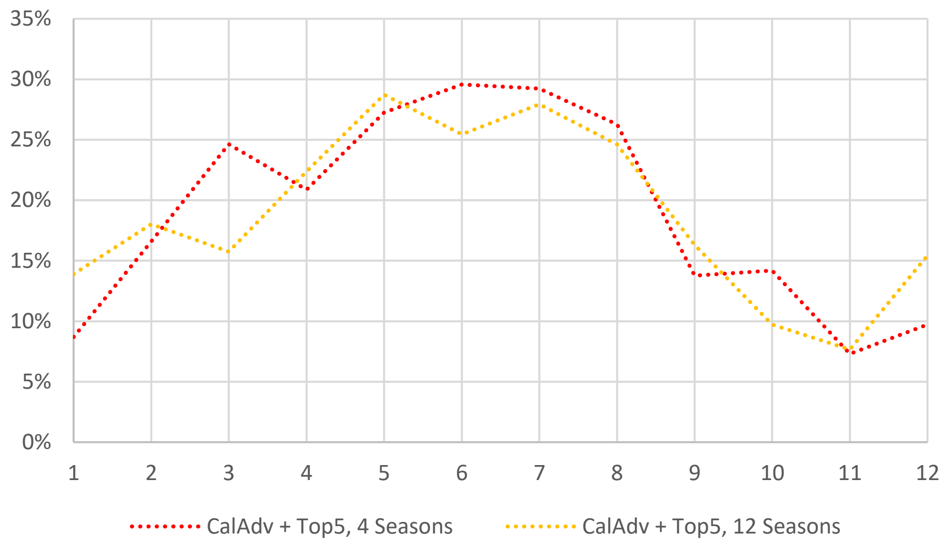


2. Enhancement: Twelve "Seasons"

This proposal could be modified to set exceedance values with a monthly rather than quarterly granularity. The same general steps outlined above apply, but instead of setting exceedance values and aggregating differences across quarters, it is done within months. Using a monthly approach would reduce the total difference between the Average Top 5 Worst Day performance and the capacity factors identified by an exceedance value.

Figure 20 shows the capacity-weighted capacity factors for California wind resources for the four-season approach (in red) and the twelve-season approach (in yellow). The biggest divergences occur in January and March, in large part because the quarterly optimization method allows overestimates in one month to potentially "subsidize" underestimates in other months. Across all months, the average capacity factor for the twelve-season approach is 18.8% while the equivalent measure for the four-season approach is 19.0%, indicating that the results from the twelve-season approach are marginally more conservative in their capacity counting.

Figure 20: California Wind Capacity Factors for 4 vs. 12 Seasons



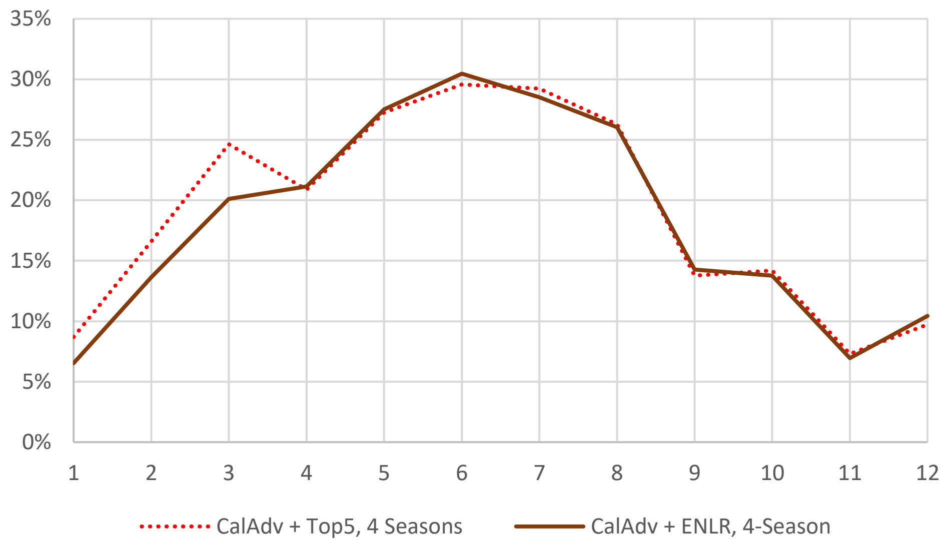
3. Variation: Using ENLR to select a benchmark profile

This proposal can be adapted to utilize the California Wind Energy Association's (CalWEA) Effective Net Load Reduction (ENLR) as a benchmark profile instead of the Top 5 Worst Day approach. The ENLR methodology works by averaging wind performance during a sample of hours above a defined percentile threshold.[27] CalWEA suggested 20% as a potential sampling threshold. Figure 21 shows the capacity factors that result from applying Cal Advocates' quarterly season approach to an ENLR Top 20% benchmark. The results largely track with the Top 5 Worst Day approach, except in the first quarter, when the ENLR approach yields lower capacity factors.[28]

[27] See CalWEA's presentations at the workshops on July 27, 2022; August 4, 2022; and October 6, 2022.

[28] This difference is largely an artifact derived from how the minimization routine balances differences across the first quarter months. When applying Cal Advocates twelve-season approach to the Top 20% ENLR benchmark (average annual capacity factor of 18.6%), the results are nearly identical the results of applying it to the Top 5 Worst Day Approach (average annual capacity factor of 18.8%).

Figure 21: Four-Season approach using Top 5 vs. ENLR

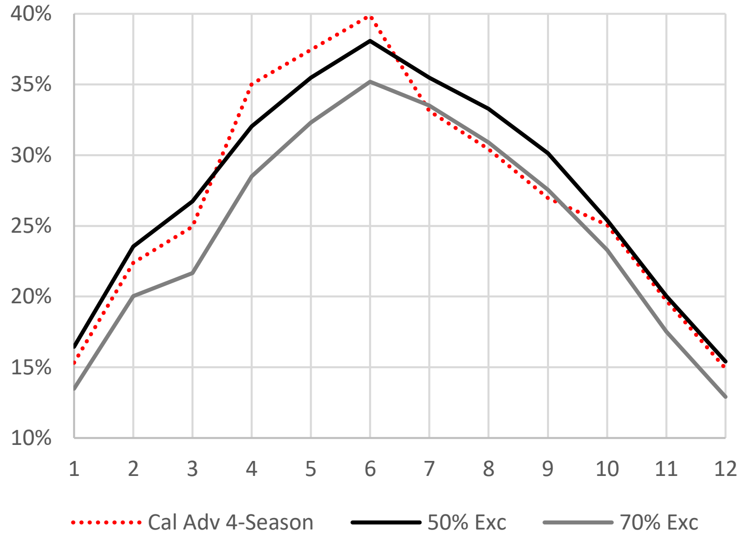


The biggest difference between the ENLR approach to sampling and the Top 5 Worst day approach is that ENLR creates a unique sample based on load in each month-hour pairing, while the Top 5 Worst Day approach identifies the Top 5 gross peaks and then utilizes the entire daily load profile for each of those days to populate the rest of the hourly slices. The ENLR approach implicitly assumes that load performance within each hour is correlated with load independent of performance in all other hours, while the Top 5 Worst Day approach assumes that performance on peak days is correlated with load throughout all hours of a peak load day.

4. Extension: Application to Solar Counting

Cal Advocates' proposal can also be extended to setting a solar exceedance level. Figure 22 shows the average monthly capacity factors identified using the four-season approach based on the same sample of six years of data and benchmarking against a Top 5 Worst Day profile; it also shows the 50% and 70% solar exceedance values for reference.

Figure 22: Four-Season Exceedance for Solar



i. CAISO

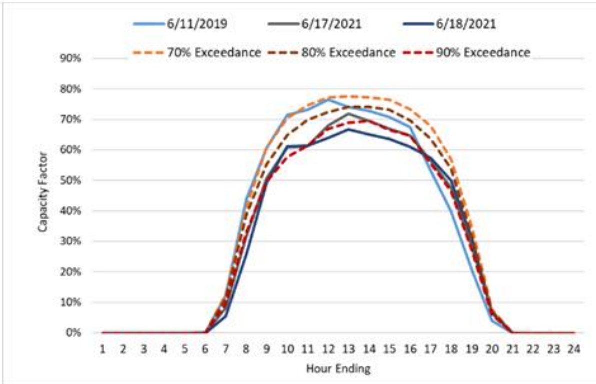
Authors: CAISO

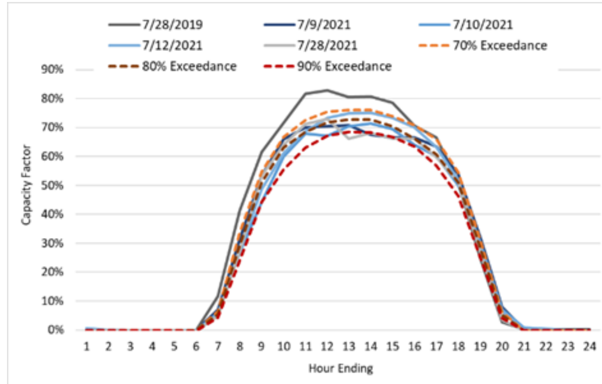
At the 10/6 workshop, the CAISO presented analysis and discussion on resource counting for solar and wind, as well as PRM issues. The CAISO performed analysis to test 70%, 80%, and 90% exceedance profiles by comparing them to actual production of solar and wind on days where the CAISO issued a Flex Alert or emergency declaration (referred to as "stressed days").

The CAISO's analysis, which covered 2020 to September 2022, showed there are many stressed days where 70% exceedance profiles did not cover solar and/or wind actual production. On several of these days, even 90% exceedance profiles did not cover actual production across all evening hours. The CAISO also noted that PG&E's top five-day benchmarking methodology did not cover all stressed days in heat waves in August 2020 and September 2022 which lasted longer than five days. Additionally, not all CAISO stressed days fell within PG&E's top five load days.

Figure 23: Solar stressed day production compared to 70%, 80%, 90% exceedance levels

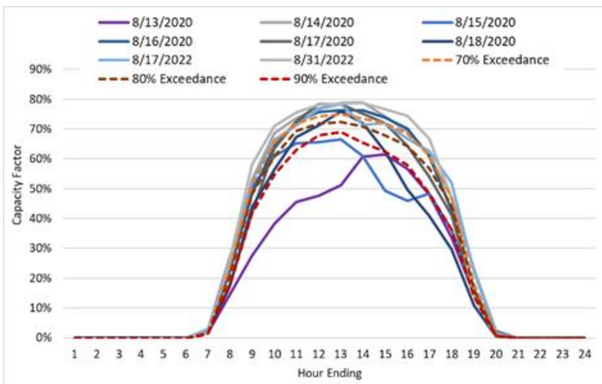
June July





August

September



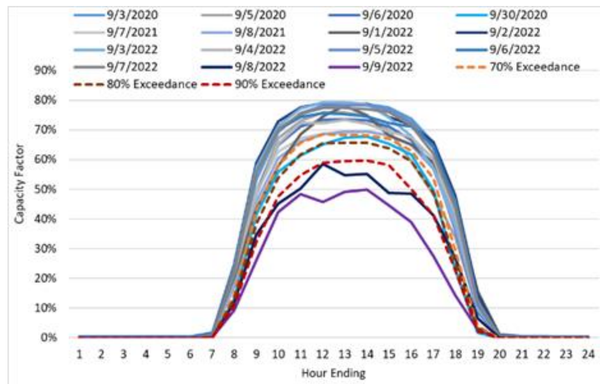
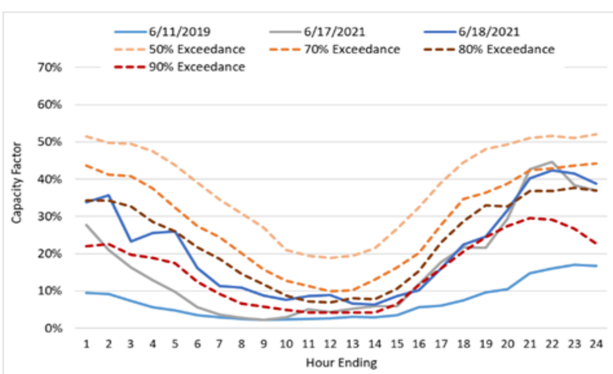
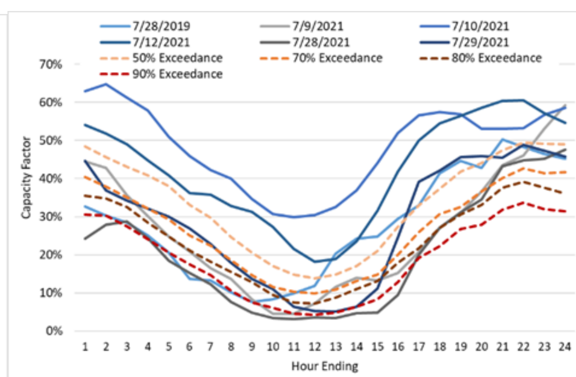


Figure 24: Wind stressed day production compared to 70%, 80%, 90% exceedance levels

June

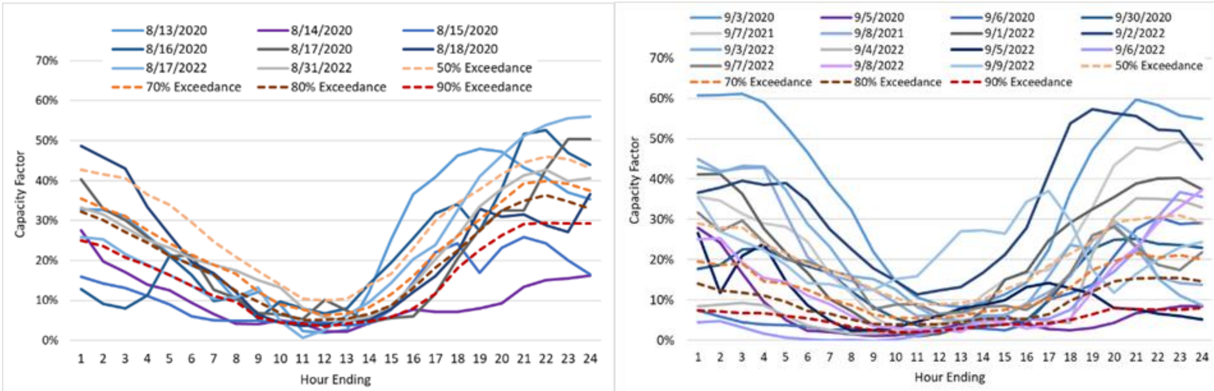
July





August

September



The CAISO also presented information on intra-month and intra-hour issues for solar resources. There is a notable decrease in hour 19 production between the beginning of August and the end of August as the sun starts to set earlier in the day. The CAISO noted that a monthly exceedance curve averages across the month and overestimates solar capabilities at the end of August. In addition, the steep decline of solar production across the sunset hours results in large decreases in solar capacity factors between 5-8 p.m. The CAISO noted that an exceedance curve at hourly granularity effectively averages across each hour and overestimates solar capabilities at the end of the hour as the sun sets.

Figure 25: Hour ending 19 solar production for all August days (2019-2022)

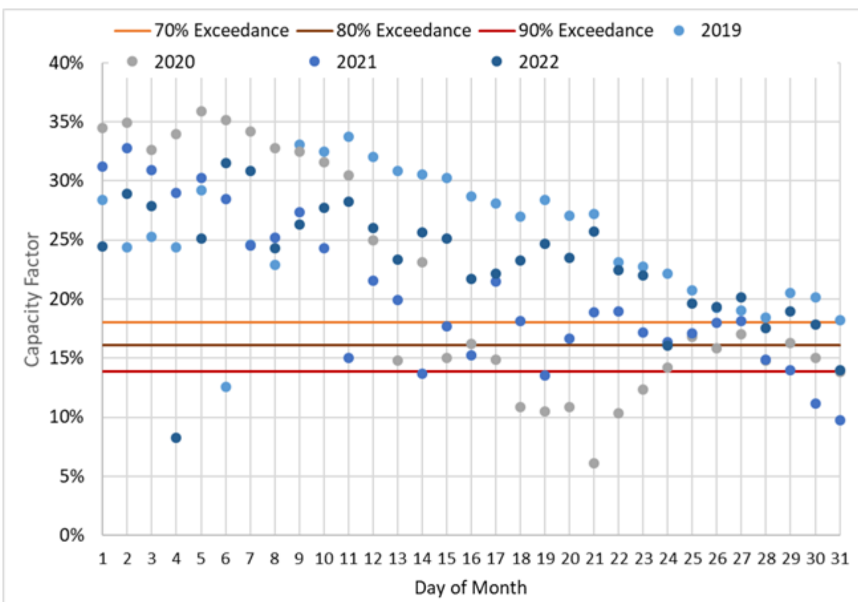
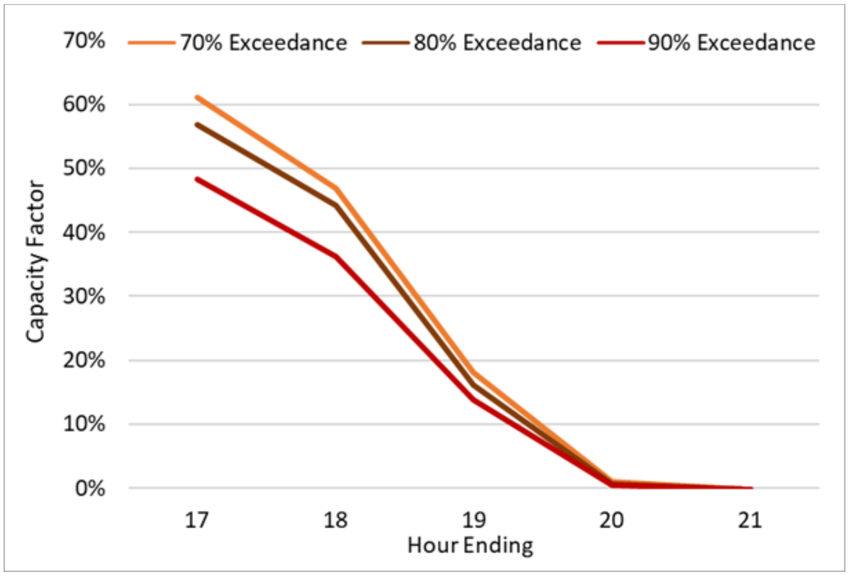


Figure 26: August HE 17 to HE 21 solar production (2019-2022)



The CAISO found these factors provide support for more conservative counting than 70% exceedance. The CAISO also noted that more conservative counting better ensures sufficient energy to charge storage resources, which will become increasingly important as storage capacity grows on the system. The CAISO stressed that if risks associated with low wind or solar production are not accounted for in resource counting, then these risks should be accounted for elsewhere, such as in the PRM as discussed below.

The CAISO recognized, as noted by several other parties, that there is a direct relationship between resource counting and the PRM, given the same resource portfolio. Using NRDC's PRM calibration tool, the CAISO showed that lower exceedance levels should translate to higher PRMs:

Table 6: Exceedance Level Impact on PRM

Exceedance Change	PRM Delta	PRM MW Delta
90% → 80%	+1.7%	+850 MW
80% → 70%	+1.5%	+800 MW

The CAISO noted that selecting a more conservative resource counting methodology can offset the risk that the direct relationship between the PRM and resource counting may be dampened in practice. For example, although lower exceedance levels will require higher PRM levels to meet reliability targets the CPUC may face regulatory challenges to set higher PRM levels.

j. MRP

Authors: MRP

MRP supports PG&E's benchmarking methodology in order to find the appropriate exceedance threshold level. MRP disagrees with PG&E on the number of days included for each month for calculating the benchmark. Instead of the Top 5 days, as PG&E proposed, MRP reviewed the 2015-2020 data and believes the top days in which the peak fall within the top 5% of hours should be used. This incorporates additional days in the benchmark as load varies over time and therefore the generation profiles developed provide additional confidence of how a resource may perform to meet the stress days that have peaks at the top 5% of hours of the month. Using this top 5% metric, MRP calculated the days within each month would range from 6 to 19 days per year. This provides a more robust dataset for benchmarking purposes.

Additional discussion of MRP's proposal using PG&E's methodology and the conclusions are detailed in the MRP's proposal package section.

V. Comparison of the proposals

Authors: Cal Advocates

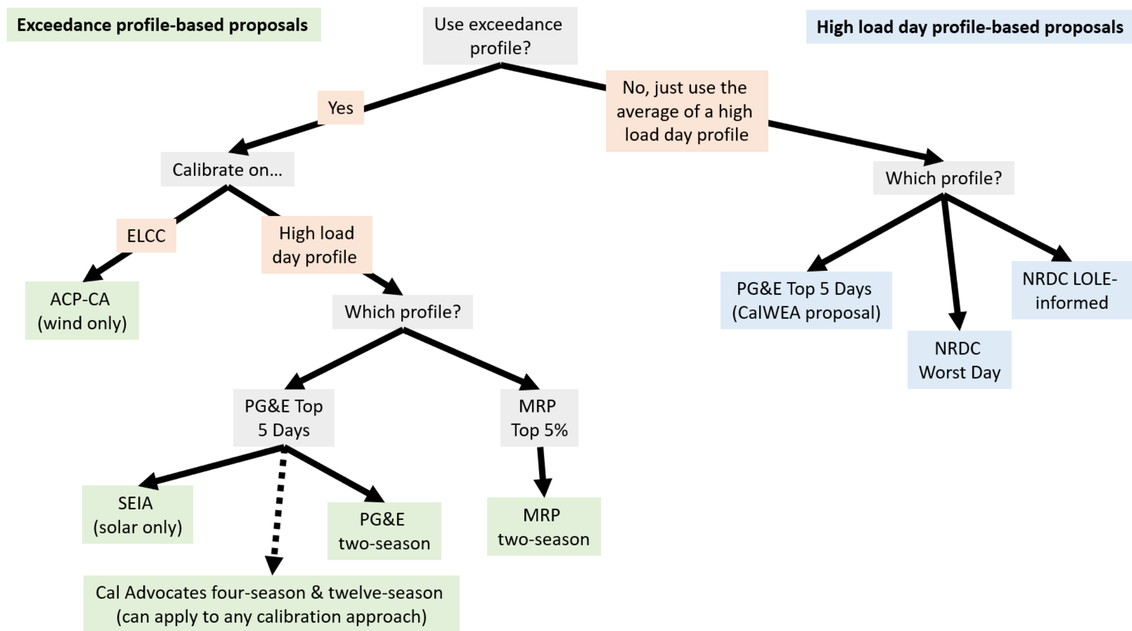
Section Overview

This section provides a comparative analysis of the solar and wind resource counting proposals using a unified dataset. The analysis in this section uses the dataset compiled and shared by PG&E on July 27, 2022.[29] The raw data comprises hourly performance data for solar and wind resources in the CAISO for the six years spanning January 1, 2015 to December 31, 2020. The wind resource performance data is disaggregated between NP15 and SP15 resources. Each hour of performance is converted to a capacity factor by normalizing measured outputs in MW divided by installed solar or regional wind capacity in that month and year.

The solar and wind resource counting proposals can broadly be divided into two separate buckets: proposals that use an exceedance profile and proposals that use the simple average of resource performance on a high load day profile. The decision tree below illustrates how the different proposals relate to each other and the calibration approaches described in this section. The **high load day profile-based proposals** are simpler in that they count resources based on the average of a sample of high load days; the main difference between these proposals is the methodology for sampling high load days. The parties with high load day profile-based proposals are CalWEA and NRDC. The **exceedance profile-based proposals** select an exceedance profile by calibrating their output to some other benchmark profile, either the current ELCC counting conventions (ACP-CA) or a high load day-profile. The two high load day profiles considered are PG&E's Top 5 Days, and MRP's Top 5%. SEIA and PG&E submit proposals calibrated on the PG&E Top 5 Days profile, and MRP submits a proposal calibrated to the MRP Top 5% profile. Cal Advocates submits two hybrid methodologies that can be applied to any of the calibration approaches but in this comparison analysis is applied only to the PG&E Top 5 Days profile.

[29] Available at: *https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/workshop-1---pge---exceedance-analysis---20220727.xlsx*

Figure 27: Proposal Decision Tree



This section applies each solar and wind counting proposal to the same data set to provide an apples-to-apples comparison although NRDC's proposals are an exception. NRDC proposed two conceptually similar proposals, the *Worst Day* and *LOLE-Informed* methodologies. *Worst Day* leverages a similar process to PG&E's proposed Top 5 Days methodology, but assesses peak load days across all years, excluding mild years, and excludes the final step of attempting to match the Top 5 Days results with a single exceedance value. *LOLE-Informed* synthesizes resource performance during the LOLE days experiencing LOLE, or, for months without modeled LOLE, periods of maximum grid stress. *Worst Day* specifically uses SERVM data, and thus is not replicable on this sample dataset. Likewise, *LOLE-Informed* requires iterations that do not lend themselves to this comparison analysis.

This section is organized into seven further sections. The next section resents the exceedance levels proposed by the exceedance profile-based proposals. The subsequent three sections examine the solar proposals, first by comparing the monthly average capacity factors for each proposal, then by comparing the hourly capacity factors for each proposal during reliability risk hours. It concludes by comparing the proposals against each other during reliability risk hours. The wind sections follow in the same pattern: comparing monthly average capacity factors, comparing hourly capacity factors, and comparing proposals against each other.

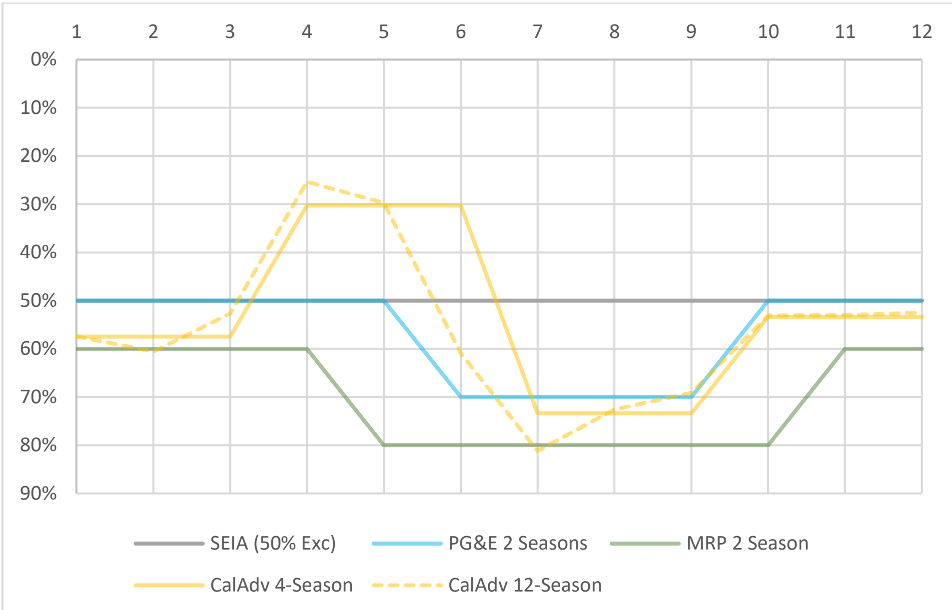
Exceedance Levels

These graphs visualize the exceedance levels proposed by stakeholders that submit exceedance profile-based proposals for solar and wind resources by month.[30] Because exceedance level is inversely correlated with resource output, these graphs use inverted y-axis scales to provide more intuitive interpretation of exceedance levels.

[30] The CalWEA and NRDC high load day profiles are not shown here because they do not select exceedance profiles.

Stakeholders propose four exceedance profile-based options for solar. SEIA proposes using a year-round 50% exceedance level (note that SEIA's proposal only applies to solar resources), PG&E and MRP utilize two-season approaches, and Cal Advocates proposes four-season and twelve-season approaches.

Figure 28: Solar Exceedance Levels



Stakeholders propose five options for setting wind exceedance levels. PG&E and MRP both propose two-season approaches; PG&E utilizes the same exceedance values across all regions, while MRP differentiates exceedance values in one season by region. ACP-California proposes monthly exceedance profiles that align the monthly average capacity factor of each region's wind output with its corresponding current ELCC value (note that the ACP-California proposal only applies to wind resources).31 Cal Advocates proposes four-season and twelve-season approaches to varying exceedance values.

[31] As identified in D.22-08-039, p. 4.

Figure 29: Wind Exceedance Levels: NP15

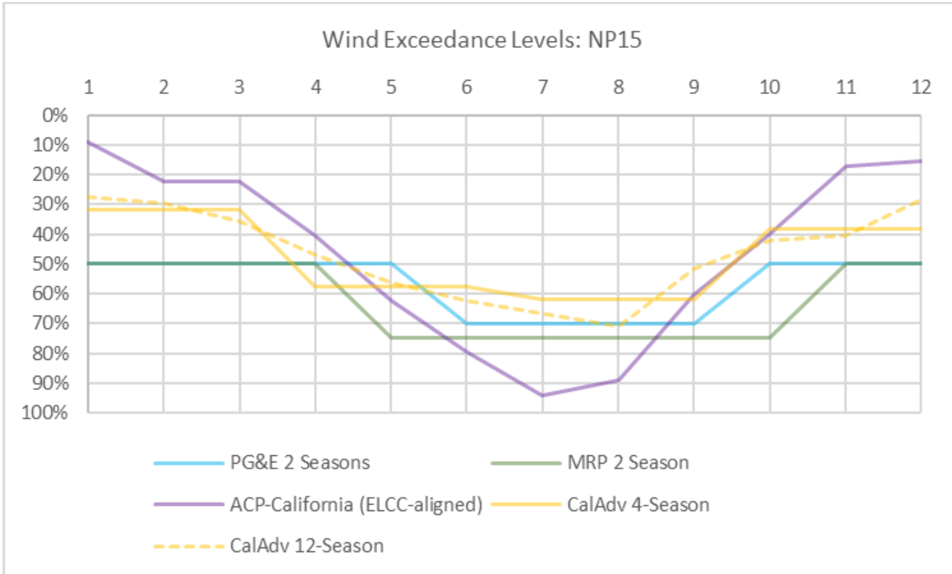
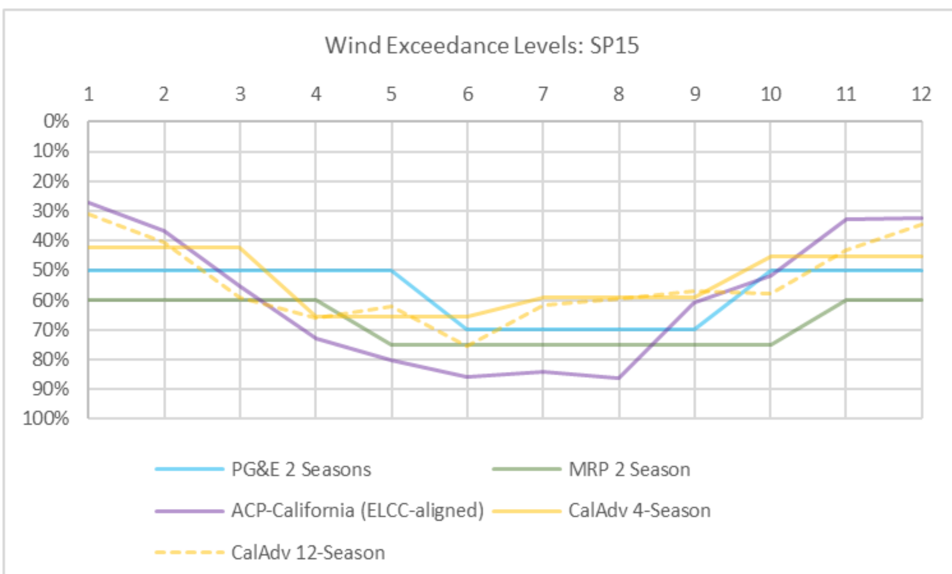


Figure 30: Wind Exceedance Levels: SP15

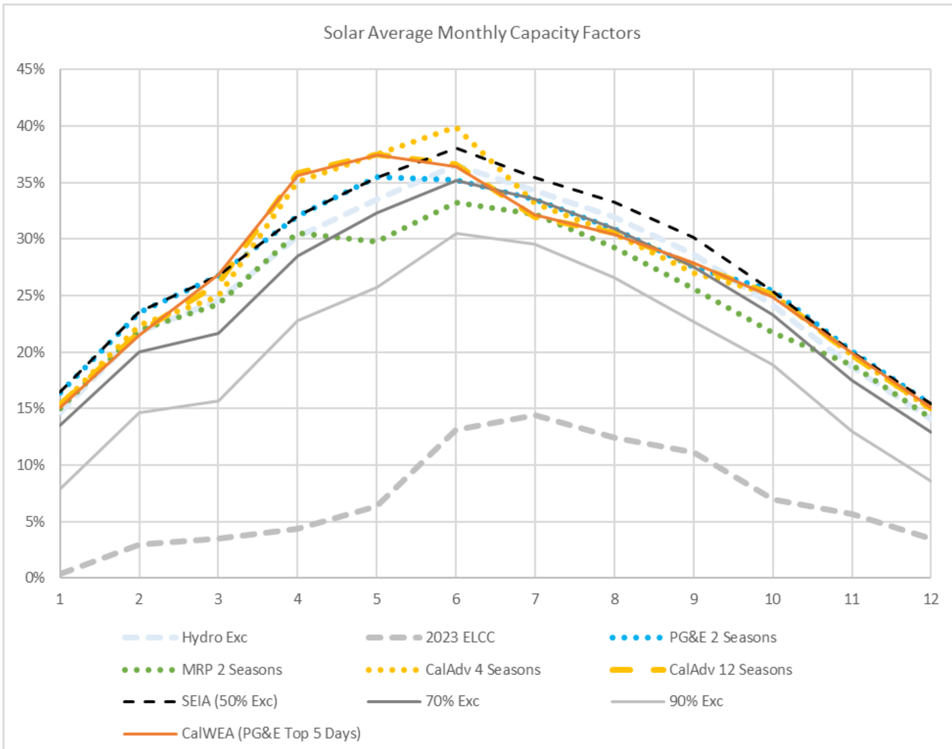


Solar Monthly Capacity Factors

Exceedance profiles are used to identify capacity factors. The following graph illustrates the monthly average solar capacity factor (across all hours) identified by stakeholders' proposed exceedance levels in each month. In months where proposals overlap exactly, the proposals utilize the same exceedance value (e.g., PG&E and SEIA overlap at 50% exceedance value for January to May and October to December).

CalWEA proposes using PG&E's Top 5 Days profile for solar counting, so that profile is replicated here for consideration. Four benchmark profiles are presented alongside the proposal capacity factors. The light gray solid line represents the 90% exceedance profile, and darker gray solid line shows the 70% exceedance profile. The light blue dashed line represents the current hydro exceedance counting method applied to solar resources in all hours,[32] and the gray dashed line represents the average capacity factors of solar as counted using current ELCC values.[33]

Figure 31: Solar Average Monthly Capacity Factors



Solar Hourly Capacity Factors

The following graphs illustrate the hourly capacity factors identified by each solar counting proposal for August and September focusing on the hours ending 16-21 to represent reliability risk hours. All graphs include the same four benchmark profiles as the previous graph (70% and 90% exceedance profiles, hydro exceedance method, and ELCC value).

[32]See D.20-06-031, p. 23, where an 80% weight is applied to the 50% exceedance value and 20% weight applied to the 90% exceedance value of output. Note that the D.20-06-031 applies to capacity offered in Availability Assessment Hours; the approach presented above utilizes all hours.

[33] See D.22-06-050, p. 24.

Figure 32: Solar Average Hourly Capacity Factors: August

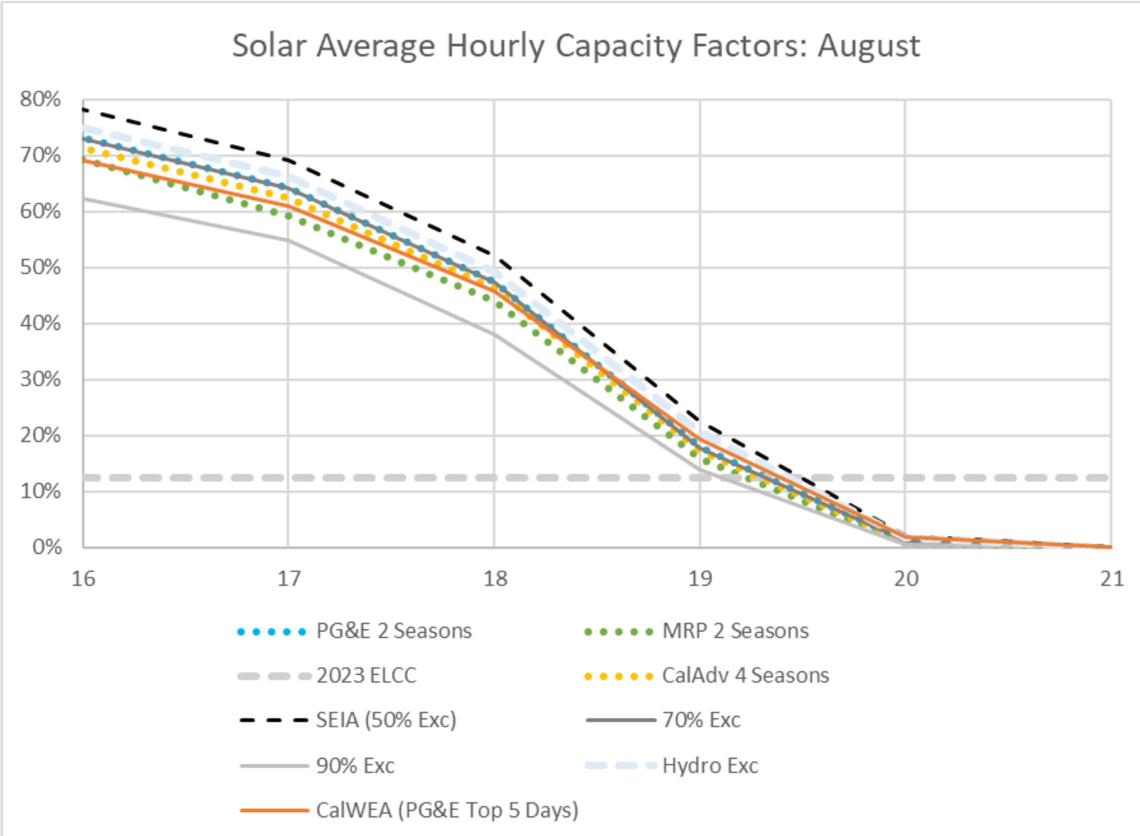
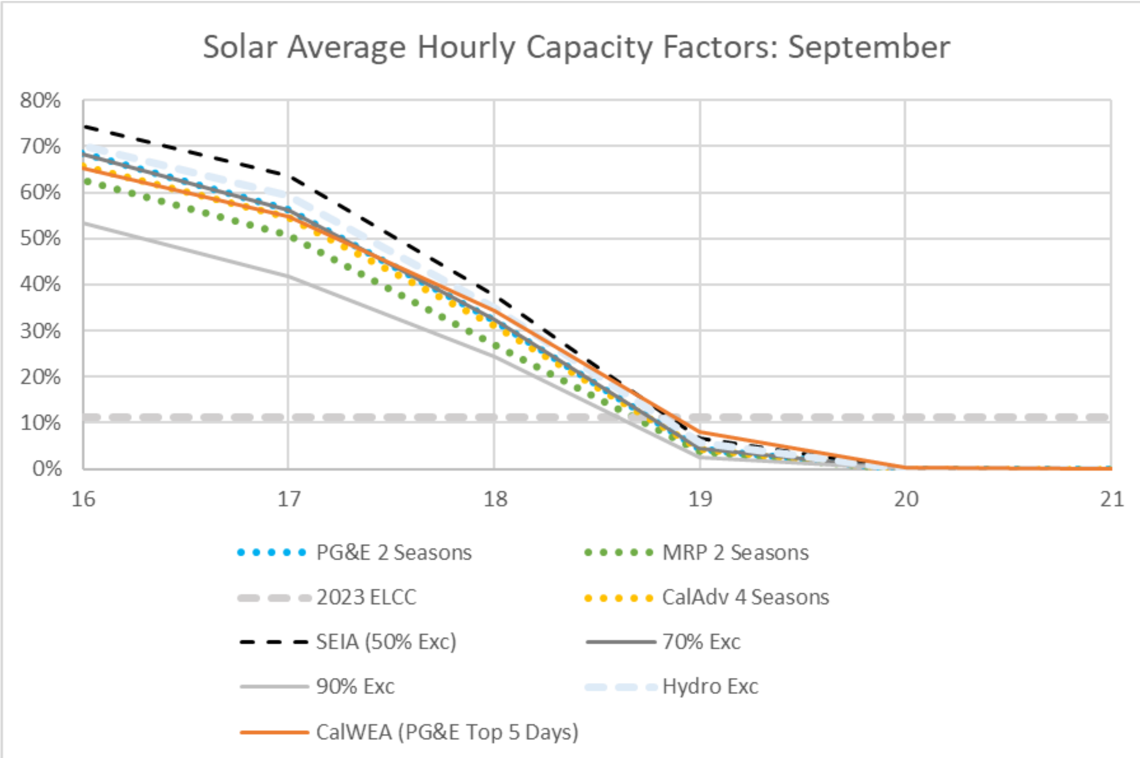


Figure 33: Solar Average Hourly Capacity Factors: September



Solar Calibration

Stakeholders propose two ways to calibrate the selection of solar and wind exceedance levels to address hours of reliability risk. These calibration approaches assume that load is correlated with wind and solar production. This implies that selecting exceedance profiles that best match the wind and solar production on a sample of reliability risk days or hours will reduce some of the risk associated with wind and solar production variability.

Each calibration proposal uses a different sampling approach to identify the periods that represent high reliability risk.

PG&E proposes using the Top 5 Days calibration approach (see proposal starting on page 26). This methodology selects the five days from each month in the 2015-2020 performance data with the highest peak load (6 years * 5 days = 30 days per sample). The hourly resource outputs on that sample of 30 days are averaged to create separate performance profiles for wind and solar resources. CalWEA proposes using this Top 5 Days calibration *as* the resource counting value, rather than taking the next step to calibrate an exceedance profile based on the Top 5 Days value.

MRP proposes using the Top 5% calibration approach (see proposal starting on page 54). This methodology selects days which have any load level that falls into the top 5% of values for that month across all years of the dataset. The number of days this selects ranges from 6- to 19 days per month.

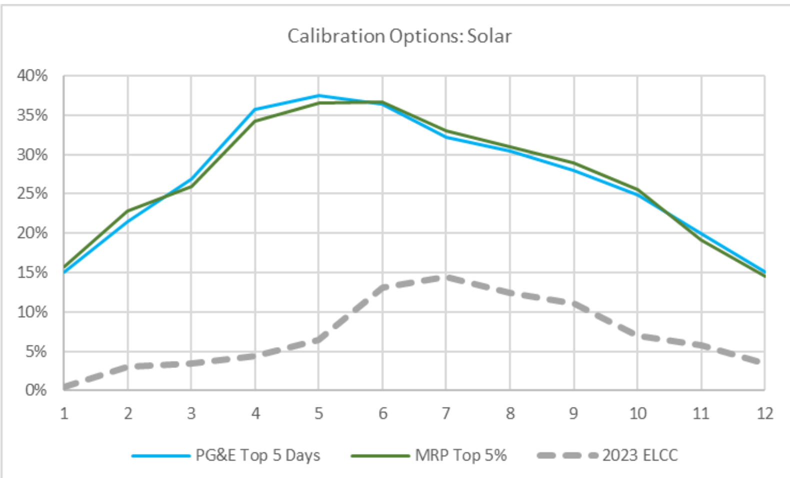
The hourly resource outputs on that sample of 6 to 19 days are averaged to create separate performance profiles for wind and solar resources.

The graph and table below show the average monthly capacity factor set by each of the calibration approaches, along with the current ELCC values (as a capacity factor) as a reference. The differences between each of the proposed calibration approaches are relatively subtle. The annual average capacity factor for the PG&E Top 5 Days approach is 26.9% and for MRP Top 5% it is 27.0%. While the MRP Top 5% and PG&E Top 5 Days Approach are slightly different in most months, they are very similar and never diverge more than 1.4% from each other in any month.

Table 7: Calibration Options: Solar

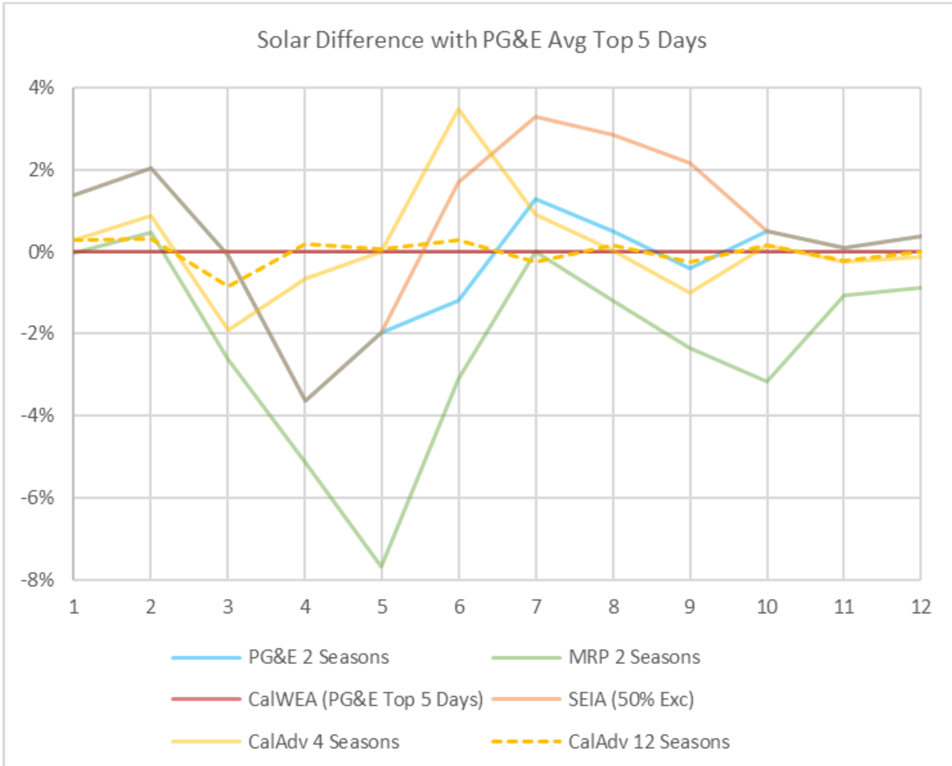
Month	PG&ETop 5 Days	MRP Top 5%	2023 ELCC
1	15.0%	15.7%	0.4%
2	21.5%	22.9%	3.0%
3	26.8%	25.9%	3.5%
4	35.7%	34.3%	4.4%
5	37.5%	36.6%	6.4%
6	36.4%	36.7%	13.1%
7	32.2%	32.9%	14.4%
8	30.4%	31.0%	12.4%
9	27.9%	29.0%	11.1%
10	24.9%	25.6%	7.0%
11	19.9%	19.2%	5.7%
12	15.0%	14.5%	3.5%
Average	**26.9%**	**27.0%**	**7.1%**

Figure 34: Calibration Options: Solar



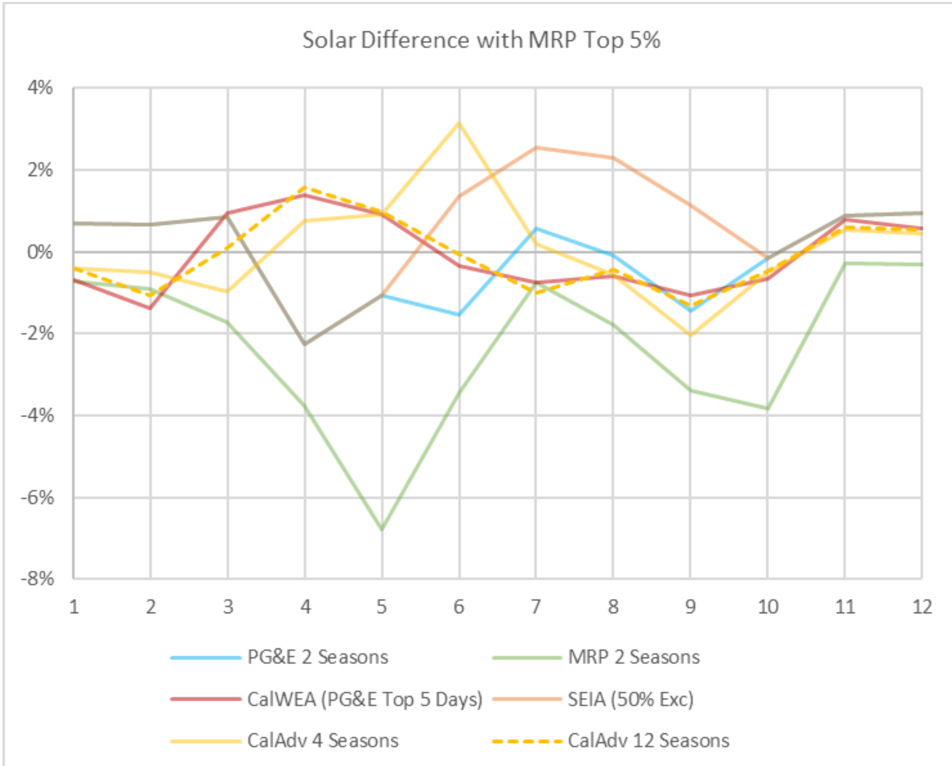
The following graphs illustrate the difference between the capacity factors identified in the six solar counting proposals and the three calibration approaches proposed by PG&E and MRP. A positive number on this graph indicates that the capacity factor identified by a proposal is higher than the calibration level. In other words, a positive number means that the proposal over-counts expected resource capacity relative to the calibration approach. For instance, in September, the SEIA 50% exceedance proposal over-counts solar capacity by around 2% relative to historical performance on the Top 5 Days identified by PG&E.

Figure 35: Solar Difference with PG&E Avg Top 5 Days



The next graph illustrates the same differences measured against MRP's Top 5% calibration approach.

Figure 36: Solar Difference with MRP Top 5%



A few trends emerge across the two graphs. MRP's two-season proposal consistently undercounts solar capacity relative to each calibration approach, indicating that it is a very conservative estimate of resource counting. The other proposals tend to over- or under-count resource capacity by a magnitude of about +/-3%, depending on the month and seasonal exceedance level. The main exception would be Cal Advocates 12-season proposal, whose result is very close to PG&E's Top 5 Day calibration approach. CalWEA's proposal has no difference with the PG&E Top 5 Days approach because it is the same value, while the difference between CalWEA's proposal and MRP's Top 5% represents the difference between the two calibration approaches.

The next set of graphs focus on the hourly capacity factor differences between the six main solar proposals for hours ending 16-21 across all months. Differences are again shown between the proposals and the PG&E Top 5 Days calibration approach and the MRP Top 5%. The graphs for 24-hour differences are available in the attached Excel workbook on the "Solar Calibration" tab.

Figure 37: Difference between PG&E Top 5 Days Calibration and Hourly Capacity Factor by Month for Solar

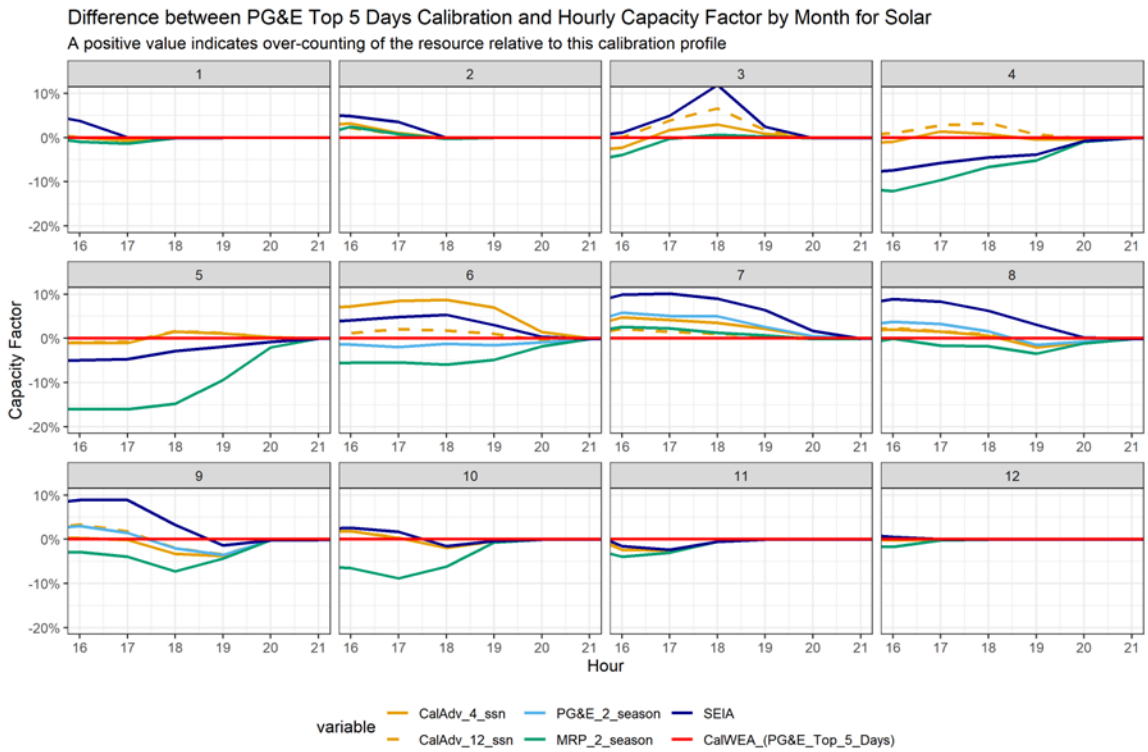
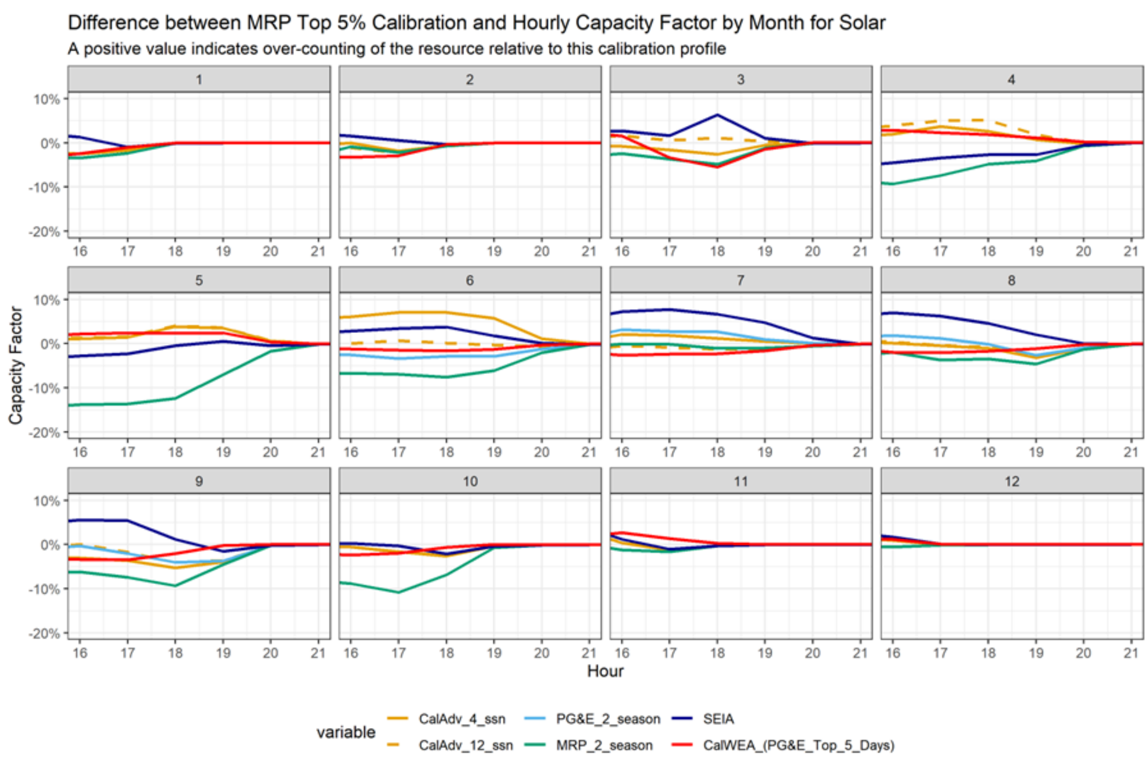


Figure 38: Difference between MRP Top 5% Calibration and Hourly Capacity Factor by Month for Solar



Wind Monthly Capacity Factors

While solar exceedance profiles have a relatively stable shape across percentiles in any given month, wind performance is much more variable. The following three graphs illustrate the monthly average wind capacity factor identified by stakeholders' proposed exceedance levels in each month.

Most stakeholders have proposed using region-specific exceedance values. Therefore, throughout this comparison analysis we calculate region-specific exceedance values and then aggregate them to calculate a system average that is weighted using installed capacity for NP15 (1404 MW) and SP15 (4765 MW) wind dating to 2020.[34] NP15 resources generally have higher capacity factors, along with higher variation in the distribution of their historical performance. On the other hand, SP15 resources generally have lower capacity factors, but lower variation, indicating that SP15 wind performance is more steady historically.

CalWEA proposes using PG&E's Top 5 Days profile for wind counting, so that profile is replicated here for consideration. Three benchmark profiles are presented alongside the proposal capacity factors. Whereas the solar graph included ELCC values as a benchmark, ACP-California proposes selecting the exceedance value that matches the average monthly capacity factor to the ELCC value. Thus, when looking at the average monthly capacity factors for wind resources, the ACP-California proposal is identical to the current ELCC values.[35] The light gray solid line represents the 90% exceedance profile, and the black solid line shows the 50% exceedance profile. The light blue dashed line represents the current hydro exceedance counting method applied to wind resources in all hours.[36] The two graphs below illustrate the average monthly capacity factors identified by each of the wind proposals.

[34] The two exceptions are PG&E's two-season proposal (which applies the same exceedance value to all wind regions) and CalWEA's ENLR proposal (which was developed without regard to region specificity).
[35] See D.22-08-039, p. 4.
[36] See D.20-06-031, p. 23, where an 80% weight is applied to the 50% exceedance value and 20% weight applied to the 90% exceedance value of output. Note that the D.20-06-031 applies to capacity offered in Availability Assessment Hours; the approach presented above utilizes all hours.

Figure 39: Wind Average Monthly Capacity Factors: NP15

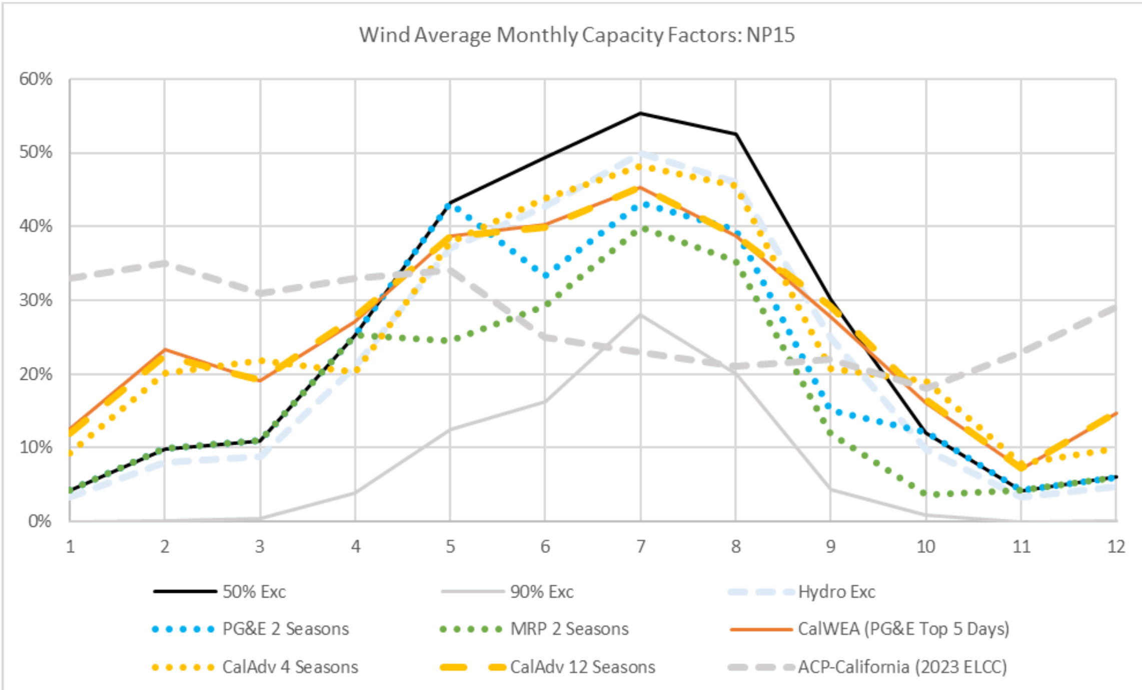
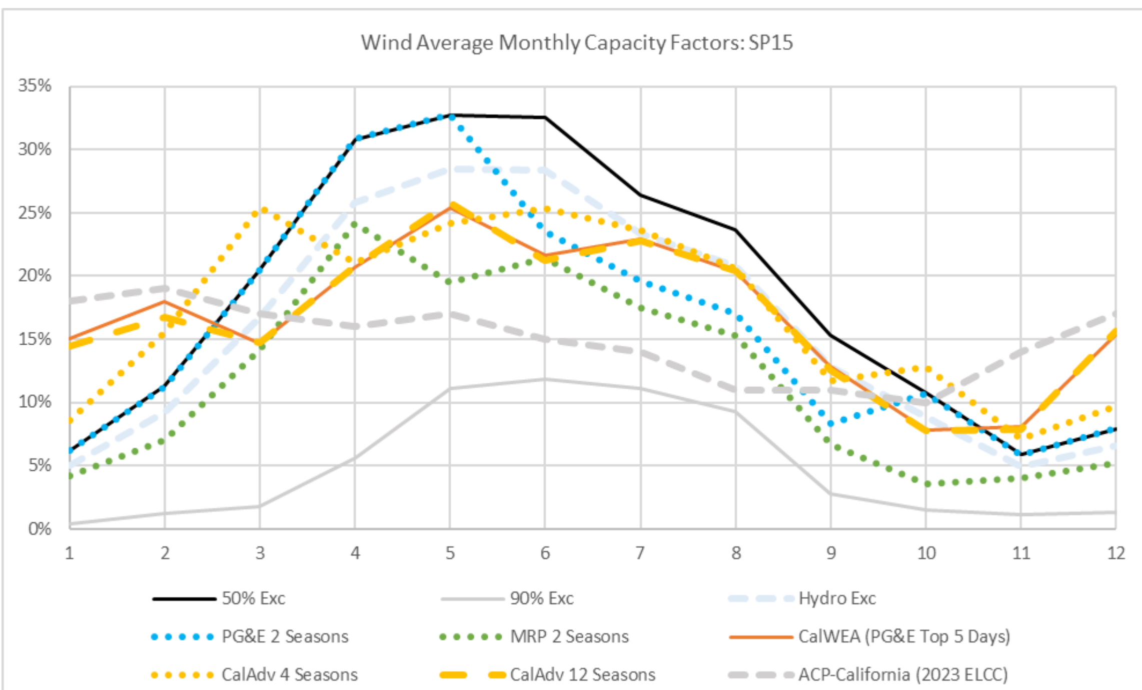


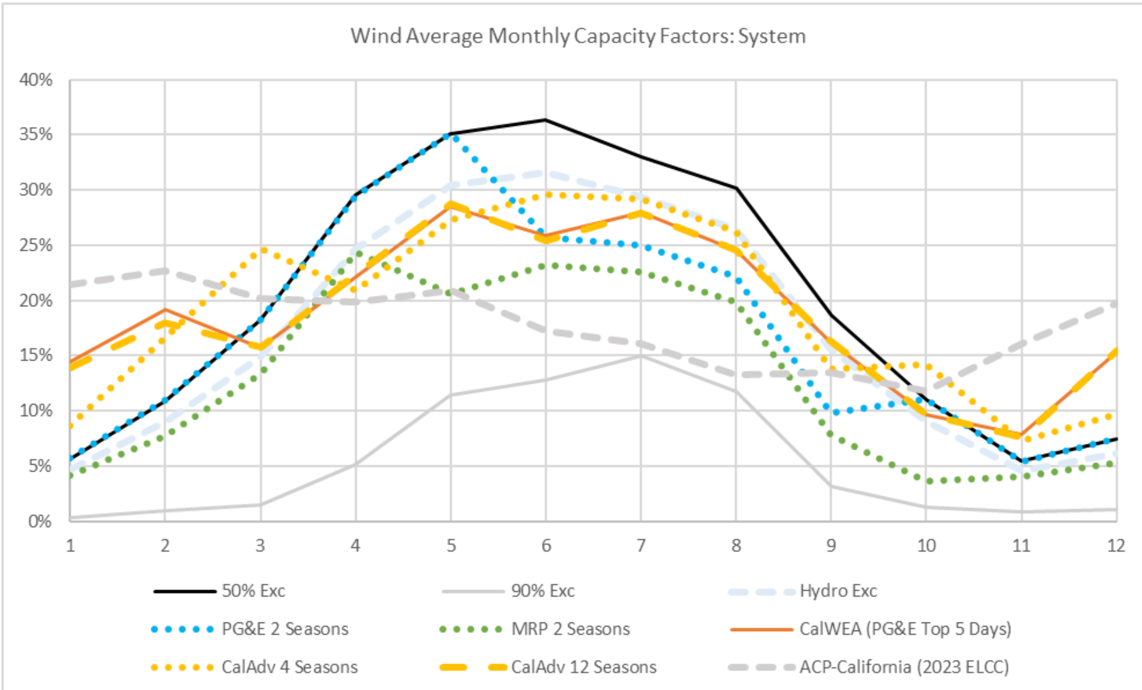
Figure 40: Wind Average Monthly Capacity Factors: SP15



Comparing the 50% exceedance benchmarks between regions demonstrates that the median SP15 wind performance tends to be highest in April to June, while median NP15 wind performance is highest in June to August. Note the differing y-axis scales between the two graphs. The next graph combines

NP15 and SP15 wind performance (weighted by 2020 installed capacity) to show the average monthly capacity factors identified by the wind proposals.

Figure 41: Wind Average Monthly Capacity Factors: System



Wind Hourly Capacity Factors

The following graphs illustrate the average hourly capacity factors identified by the six wind proposals for the full system for the months of May (a high-wind variability month), August and September (elevated reliability risk months). Note that the flat 24-hour ELCC value is equal to the average of the ACP-California exceedance profile. Likewise, no single proposal consistently matches or is less than the ELCC monthly ELCC values in hours ending 16-21; even the 90% exceedance profile surpasses ELCC values in August after HE18.

Figure 42: System Wind Average Hourly Capacity Factors: May

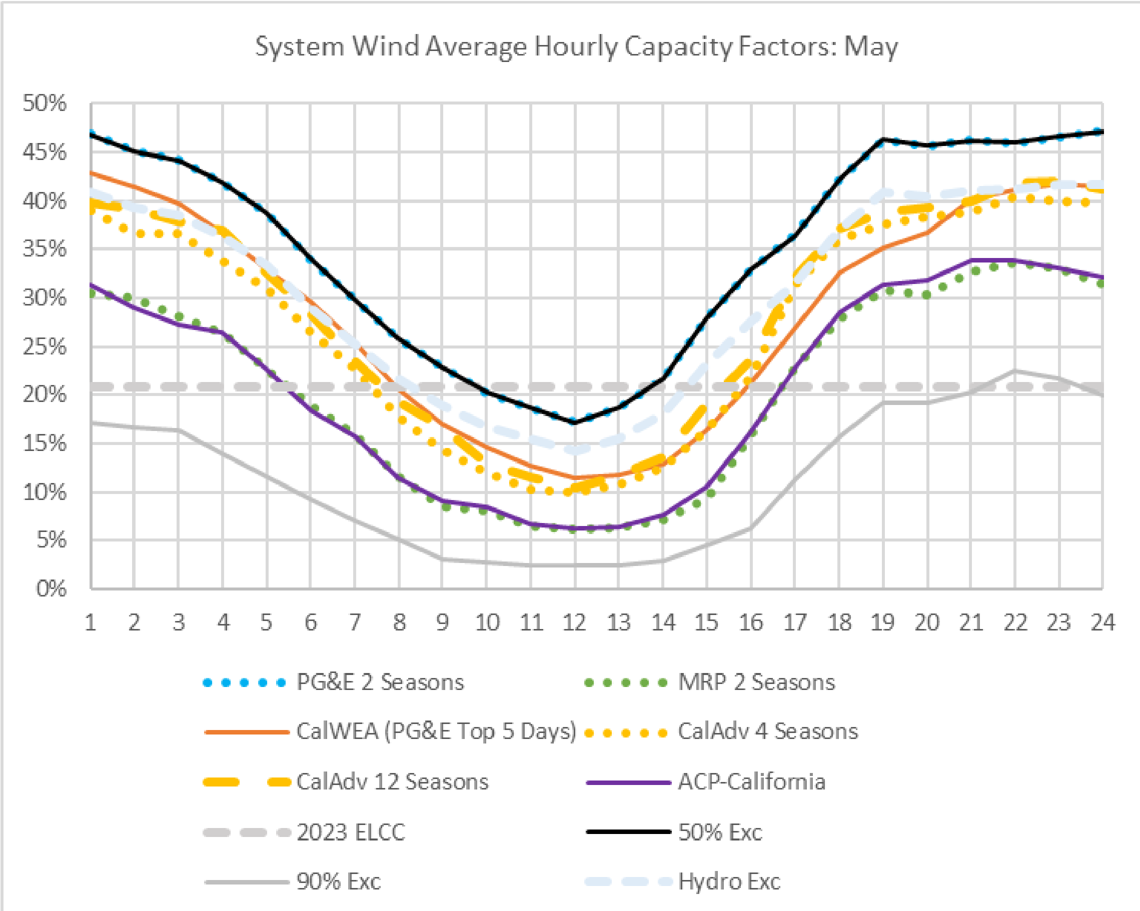


Figure 43: System Wind Average Hourly Capacity Factors: August

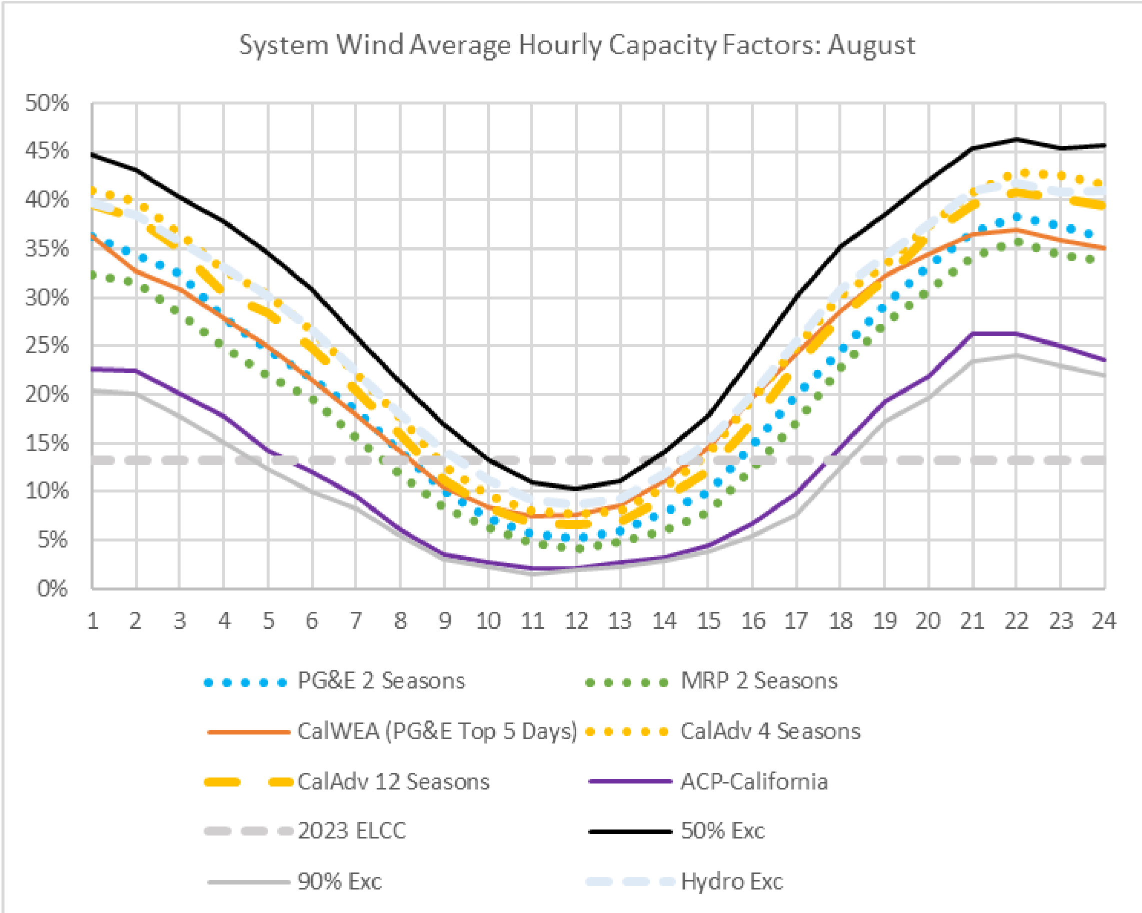
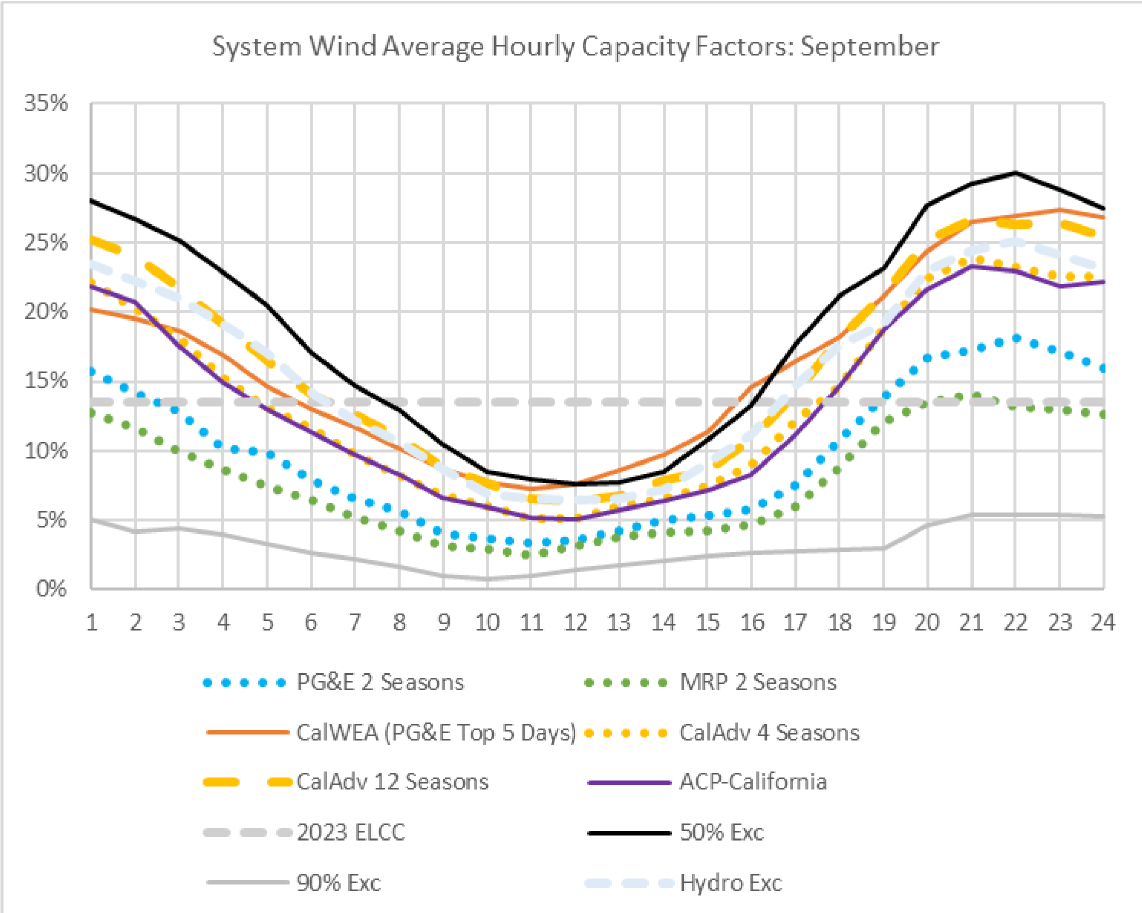


Figure 44: System Wind Average Hourly Capacity Factors: September



Wind Calibration

The same calibration approaches stakeholders proposed for solar resources are useful for informing the choice of an exceedance value for wind resources. This comparison analysis utilizes the same method for developing calibration profiles as discussed in the counterpart solar section above, although the calibration profiles were developed for each wind region (NP15 and SP15) first, before combining them into a single system average (weighted by 2020 installed capacity).[37]

The graph and table below show the average monthly capacity factor set by each of the calibration approaches, along with the current ELCC values (as a capacity factor) as a reference. The differences among each of the proposed calibration approaches are more apparent than with solar. For example, MRP's Top 5% approach has higher average capacity factors from March through August, with the biggest differences in April and November. The annual average capacity factor for the PG&E Top 5 Days approach is 19.0% and for MRP Top 5% it is 20.3%. Therefore, the PG&E Top 5 Days approach would reasonably be considered the more conservative of the calibration approaches for wind in the aggregate. Conversely, while the current ELCC values are relatively stable and flat throughout all

[37] The exception is CalWEA's ENLR approach, which did not disaggregate between NP-15 and SP-15 wind.

months (annual average of 17.7%), they consistently yield higher capacity factor estimates in November to February than all the stakeholder proposals.

Figure 45: Wind Calibration Options: System

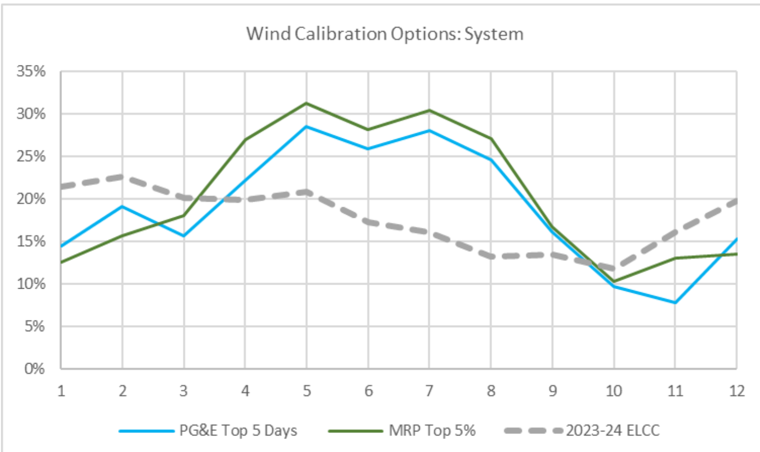
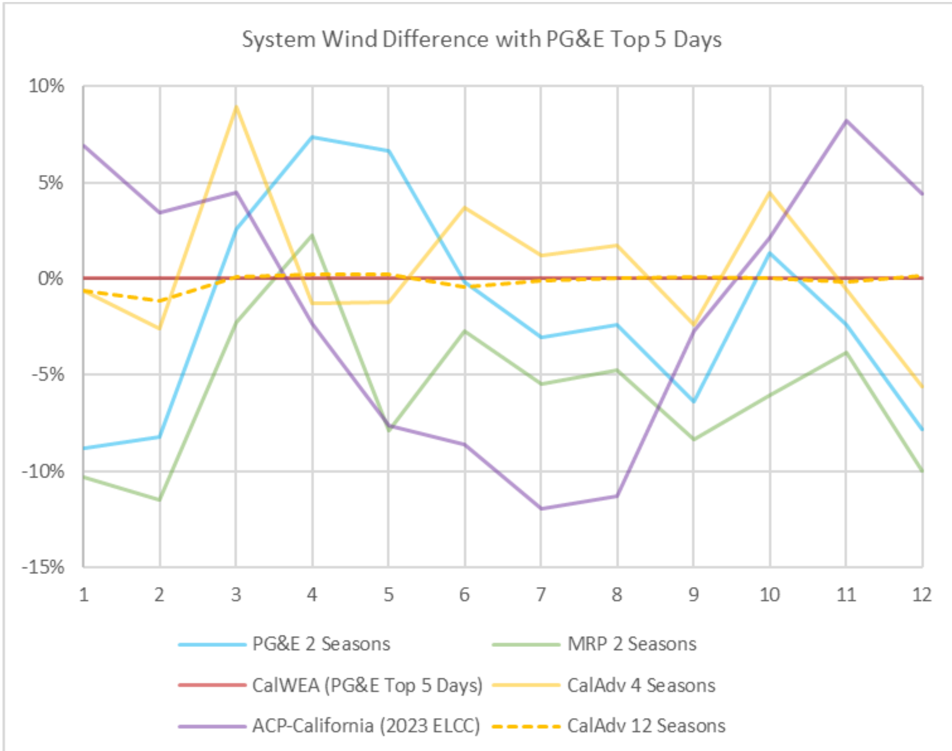


Table 8: Wind Calibration Options: System

Month	PG&E Top 5 Days	MRP Top 5%	2023-24 ELCC
1	14.5%	12.5%	21.4%
2	19.2%	15.6%	22.6%
3	15.7%	18.1%	20.2%
4	22.2%	27.0%	19.9%
5	28.5%	31.2%	20.9%
6	25.9%	28.2%	17.3%
7	28.0%	30.4%	16.0%
8	24.5%	27.1%	13.3%
9	16.2%	16.7%	13.5%
10	9.7%	10.3%	11.8%
11	7.9%	13.1%	16.0%
12	15.3%	13.5%	19.7%
Average	**19.0%**	**20.3%**	**17.7%**

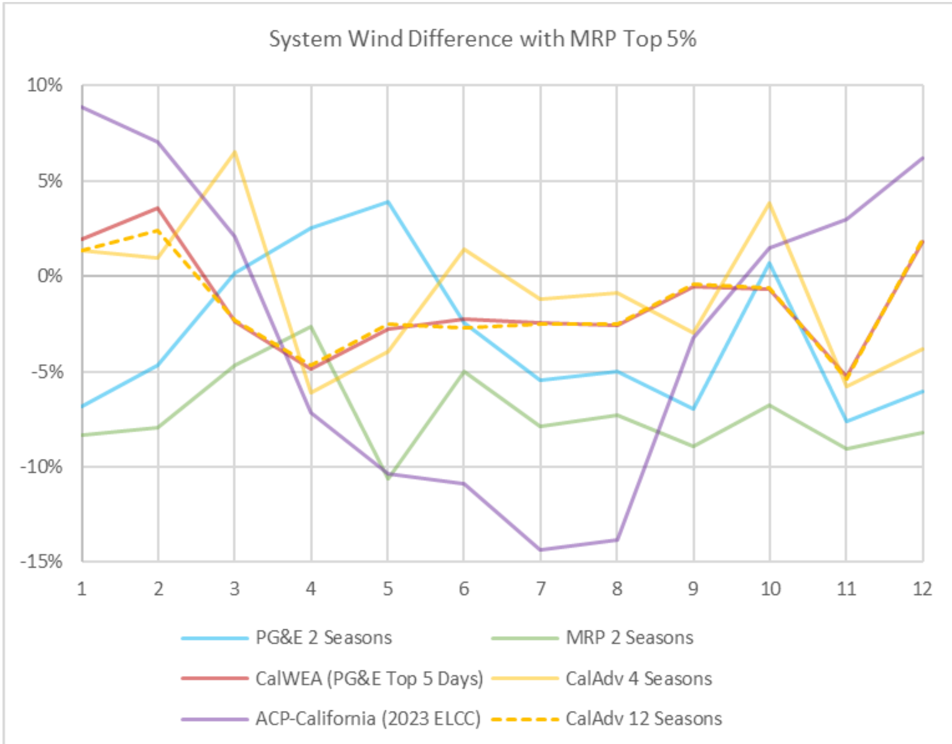
The following graphs illustrate the difference among the capacity factors identified in the six wind counting proposals and the calibration approaches proposed by PG&E and MRP. A positive number on these graphs indicates that the capacity factor identified by a proposal is higher than the calibration level. In other words, a positive number means that the proposal over-counts expected resource capacity relative to the calibration approach. For instance, in January, the ACP-California proposal over-counts solar capacity by around 7% relative to historical performance on the Top 5 Days identified by PG&E. The next graph shows the differences between monthly average capacity factors and PG&E Top 5 Day calibration approach. PG&E's two-season proposal fluctuates above and below the calibration level along with ACP-California's ELCC-calibrated proposal, while MRP's two-season proposal is below for all months except April. Cal Advocates' 12-season proposal almost mirrors the Top 5 Days calibration because it seeks to minimize that difference. CalWEA's proposal is the Top 5 Days calibration approach.

Figure 46: System Wind Difference with PG&E Top 5 Days



The next graph shows the differences between the monthly average capacity factors identified by different exceedance values and MRP's Top 5% calibration approach.

Figure 47: System Wind Difference with MRP Top 5%



The next set of graphs focus on the hourly capacity factor differences among the six wind proposals for hours ending 16-21 across all months. Differences are again shown between the proposals and the PG&E Top 5 Days calibration approach and the MRP Top 5% approach. The graphs for 24-hour differences are available in the attached Excel workbook on the "Wind Calibration" tab.

Figure 48: Difference between PG&E Top 5 Days Calibration and Hourly Capacity Factor by Month for System Wind

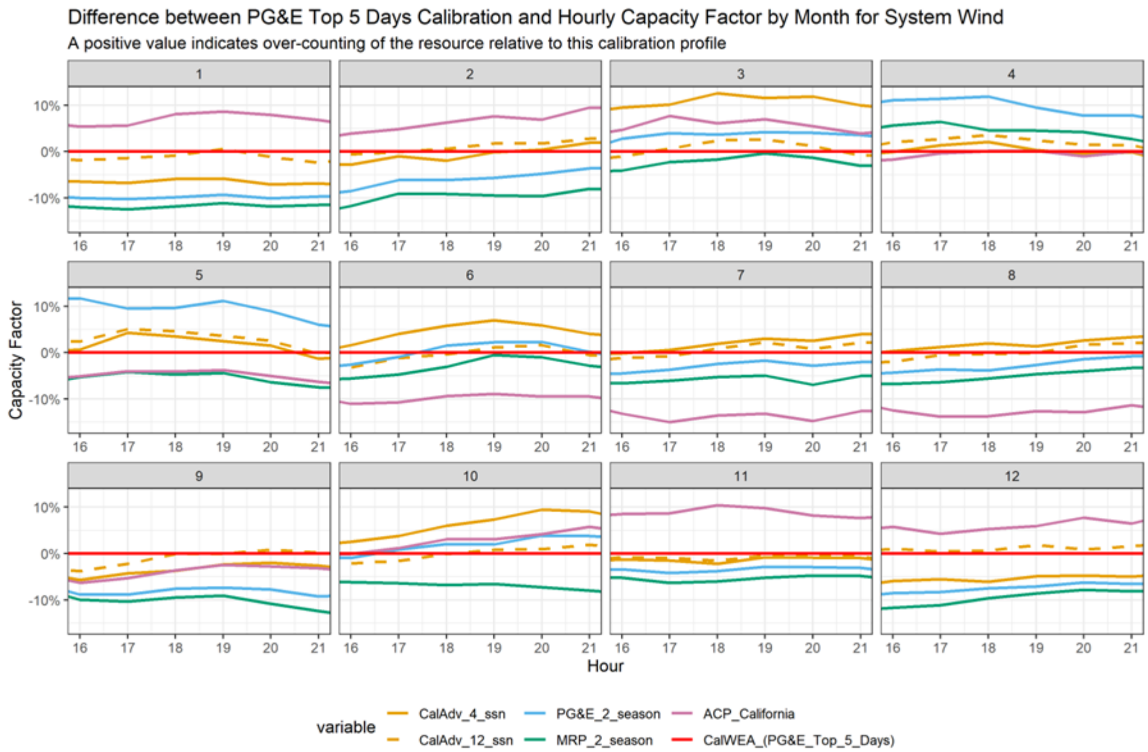
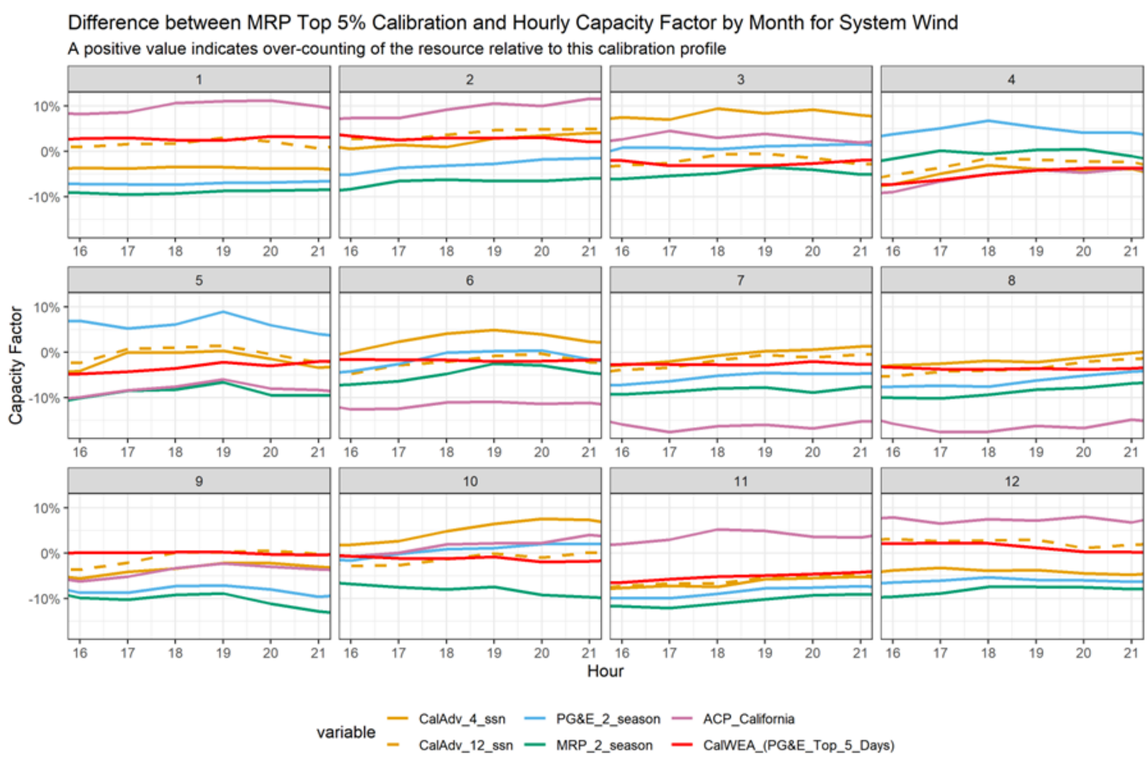


Figure 49: Difference between MRP Top 5% Calibration and Hourly Capacity Factor by Month for System Wind



VI. Consensus and non-consensus items

- Methodology: Non-consensus
  - Exceedance, with the level set based on resource production during high load days (PG&E, MRP, CalPA, SEIA)
  - Exceedance, calibrated to ELCC (ACP)
  - High load day profile based on resource production during high load days (NRDC, CalWEA)
- Data source: Near-consensus
  - Recorded (most parties; NRDC if data is available)
  - Modeled (NRDC, if data isn't available; other parties recognize some wind regions don't have actual data and will need modeled data)
- Benchmarking and selection approach:
  - Consensus, use high load day profiles
  - Non-consensus on definition of high load day profile (PG&E top 5 v. MRP top 5%)
- Calibration: Non-consensus
  - None needed (CalWEA)
  - Calibrate to ELCC (ACP)
  - Calibrate within PRM tool (PG&E, NRDC)
- Level to apply methodology: Consensus: Regions and Technologies: Consensus, recognizing ED may need some flexibility for solar given stakeholders don't have access to technology-specific data for solar
  - Solar
    - Fixed
    - Tracking
  - Wind
    - Northern California (NP15)
    - Southern California (SP15)
    - Northeast Out of State (OOS) Wind (Wyoming/Idaho)
    - Northwest OOS Wind (Washington/Oregon)
    - Southwest OOS Wind (Arizona/New Mexico)
    - Offshore Wind

VII. Questions for parties

- Do parties support an exceedance-based approach or high-load day profile approach?
- For the high-load day profile (which is used in the exceedance-based approaches as well), do parties have a preference for PG&E's top 5-day approach or MRP's top 5% approach?
- Do parties believe the wind and solar profiles need to be calibrated? If so, should they be calibrated to ELCC or within the PRM tool?
- Do parties support using actual data or modeled?
  - Please include any input you have on: How many years of data should be used? How should it be updated? How often should it be updated?

- If using recorded, how should curtailments be treated? If you want to account for curtailments, do you have a proposal for how to do it given data limitations?

VIII. References

Authors:

- **PG&E Excel Tool:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/workshop-1---pge---exceedance-analysis---20220727.xlsx
- **CalPA Excel Tool (under RA Reform Excel Workbooks):** https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-history
- **Energy Division 7/27 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/7-27-2022-solar-and-wind-exceedance/workshop-1_ed_220727.pdf
- **PG&E 7/27 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/7-27-2022-solar-and-wind-exceedance/workshop-1_pge_220727.pdf
- **CalWEA 7/27 Presentation**: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/7-27-2022-solar-and-wind-exceedance/workshop-1_calwea_220727.pdf
- **SEIA 7/27 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/7-27-2022-solar-and-wind-exceedance/workshop-1_seia_220727.pdf
- **NRDC 7/27 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/7-27-2022-solar-and-wind-exceedance/workshop-1_nrdc_220727.pdf
- **ACP 7/27 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/7-27-2022-solar-and-wind-exceedance/workshop-1_acp_220727.pdf
- **CalWEA 8/23 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-23-2022-planning-reserve-margin/workshop-5_calwea_220823.pdf
- **NRDC 8/23 Presentation**: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-

materials/resource-adequacy-history/8-23-2022-planning-reserve-margin/workshop-5_nrdc_220823.pdf

- **PG&E 8/23 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-23-2022-planning-reserve-margin/workshop-5_pge_220823.pdf
- **Pattern ACP 8/23 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-23-2022-planning-reserve-margin/workshop-5_pattern-acp_220823.pdf
- **CalPA 10/6 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_cpa_221006.pdf
- **CalWEA 10/6 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_calwea_221006.pdf
- **PG&E 10/6 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_pge_221006.pdf
- **CAISO 10/6 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_caiso_221006.pdf
- **NRDC 10/6 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_nrdc_221006.pdf
- **MRP 10/6 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_mrp_221006.pdf

iii. Resource Counting for Hybrids

Authors: PG&E, with support from CESA, SEIA, SCE

I. Background

Authors: PG&E

Discussions pertaining to development of a hybrid resource counting methodology compatible with a 24-hour slice RA framework have generally aligned on a number of baseline principles that mirror principles for other resources. Firstly, counting frameworks for hybrid resources must allow those resources to be counted based on their contribution to grid reliability, and must effectively facilitate that contribution.

A number of parties made proposals during RA Reform phase 1 consistent with these principles. SCE emphasized counting resources based on their capabilities.[38] PG&E proposed adapting the existing counting methodology, as established in D.20-06-031 to the 24-hour slice framework.[39] SEIA/LSA similarly supported refining existing rules.[40] CESA highlighted the need for clarity of valuations, especially for paired resources claiming a portion of the Investment Tax Credit (ITC).[41] Finally, Cal Advocates agreed that existing QC rules were appropriate for hybrid and co-located resources.[42] Accordingly, proposals made in the later recent workshops built on these earlier proposals.

Existing CPUC rules apply to resources with charging restrictions only. They offer a relatively simple starting point for SoD modifications. Under these rules total QC is the sum of the effective storage component QC and the effective renewable component QC. The effective QC for the energy storage component equals the minimum of "(1) The energy (MWh) production from the renewable resource from 2 hours after the net load peak until 2 hours before the net load peak assuming charging is done at a rate less than or equal to the energy storage's capacity. This renewable charging energy is then divided by 4 hours to determine the QC; or (2) The QC of the energy storage device".[43] For the renewable component, QC equals the capacity less what is required to charge the storage multiplied by the current ELCC factor.

Passage of the Inflation Reduction Act (IRA) allows for application of tax benefits to standalone storage, which changes the previous incentive to pair storage and renewable resources to capitalize on the tax benefits. This change may limit the number of resources with charging restrictions going forward, which are the subject of the following proposed changes.

In D.22-06-050 the Commission agreed that applying the existing QC methodology to the 24-hour slice framework was appropriate and agreed with PG&E that it should be updated to incorporate revised renewable counting rules. The Commission directed parties to further refine PG&E's proposal to adapt the existing QC methodology to use updated renewable profiles in these Workstreams.

II. Issues

Authors: PG&E

Key issues include:

- Accounting for different hybrid configurations
- Partial deliverability
    - Can the renewable component of a hybrid resource count towards the charging requirement of the storage component even without sufficient deliverability?
- Should partial grid charging be accounted for in these rules?
- Impact of IRA

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[38] Reform Report p.14.
[39] *Id* p.30.
[40] SEIA/LSA Comments on Reform Report, March 24, 2022, p. 10.
[41] CESA Comments on Reform Report, March 24, 2022, p.7.
[42] Cal Advocates Comments on Reform Report, March 24, 2022, p.6.
[43] D.20-06-031 p.31.

III. Presenters and Dates

Authors: PG&E

- August 3, 2022:
  - SCE (hybrid validation logic)
- August 10, 2022:
  - PG&E
  - CESA
  - SEIA
- August 23, 2022:
  - CAISO (deliverability and use of co-located, energy-only resources for meeting charging requirements)

IV. Proposal Summaries

a. PG&E

Authors: PG&E

PG&E's proposal is consistent with the direction adopted in D.22-06-050 directing parties to further refine PG&E's original proposal. Accordingly, PG&E's proposal as articulated in the workshop on August 10th is a materially similar but refined iteration of PG&E's original phase 1 proposal.

PG&E proposes a counting methodology for hybrid resources with charging restrictions that keeps the existing methodology with a series of changes. First, the profile used to determine if the renewable resource provides sufficient charging capacity would be based on the final profile adopted for wind and solar counting. The methodology would update the storage capacity to account for charging losses (this increases the renewables needed to fully charge the storage component). The methodology used to determine sufficient charging capacity would account for all renewable capacity, even if some of it isn't deliverable. Any remaining capacity from the generating resource after the energy storage components' charging requirement is met would be counted using the new renewable counting rule treatment.

Lastly, resources without charging restrictions, and therefore not subject to these rules, should be counted using the methodology applied to the relevant standalone generating resource type, as is the practice today. The storage portion of these resources would, like all storage resources, be associated with a requirement for adequate charging capacity.

b. CESA

Authors: CESA

CESA's position regarding paired (hybrid and co-located) resources stems from the fact that current valuation methodologies do not reflect the diversity of these configurations, nor do they properly capture the overall value these resources can provide to the system. Overall, CESA agrees with SCE's characterization (in its table of configurations) of the wide diversity of potential paired configurations, mainly driven by the participation pathway, the prioritization of on-site charging, and the deliverability allocation among the components. This being said, CESA underscores the following notions as essential for any paired resource framework within slice-of-day (SOD).

1. At its core, the valuation of paired resources within SOD should continue to be additive.
    a. In determining the contribution of the VER component, assuming the component is fully deliverable, exceedance should replace ELCC as the methodology to determine the contribution of the VER.
2. Paired resources should be able to be characterized as charging exclusively on-site or allowing grid-charging.
    a. If a resource allows for grid charging, the contribution of the resource's components to meeting SOD needs shall be assigned individually.
        i. In this case, the charging sufficiency verification shall be conducted as part of the LSE showing (*i.e.,* externally).
    b. If a paired resource is expected to charge fully on-site, the contribution of the resource's components must be based on sufficiency internally, since only on-site generation will be able to charge the storage asset
    c. Under either of these cases, it may be necessary to cap the maximum hourly additive value of these components due to interconnection limitations.
3. Under either of these circumstances, the deliverability of the VER component (or lack thereof) should not pose a limitation to comply with the internal sufficiency check.
    a. If the VER component is not deliverable, it may support the storage for the internal charging sufficiency verification, but it may not provide any additional RA value.
4. For both paired resources that charge exclusively on-site or those that allow grid-charging, any form of charging sufficiency verification (internal or external) should not prescribe when the storage is charging, only that there is sufficient energy across the showing to support storage utilization.
    a. CESA does not support static hybrid shapes
    b. Paired resources should be shown within their operational parameters but as separate assets in the showing

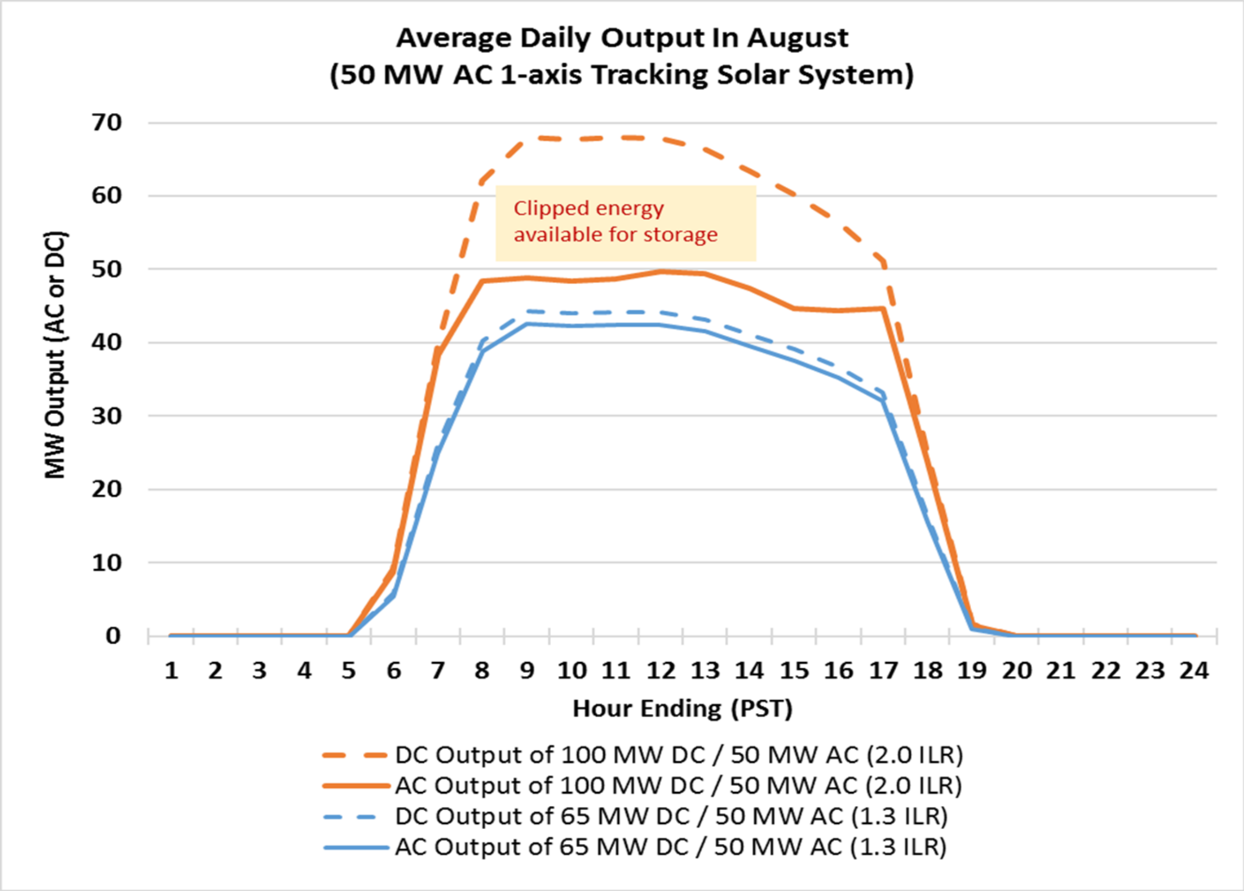
c. SEIA

Authors: SEIA

The SoD framework incorporates and is consistent with the "additive" approach that the Commission adopted in D.20-06-031 to counting the RA capacity of hybrid solar-paired storage projects. The 24-hourly slice approach ensures that the LSE purchasing the output from such a project has adequate excess energy to charge the associated storage.

SEIA's presentation in Workshop 3 focused on how to adapt the SOD framework for a certain type of solar-storage hybrid – DC-coupled systems. These systems can capture and store additional direct current (DC) solar output that otherwise would be lost or "clipped" in the inverter, as shown in the figure below.

Figure 50: Average Daily Output in August (50 MW AC 1-axis Tracking Solar System)



LSEs that contract with DC-coupled hybrids should be able to show this clipped solar energy as part of the excess energy used to fill storage. The following data will be needed from DC-coupled systems to calculate and verify this additional available energy:

1. The project's Inverter Loading Ratio (DC output divided by alternating current (AC) output),
2. An engineering estimate of internal losses,
3. Maximum charging capacity of the paired storage, and

A showing of the average hourly clipped energy available to be stored in each month, consistent with the three previous parameters.

a. CAISO

Authors: CAISO

At the August 23rd workshop, the CAISO clarified its deliverability study processes and noted that only fully deliverable resources (Full Capacity Deliverability Status or FCDS), the deliverable part of a resource (Partial Capacity Deliverability Status or PCDS) or interim deliverable resources (Interim Deliverability Status or IDS) can provide resource adequacy capacity per the CAISO tariff. Per the CAISO tariff section 40.4.6, the CAISO will reduce the Local Regulatory Authority (LRA)- established QC values for any part proven to be undeliverable to the aggregate of load. The CAISO stressed that energy-only (EO) resources cannot be used for resource adequacy to serve load or to charge storage resources across the transmission system, and this should not change under Slice of Day.

Regarding co-located resources at the same point of interconnection (POI), the CAISO outlined advantages and challenges of allowing the co-located energy-only (EO) resource to count towards storage charging under Slice-of-Day. Under this type of configuration, the EO resource would have no transmission impact. Allowing the co-located EO resource to count towards storage charging, would provide equal treatment compared to hybrid resources under a single resource ID. However, the EO resource would not be a part of the RA fleet and would not be subject to CAISO RA rules including must-offer obligations and outage substitution. Additionally, allowing the co-located EO resource to count towards storage charging would be a new type of configuration only used by the CPUC Local Regulatory Authority (LRA).

b. SCE

Authors: SCE

In its proposed SOD resource database and tools SCE presented hybrid counting and validation logic.[44] The key feature of this validation is a check to ensure the total showing amount is not larger than can be supported by the underling energy resource. To facilitate this the hybrid showings require additional accounting of expected energy resource production, expected storage charging pattern, loss accounting, and the final slice by slice result. This validation logic only applies to true hybrids and combinations of resources that operate as hybrids.

In the August 10 workshop SCE presented a table seeking to clarify what parties consider hybrids or sufficiently like hybrids. SCE pointed out several parties were referring to facilities that do not operate as hybrid as "hybrid". SCE recommends such facilities that do not operate as hybrids be considered separate facilities for RA counting purposes.

V. Comparison of the proposals

Authors: PG&E

- The PG&E, CESA, and SEIA proposals all address changes that need to be made to the hybrid counting methodology under SOD.
- SEIA's proposal adds additional detail on how DC-coupled systems should be treated under SOD.
- CAISO addresses deliverability issues with hybrid and co-located resources, pointing out that allowing co-located, energy-only resources to be used for charging purposes would provide equal treatment compared to hybrid resources.
- SCE adds details on how to show and validate hybrid resources, as well as seeks to delineate the different types of hybrid and co-located configurations.

VI. Consensus and non-consensus items

Consensus:

[44] See SCE's tool, which is posted to the Energy Division's website at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/ra-reform-excel-workbooks/sce-slice-of-day-24-slice-model-20220921.xlsx

- Hybrid definition (single resource ID, single point of interconnection)
- Co-located definition (two resource IDs, single point of interconnection)
- ITC charging restriction treatment (updates for SOD framework)

Non-consensus:

- Deliverability status required for co-located resources *without* charging restrictions
- Deliverability status required for co-located resources *with* charging restrictions
- If the Commission were to allow for non-deliverable renewables to be counted for charging sufficiency, would the storage be limited by the charging capacity of the renewable resource? (e.g., it couldn't also count grid charging)

VII. Questions for parties

- Should full deliverability status be required for co-located resources *without* charging restrictions?
- Should full deliverability status be required for co-located resources *with* charging restrictions?
- If the Commission were to allow for non-deliverable renewables to be counted for charging sufficiency, would the storage be limited by the charging capacity of the renewable resource? (e.g., it couldn't also count grid charging)

VIII. References

Authors:

- **PG&E 8/10 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-3pge220810.pdf
- **CESA 8/10 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-3_cesa_220810.pdf
- **SEIA 8/10 Presentation:** https://www.cpuc.ca.gov/-/media/3d6658d8a0bf4e75b3e2d050fabcf4e1.ashx
- **CAISO 8/23 Presentation:** https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-history
- **SCE 8/10 Hybrid Configurations Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/ra-reform-excel-workbooks/sce-hybrid-configs.xlsx
- **SCE 8/3 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-3-2022-lse-compliance-tools/workshop-2_sce_220803.pdf

iv. Resource Counting for Storage

Authors: CESA

I. Background

Authors: CESA

In Decision (D.) 22-06-050, the Commission provided parties with significant direction regarding the treatment and counting of energy storage resources. Critically, D.22-06-050 concluded that storage resources will be assigned value based on Pmax or UCAP-light (if developed), restricted to daily resource capabilities (e.g., maximum daily run hours, maximum continuous energy, and storage efficiency). In addition, the Decision underscored that load-serving entities (LSEs) that utilize storage to meet their RA hourly capacity requirements must have excess hourly capacity in their showing to cover for the batteries needs, including efficiency losses. These elements, as well as the frameworks that will allow their utilization, were further refined through the workstream meetings. While direction was provided in D.22-06-050, some issues remained unresolved. These include the consideration of showing a storage asset operating at multiple cycles per day, as well as issues around the valuation of long-duration energy storage (LDES) and multi-day reliability events.

II. Issues

Authors: CESA

The key issues covered in this section are:

- Multi-cycle showings for energy storage.
- Long-duration energy storage (LDES) within SOD.

III. Presenters and Dates

Authors: CESA

- August 23, 2022:
  - CESA on LDES
- August 31, 2022:
  - Conversations surrounding multi-cycle showings for energy storage

IV. Proposal Summaries

a. CESA's Proposal on LDES

Authors: CESA

CESA underscored that, while the 24-hour nature of the SOD framework is an important and necessary step away from planning for a fraction of the day and towards meeting load in every single hour, paired with the inclusion of charging sufficiency verification, it creates complexities for the representation of LDES. The challenges are particularly important for those LDES assets with operational timeframes (*i.e.,* cycles) more than 24 hours. For example, assets with durations in excess of 10 hours may not complete a full charge/discharge cycle in 24 hours. Moreover, LDES can provide arbitrage across days or even weeks, something that is not captured fully in the 24-hour framework but has a significant impact on reliability.

As of the date of the presentation, CESA staff considers that energy storage resources with durations ≤ 10 hours are likely to be easily reflected within the proposed SoD paradigm. Nevertheless, resources with longer durations and those with operational timeframes above 24 hours (multi-day and/or seasonal storage) might prove more complex to represent. CESA staff considers that the key limitation regarding these assets relates to the charging sufficiency verification. A fundamental challenge is related to the fact that excess hourly capacity in a specific month might not be enough for assets with longer durations and lower efficiencies, assets whose competitive advantage is arbitrage over long periods of time and even across compliance showings.

To mitigate this concern, CESA proposes that, if an LSE has storage assets with an operational timeframe more than 24 hours, it should be able to make use of the "seasonal charging scheme." The seasonal charge scheme is a mechanism that would allow LSEs to take excess hourly capacity from one showing period to another. This captures the dynamic of moving spring-month overgeneration to provide charging sufficiency for energy storage assets shown in summer or winter months. This solution would allow for the carryover of excess energy to be used in future seasons (showings) for storage charging. In essence, this would not set a "use it or lose it" approach for excess generation and allow for "banking" of these RA attributes across different showing periods. While this would ease compliance with the charging sufficiency verification, notably, it would only be available to an LSE with storage assets that have an operational timeframe in excess of 24 hours. Thus, this mechanism creates the incentive for LSEs to procure these emerging technologies that bolster multi-day reliability while recognizing that they are specifically poised to provide weekly and even seasonal arbitrage.

b. CESA's Proposal on Multi-Day Reliability

Authors: CESA

During the August 23rd workshop, CESA noted that while capturing the likelihood of multi-day reliability events is better done through the IRP, the RA proceeding may need a framework that provides incentives for procurement of resources able to provide reliability across days. CESA's proposal regarding a seasonal charging scheme creates some positive incentives but does not establish any form of requirement. Previously, parties have suggested reflecting the need for some base level of capacity with availability above 4 hours to account for multi-day reliability events. As of the time of the presentation, CESA remained open to exploring this path.

CESA underscored that redefining the MCC buckets could reflect the need for some base level of LDES or firm generation to account for multi-day reliability events. Today, the CPUC limits the fraction of use- or energy-limited resources that may be used by an LSE to meet System RA through the MCC buckets. D.22-06-050 directed parties to ensure LDES resources are properly valued across the slice-of-day framework in coordination with the elimination of the MCC buckets. In that context, CESA suggested that similar to SCE's proposed Minimum Availability Categories, minimum requirements for assets with availability above 4 hours could be set to minimize multi-day reliability risks. Percentages could establish minimum, rather than maximum, caps by duration, and the durations could be consistent with MCC buckets today (24, 16, and 8 hours).

c. Multi-cycle Showings for Energy Storage

Authors: CESA

The issue of how to represent multiple storage cycles within the showing was discussed in the context of resource verification. This conversation involved consideration of the physical, contractual, and warranty limitations and conditions that different storage assets faced today. During the workstreams, parties asked about the possible limitations that would impede storage resources from providing multiple cycles within a 24-hour cycle. In response, parties noted that storage resources may face warranty conditions that limit them to a fixed number of cycles per day; nevertheless, these conditions are evolving, and the use of yearly cycles has increased.

Given these circumstances, parties discussed if these conditions represent a physical or contractual limitation, and how they could affect the expected provision of capacity by battery assets. SCE argued that the showing should represent what is being offered to the CAISO. Today, the warranty conditions do not govern what is offered into CAISO, thus, today RA storage assets can be and are dispatched in excess of one cycle per day. As such, these conditions cannot be considered physical limitations and storage assets should be able to be shown for multiple cycles per day. CESA agreed with SCE's position. Gridwell noted that older RA offers had one cycle/day and the resource tried to manage its dispatch through bids, not outage cards, so the limitations were market-based and not contractual.

d. Charging Sufficiency Verification Proposal

Authors: CESA

During the August 10 workshop, CESA presented a proposal to minimize the likelihood of individual LSEs failing their individual charging sufficiency verification checks due to lack of transactability even though the system might be, on a collective basis, sufficient. CESA's initial proposal noted that under the current formulation of the SOD paradigm, an LSE could fail its charging sufficiency verification due to the lack of excess hourly capacity within its portfolio, although the system as a whole could be sufficient. This issue is further exacerbated by the fact that the SOD framework lacks mechanisms that would allow for transactability that could cure such concerns. In this context, CESA put forth a proposal to establish an initial test to determine if charging sufficiency verification for standalone storage is warranted on an LSE-by-LSE basis. CESA's original concept, presented at the August 10 workshop, suggested to first estimate the energy output of all standalone energy-only (EO) variable energy resources (VERs) via the same exceedance methodology applicable to their RA-providing counterparts (i.e., those with Full Capacity Deliverability Status (FCDS)). Using this method, if the sum of said hourly output is expected to be enough to cover the charging needs of all standalone storage shown for RA, no further individual LSE charging sufficiency test would be needed. This would be a system-wide test, so no LSE would have to reveal its EO positions. If the sum of the expected hourly output is insufficient, a sufficiency test per LSE would be conducted. If this occurs, the individual test would need to be passed using RA-providing excess hourly capacity with FCDS above the hourly capacity requirements to charge the storage fleet.[45]

V. Comparison of the proposals

Authors: CESA

- CESA's Seasonal Charging Scheme.
    - If an LSE has storage assets with an operational timeframe in excess of 24 hours, it should be able to make use of a seasonal charging scheme.
    - The seasonal charge scheme is a mechanism that would allow LSEs to take excess hourly capacity from one showing period to another, allowing for carryover of excess energy to be used in future showings for storage charging.

[45] Note that CESA's original proposal was modified based on stakeholder input; the revised proposal is reflected in this section.

    - This mechanism creates the incentive for LSEs to procure these emerging technologies that bolster multi-day reliability while recognizing that they are specifically poised to provide weekly and even seasonal arbitrage.
- CESA's Multi-Day Reliability Proposal.
    - Similar to SCE's proposed Minimum Availability Categories, minimum requirements for assets with availability above 4 hours could be set to minimize multi-day reliability risks.
    - Percentages could establish minimum, rather than maximum, caps by duration, and the durations could be consistent with MCC buckets today (24, 16, and 8 hours).
- Multi-cycle showings for energy storage.
    - SCE argued that the showing should represent what is being offered to the CAISO.
    - Since, today, warranty conditions do not govern what is offered into CAISO, RA storage assets can be and are dispatched in excess of one cycle per day.
    - Thus, storage assets should be able to perform multiple cycles per day.
- Charging Sufficiency Verification Proposal.
    - A system-wide test using energy-only resources should be conducted in order to determine if each LSE needs to show charging capacity.

VI. Questions for parties

- Do you agree with SCE's and CESA's argument that storage assets should be able to perform multiple cycles per day given that they are already dispatched in excess of one cycle by CAISO?
- Is there still contractual language that needs to be reviewed by Energy Division to confirm a storage resource can be shown for multiple cycles?
- Are there other issues or modifications that must be addressed to properly represent LDES assets?

VII. References

- CESA 8/23 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-23-2022-planning-reserve-margin/workshop-5_cesa_220823.pdf

v. Resource Counting for UCAP-light

Authors: IEP

I. Background

Currently, thermal resources' capacity values are based on their installed nameplate capacities. However, some facilities' NQC values may be lower than their nameplate capacities due to deliverability constraints on the transmission system or due to voluntary derates to account for ambient temperature effects in the summer. Because thermal facilities' resource counting values do not generally reflect forced outages and ambient temperature effects, the PRM is higher than it would otherwise be to account for the additional resources needed to cover these outages. Some parties have argued that including thermal resources' forced outages in the PRM rather than in thermal plants' own NQCs overcounts thermal resources' contributions to reliability. These parties believe that some reform is needed to decrease thermal facilities' capacity values to convey more accurate signals to LSEs about thermal facilities' reliability contributions.

During the RA reform workshops that preceded D.22-06-050, CAISO proposed that the Commission adopt an Unforced Capacity (UCAP) resource counting methodology for thermal resources, a methodology that reduces thermal generating facilities' NQCs based on past performance. Under CAISO's proposal, each facility would be assigned a Seasonal Average Availability Factor (SAAF) equivalent to 1 minus the sum of reported forced and urgent outages for each hour in which the RA supply cushion was at or below a pre-defined threshold. Ambient temperature derates, which are reported as a type of forced outage, would count against the SAAF. Hours during which a plant is offline for a planned outage or during which a plant's output wasn't deliverable due to transmission limitations would not count against a plant's SAAF. In D.22-06-050 the Commission deferred consideration of UCAP to a later phase of the proceeding due to "the breadth of issues of outstanding issues to develop prior to initial implementation of the 24-hour framework…."[46]

As an alternative to a full UCAP approach, some parties proposed a "UCAP-light" alternative that would only account for ambient derate effects. The Commission noted that while UCAP-light had been discussed at the RA workshops "at a conceptual level, no detailed methodology has been proposed."[47] The Commission expressed interest in adopting a UCAP-light mechanism and encouraged parties "to attempt to establish a UCAP-light mechanism to apply to dispatchable resources as part of the workstreams identified in Section 4.7." [48]

II. Issues

- Should SOD include a UCAP-light treatment for dispatchable resources?

III. Presenters and Dates

- August 17, 2022:
    - IEP

IV. Proposal Summaries

a. IEP

As context for development of its proposal, IEP noted that the analysis was limited to illustrative examples using data from only three days of data from four powerplants because the format and available fields in CAISO's outage data make more extensive analysis infeasible.[49] There are numerous obstacles to using this data source as the basis of more systematic analysis of all thermal plants. Generators can report an individual outage, which appears as one row of data on the outage spreadsheet, of any duration, with any start time and ending time. Most plants consistently report hourly derates starting at the top of every hour. However, some plants routinely report ambient derates that start or end intra-hourly or report a multi-hour derate that shows as one record in the spreadsheet. For example, on July 9, 2021, Marsh Landing 1 reported hourly outage data at the beginning of every hour until 11 pm, at which point it reported one outage from 11:00 pm to 11:04 pm and the same outage amount from 11:04 pm through the end of the day. Because the reported ambient derate value didn't change, IEP combined the two data points into a single one-hour block to facilitate

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[46] D.22-06-050, at 99.
[47] D.22-06-050, at 84.
[48] D.22-06-050, at 84-85.
[49] CAISO. "Curtailed and non-operational generators in California and neighboring balancing authorities." https://www.caiso.com/market/Pages/OutageManagement/CurtailedandNonOperationalGenerators.aspx

the analysis. Midway Peaking reported hourly outages until 5 am, at which point it reported its derate as one three-hour block from 5 am to 8 am. This outage had to be manually disaggregated into three one-hour blocks to be consistent with the other plants and to allow for calculation of hourly availability factors. Disaggregating a multi-hour derate would be particularly important if the derate spans a period that falls within tight supply cushion hours and a period that does not. Thus, considerable effort is required to put the data into a consistent hourly format.

Another complication to the data analysis is that the data are posted daily in individual spreadsheets. Either a sophisticated data query that pulls daily outage reports and combines the data in a usable format will be needed to enable analysis of all days with tight supply cushions or the spreadsheets would need to be aggregated manually. Additionally, some columns in the daily spreadsheets are merged, necessitating manual unmerging so that data filtering and sorting can function.

For its proposal, IEP chose gas-fired power plants representing a mix of several characteristics: one is located in a relatively cool climate zone while the other three are in hot climate zones; one plant includes both foggers and evaporative inlet chillers to boost production during high temperatures; and two plants are combined-cycle facilities while the other two are simple-cycle units. For each of these four plants, IEP analyzed only one category of reported outage, "Ambient Due to Temp," from CAISO's daily reports on curtailed and non-operational generators on three days: a winter day (January 5, 2022), an average summer day (July 16, 2021) and a very hot summer day (July 9, 2021). The table below provides the name and locations of the plants used for the analysis as well as their NQCs (with different summer and winter NQCs shown as applicable), and their Pmax ratings.

Table 9: Plants Included in Analysis

Plant	Location	NQC Sum/Win	Pmax
Marsh Landing #1	Antioch, CA	191/203	204
La Paloma #1	Kern County	260	267
Midway Peaking	Fresno County	108/120	120
Desert Star Energy Center	Searchlight, NV	419	495

For each plant, IEP calculated hourly availability factors two ways: as one minus the reported ambient derate divided by the plant's NQC and as one minus the reported ambient derate divided by the plant's Pmax. When dividing by the NQC, IEP capped the values at 100% of NQC so that the resulting values wouldn't exceed the NQC. During the workshop, IEP presented the data using the NQC basis, but after receiving further clarification from CAISO staff, IEP has determined that it is more appropriate to show the values in reference to the Pmax values. This is because plants with NQCs significantly below their Pmax ratings may often have available capacity above their NQC ratings. Additionally, some plants, like Marsh Landing #1 and Midway Peaking, derate their own NQCs in the summer. As a result, the summer and winter availability factors are not directly comparable because the denominators differ.

CAISO presented its UCAP proposal with the assumption that thermal plants would have one NQC value that would apply to all hours of an LSE's 24-slice showing. IEP calculated a similar illustrative fixed

UCAP-light value for summer and winter, using the representative days from January and July. Because IEP did not have easy access to the data needed to determine the hours with the tightest RA supply cushions, IEP averaged the availability factors during the net peak hours of 4 pm to 9 pm as a proxy for hours with tight supply conditions to calculate the single UCAP-light capacity factor.

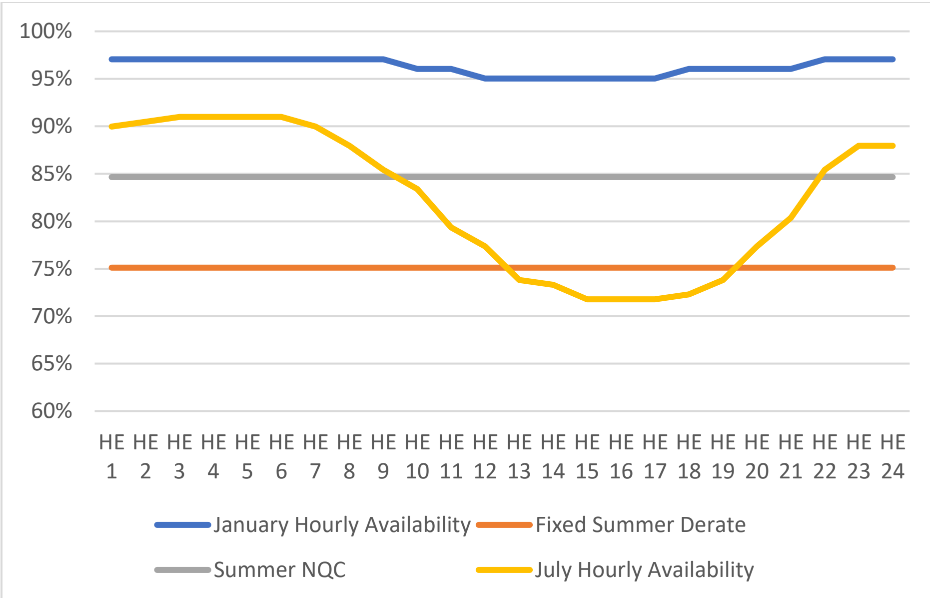
Table 10: Illustrative UCAP-Light Values

Plant	Summer UCAP-light	Winter UCAP-light
Marsh Landing #1	94.3%	97.4%
La Paloma #1	95.3%	96.2%
Midway Peaking	90.0%	99.0%
Desert Star Energy Center	75.1%	95.8%

The fixed UCAP-light derate for Desert Star Energy Center is about 75 percent of Pmax, well below the NQC value listed by the plant, which is 85 percent of Pmax. The large gap between the illustrative UCAP-light derate IEP calculated and the facility's NQC is likely driven by the fact that only two days' worth of data were used to derive the results, and one of those days was among the hottest of 2021. A UCAP-light approach using more data would probably have yielded a larger available capacity.

When IEP examined the hourly pattern in facilities' ambient derates, one plant demonstrated large swings in the capacity offered during the daytime and nighttime hours. The chart below shows Desert Star Energy Center's illustrative hourly availability factors for July and January, the facility's NQC, and the summer fixed derate factor using only the average available capacity from 4 pm to 9 pm. The chart shows that from midnight until about 9 am in July, the plant was able to deliver more than its full NQC value. Output quickly dropped from 9 am until about 2 pm, at which point it was only able to offer 72 percent of its Pmax value in the market. From 6 pm on, its output increased, and it was able to return to its full NQC by 9 pm.

Figure 51: Hourly Pattern of Facilities' Ambient Derates



Due to this pronounced diurnal pattern in some inland plants' generation profiles, IEP suggested that if UCAP-light were adopted, generators should have the option of offering their capacity using either the fixed derated value or an hourly capacity value, similar to the exceedance profiles being developed for wind and solar resources. The higher availability factors in the evening and morning hours could provide additional value to LSEs as a complement to the profile of solar resources in their portfolios. Whether the fixed UCAP-light approach is used or the plant's existing NQC, a flat derated capacity value would undervalue Desert Star Energy Center's available capacity during many hours of the day.

V. Questions for parties

IEP has concluded that it is infeasible to develop a UCAP-light resource counting process using CAISO's outage data in its current format. Unless the CAISO data can be provided in a manner that allows users to query data for multiple days and presents the data in a consistent hourly format, a wholly different approach will be necessary. Implementing UCAP-light in California may necessitate an engineering estimate approach similar to the adjustments the New York ISO (NYISO) makes in its resource capability testing protocols to correct for ambient temperature effects.[50] Alternatively, data from the Generating Availability Data System may be more conducive to the type of analysis required to systematically produce UCAP-light availability factors for all thermal plants providing RA to CAISO. Neither of these options has been discussed in the workshop process, and it is implausible to develop them in time for near-term adoption by the Commission.

Questions:

- Is it worth continuing to pursue UCAP-light or should parties focus their efforts on a more comprehensive UCAP methodology?

[50] NYISO, 2022. "Resource Capability Testing: Amount of Capacity Available," slides 22-26. https://www.nyiso.com/documents/20142/3036383/Resource-Capability.pdf/ee932c12-61bd-f38e-bfa6-f6e873e5c2af

- It would also be helpful for parties to comment on whether the development of hourly availability profiles instead of or in addition to fixed derate factors would provide enough value to LSEs to warrant further work on that alternative.

VI. References

- **IEP 8/17 Presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2022-planning-reserve-margin/workshop-4_iep_220817.pdf

vi. Resource Counting for DR

Authors: CLECA

I. Background

Authors: CLECA

QC for DR has historically been based on the use of the Load Impact Protocols (LIP). The LIP require standardized hourly outputs of demand reductions for actual events under the conditions they were dispatched, known as ex-post load impacts. They also require impacts for each of the 24 hours and for each month under 1-in-2 and 1-in-10 monthly peaking conditions, known as ex-ante load impacts. The LIP use ex post data to determine the load reductions associated with DR resources based on regression analysis and adjust for standardized weather to forecast ex ante load impacts. For forecasting the QC, the number of enrollments is a forecast, which is more uncertain for newer programs than it is for well-established programs.

The Commission separately directed parties to consider whether the planning reserve margin (PRM) adjustment that had been used to adjust the QC should again be used (it has previously reduced the PRM factor to eliminate reserves) and whether the Transmission Loss Factor (TLF) and the Distribution Loss Factor (DLF) should be retained.[51]

II. Issues

Authors: CLECA

The main issues for DR are:

1. How to represent DR in the 24-hourly Slice of Day (SOD) framework.
2. How to address the full hours of availability for DR resources.
3. How to address the time lag inherent in the use of historical data in the LIP.
4. How to reflect the temperature-sensitivity of some DR programs, so that the hourly QC recognizes that the DR response is not the same for all hours called.

[51] D. 22-06-050 at 40.

5. How to address spillover effects outside the window of time when the resource is dispatched, such as pre-cooling (load increase before event), snapback (load increase after the event), and reduced load after the event as industrial processes are turned back on.
6. The use of adders to adjust the DR QC for the PRM, DLF, and TLF.

III. Presenters and Dates

Authors: CLECA

The issue of QC for DR was addressed at a 9/16/22 workshop facilitated by the CPUC's Energy Division pursuant to a ruling in R.21-10-002[52] and at the September 29, RA Reform working group meeting. For the 9/16/22 workshop, which was facilitated by the Energy Division, Ordering Paragraphs 2 and 3 of D.22-08-039 asked parties to address the following:

1. The hours in which DR resources can be shown and whether those hours must be consecutive
2. Whether the transmission and planning reserve margin adders should be applied
3. Whether or not the value of DR resources can vary by hour
4. Whether, and if so, how, snap back effects should be accounted for.

There were 4 presentations at the 9/16/22 workshop. The Energy Division, Demand Side Analytics (sponsored by SDG&E), the utilities, and CLECA all made presentations. The workshop was focused on QC for DR for the RA Reform test year 2024 and addressed the questions posed by D.22-08-039. These issues were also discussed at the 9/29/22 RA Reform working group meeting in a presentation by SCE. All the proposals are based on continued use of the results of the LIP. They differ in their treatment of the use of the 24-hourly data from the LIP for DR QC for each hour of the SOD framework.

IV. Proposal Summaries

Table 11: Summary of DR Counting Proposals

Party	Proposal Summary
Energy Division	Proposed four (4) showing options: 1. Variable across all hours (identical to LIP) 2. Variable but cap at avg. 4 worst consecutive hours in AAH 3. Variable, any 4 hours from LIP 4. Single value, min. 4 consecutive hours within AAH
PG&E and-SDG&E	Propose: 1. DR should comply with the minimum RA requirements and the resource's hourly impacts should reflect its daily use limitations (e.g., maximum event duration). Hours can be either consecutive or non-consecutive (if the program rules allow).

[52] D. 22-08-039 at 11 and OP 2 and 3.

Party	Proposal Summary
	2. Value of DR resources should vary by hour, as DR is a variable resource. 3. Pre-cooling and snapback effects should be accounted for on an hourly basis, corresponding to the event window used in (1) above. 4. Retain the transmission and distribution (T&D) line loss adders for DR while eliminating the PRM adders for DR.
SCE	On one hand, DR resources with impactful spillover effects would have a 24-hour profile with a pre-determined call window. Length of the call window would be determined by programs rules per the tariff schedule and would encompass four consecutive hours of the Availability Assessment Hour (AAH) window from 4-9 PM. For instance, if the program can be called from 3-9 pm for a maximum of six hours per day per service account, the window would be from 3-9 pm. Any spillover effects before and after the call window would also be shown. DR resources without impactful spillover effects, on the other hand, would be shown, based on factors such as the LSE's own load shape, RA minimum requirements to maximize the resource's contributions to system reliability needs, program rules, and tariff schedules. Only the Forced Outage component of the Planning Reserve Margin (PRM) adder should be retained. DR QC does not necessarily contribute to reducing the load forecast error. However, the purpose of applying the Load Forecast Error adder to DR load reductions -- capturing DR performance due to variability in real-time load and the 1-in-2 monthly load forecast under extreme conditions -- could be better reflected by using DR load reductions under the 1-in-10 weather scenario to inform DR QC values for future RA Compliance Years. The transmission and distribution adders (TLF and DLF) should also be retained. Note that whichever adders are applied to the supply-side must also be applied to the load-modifying side.
DSA-CLECA	1. Support use of the LIP outputs for the 24-hour Slice-of-Day framework since they already produce hourly impacts for monthly peak conditions 2. Include snapback and spill-over effects whether positive or negative. 3. Allow DR QC to show the full duration of DR resource capability if it exceeds the AAH. For example, a six-hour resource should be able to show for six hours. 4. Require a summary of 24-hour Slice-of-Day resources in 12-month by 24-hour table. 5. DR should comply with the minimum RA requirements for DR. That is DR would need to show four hours between 4-9 pm and meet the requirements for monthly and annual hours of availability. 6. CLECA took position on the T&D and PRM adders. DSA did not take a position on the PRM adder.

Table 12: Summary of Positions on Key Issues Related to DR Counting

#	Component	ED	PGE-SDG&E	SCE	DSA-CLECA
1	Can DR resources QC vary by hour?	Possibly, must balance with complexity	Yes	Yes	Yes
2	Support use of load impact protocol outputs for 2024?	Yes	Yes	Yes	Yes
3	Propose modification to the Load Impact Protocols?	No	Yes, partial modifications	Yes to accommodate SOD	Yes, but minor
4	Do DR planning weather conditions (1-in-2 and 1-in-10 monthly) need to be updated to reflect the worst-day of the month as defined by RA?	No	No, if the planning weather conditions are the same as the 1-in-2 peak.	No. DR planning weather conditions to be same as that for load forecasting (i.e., 1-in-2)	No, if the worst 1-in-2 day is used for the month.
5	Should DR QC be allowed to show outside the AAH window if the resource can deliver for a longer period than the AAH?	Yes	Yes	Yes	Yes
6	Once DR QC is certified for specific hours does it remain static, or can it be modified?	Static	Static	Static, until updates are certified	Static
7	Should snapback/spillover effects be included?	Some options include them	Yes	Yes	Yes, both positive and negative should be included
8	Should the minimum requirements for DR QC be kept?	Yes	Yes	Yes	Yes
9	Should a RA summary table of DR QC resources by month and hour be required?		Yes	Yes	Yes
10	Should T&D adders be applied to DR QC?	Yes	Yes	Yes	Yes
11	Should any components of the PRM be included and, if so, which?	Include for test year	No, eliminate all components of	Forced Outage	CLECA supports including all

#	Component	ED	PGE-SDG&E	SCE	DSA-CLECA
			the PRM for DR		components. DSA did not take a position.

a. ED

Authors: Energy Division staff

ED staff presented a range of options for DR counting methodologies for the 2024 test year. This was not intended to be an exhaustive list, but rather to stimulate a conversation about the advantages and disadvantages of different methodologies. The four options presented were:

1. Variable across all hours, i.e., identical to the outputs of the Load Impact Protocols (LIP)
2. Variable but cap at average across four worst consecutive hours in the Availability Assessment Hours (AAH)
3. Variable, any four hours from LIP (consecutive or non-consecutive)
4. Single value, minimum of any four consecutive hours within AAHs
    a. Derated value if less than four hours of positive load impact (proportional to number of missing hours)
    b. Zero value if less than four hours of positive load impact

In options 2-4, DR resources could potentially be shown for more than four hours if longer dispatches were required by contract or tariff (e.g., resources enrolled in the Base Interruptible Program). The following table identifies key pros and cons of the four options identified by ED staff.

Table 13: Comparison of DR counting options for 2024 test year prepared by ED

#	Option	Pros	Cons
1	**Variable across all hours (identical to LIP)**	• Most flexibility for LSEs/DRPs • Accounts for snap back	• Complicated to implement/validate • No enforcement of 4-hour availability, reliability concerns • Likely significantly overstates available capacity over 24-hr period
2	**Variable but cap at avg. 4 worst consecutive hours in AAH**	• Some enforcement of 4-hour availability • Accounts for snap back	• Complicated to implement/validate • Reliability concerns • Likely significantly overstates available capacity over 24-hr period
3	**Variable, any 4 hours from LIP**	• Enforces 4-hour availability (non-consecutive) • More flexibility	• Complicated to implement/validate • Reliability concerns • Does not account for snap back • Many resources cannot dispatch multiple times per day, may not align with master file program design and/or contract capabilities

4	**Single value, min. 4 consecutive hours within AAH**	• Enforces 4-hour availability (consecutive) • Simplest to implement/validate • Fewest reliability concerns, esp. if QC = 0 for <4 hours	• Does not account for snap back

Finally, ED staff proposed retaining the forced outage/forecast error component of the PRM adder, the distribution loss factor adder, and the transmission loss factor adder for the 2024 test year while awaiting a recommendation from the California Energy Commission (CEC) DR working group on whether to retain the adders for 2025 and beyond (Table 14). Even though the PRM is increasing to at least 17% in 2024, ED staff proposed keeping the PRM adder at 9%. The Commission previously supported removing the forecast error component of the PRM adder, but since there is currently no consensus on how much can be attributed to forced outages vs. forecast error, the Commission decided to retain the full 9% adder until more information was available. Therefore, given the fact that the 9% adder is already overestimating the forced outage component, increasing the PRM adder seems questionable at this time.

Table 14: Demand response adders proposed by ED staff for 2024 test year

Adder	Action	Value (PG&E)	Value (SCE)	Value (SDG&E)
PRM – Operating Reserves	6% Removed by D.21-06-029	N/A		
PRM – Forecast Error & Forced Outages	**Retain**	**9%** (same for all IOUs)		
Distribution Loss Factor	**Retain**	**6.7%**	**5.1%**	**7.1%**
Transmission Loss Factor	**Retain**	**3.0%**	**2.5%**	**2.5%**

b. SCE

Authors: SCE

Ordering Paragraphs (OP) 2 and 3 of Decision (D.) 22-08-039 seek proposals regarding the following:

- **The hours in which demand response resources can be shown and whether consecutive.**

For DR resources with impactful spillover effects, there would be a profile shape due to a pre-determined call window. All 24 hours of the resource's profile would be shown. The length of call window would be determined by program rules per the tariff schedule. It would also encompass four consecutive hours in the Availability Assessment Hours (AAH) of 4-9 pm. For instance, Summer Discount Plan, which can be called anytime from 11 am-8 pm on weekdays for a maximum of six hours per day per service account, the window would be from 2-8 pm. Any four-hour resource with spillover would be shown from either 4-8 pm or 5-9 pm, depending on the month.[53] A six-hour resource that can be available 24/7 (i.e., API, BIP) would be shown across AAH, with showing of the additional hour to be worked out with the Energy Division. Any pre-cooling and spillover effects associated before and after the call window would also be shown.

For DR resources without impactful spillover effects, the load-serving entity (LSE) would determine which of the limited hours to show, taking into consideration factors such as the LSE's own load shape, RA minimum requirements to maximize DR resources' contributions to system reliability needs, program rules, and tariff schedules.

- **Whether the transmission and planning reserve margin adders should be applied.**

The transmission and distribution reserve margin adders should be applied to the ex ante load impacts. Load impacts are assessed behind-the-meter. CEC's load forecasts used for determining RA requirements, however, are assessed at the transmission level. To make sure that load impacts from supply-side DR resources are assessed on the same level as that of CEC's load forecasts, transmission and distribution planning reserve margin adders should be applied.

- **Whether or not the value of demand response resources can vary by hour.**

The capacity value of DR resources can vary by hour since DR is a variable resource. One example of capacity values varying by hour would be that of weather-sensitive resources. Estimated load reductions in the second hour can be less than that of the first hour due to participants' overriding the event called.

- **Whether, and if so, how, snap back effects should be accounted for.**

Any kind of spillover effects, if impactful and statistically significant, should be shown, even if outside of the call window to show how DR resources actually behave.

- **Whether any components of the Planning Reserve Margin (PRM) adders should be applied.**
    - **Ancillary Services (A/S)**
        - If CAISO procures most of A/S in the day-ahead market (DAM), while most DR programs operate in the real-time market (RTM), then DR resources may not contribute to reducing CAISO's procurement of A/S in the DAM. In that case, the A/S component of PRM should not be applied to estimated DR load reductions from the ex ante.
    - **Load Forecast Error**
        - SCE recommends removal of the Load Forecast Error adder to DR load reductions from ex ante. DR QC does not necessarily contribute to reducing the load forecast error. However, the purpose of applying the Load Forecast Error adder to DR load reductions -- capturing DR performance due to variability in real-time load and the 1-in-2 monthly load forecast under extreme conditions -- could be better

[53] Beginning in the 2023 RA compliance year, the CPUC's RA measurement hours are 5-10 pm for March and April. CPUC. 3.2 2023 Flexible Capacity Requirements. "Decision Adopting Local Capacity Obligations for 2023 – 2025, Flexible Capacity Obligations for 2023, and Reform Track Framework." Decision (D.) 22-06-050. pp. 14-15.

reflected by using DR load reductions under the 1-in-10 weather scenario to inform DR QC values for future RA Compliance Years.

- **Forced Outages**
  - SCE recommends retaining the Forced Outage Adder if the LIP remain the methodology for estimating load reductions by DR to inform DR QC values for future RA Compliance Years. The ex post values already account for load reductions due to forced outages in the prior period. They are used to estimate ex ante DR load reductions, which are used to inform DR QC values for future RA Compliance Years. Not applying the Forced Outage Adder would discount DR QC for forced outages twice. The Forced Outage Adder applied should be the same as that from LOLE/LOLP modeling (currently approximately 5.0 – 7.5%). It is also noteworthy to point out that whichever PRM adder is applied to the QC of supply-side demand response (SSDR) resources, the same would also have to be applied to load-modifying QC, which is used to reduce load forecasts, including that from CEC's *Integrated Energy Policy Report*. Otherwise, there would be an imbalance between forecasted capacity and load.

c. PG&E and SDG&E

Authors: PG&E and SDG&E

Modifications for 2024 Test Year

Pursuant to Ordering Paragraph 2 of Decision 22-08-039, parties are invited to make proposals to address the following issues:

- The hours in which DR resources can be shown and whether those hours must be consecutive;
- Whether the transmission and planning reserve margin adders should be applied;
- Whether or not the value of DR resources can vary by hour; and,
- Whether, and if so, how, snap back effects should be accounted for.

SDG&E's and PG&E's positions on the four issues are described below

- *The hours in which DR resources can be shown and whether those hours must be consecutive*.

There are certain minimum RA requirements for DR. Currently, for a DR resource to be qualified for RA, it must be available Monday through Saturday for four (4) consecutive hours between 4pm and 9pm, and for at least 24 hours each month from May to September.

<u>SDG&E's position</u>: SDG&E agrees that its DR should comply with the minimum RA requirements which is currently 4pm-9pm. Additionally, the resource needs to be available for four consecutive hours. However, SDG&E also believes that it may be possible that a DR program is designed to be dispatched over the course of a day for a longer period i.e., 6 hours, the hours might be consecutive or non-consecutive hours. If the DR program is designed in a way that can be triggered multiple times a day, then flexibility should be allowed and the hours do not need to be consecutive.

PG&E's position: DR should comply with the minimum RA requirements, including the availability assessment hours (AAH), and be allowed to be shown for additional hours where the resource is available. The additional hours should reflect the program rules (e.g., maximum dispatchable hours per day) and the hours do not necessarily need to be consecutive if the program rules allow multiple events in a given day. For example, a resource with a six-hour maximum duration should show a 24-hour load impact profile to reflect pre-cooling effects (if any) for each hour preceding the dispatch, hourly impacts during the dispatch, and spillover effects (if any) for each hour following the dispatch.

- *Whether or not the value of DR resources can vary by hour.*

SDG&E's position: The DR resources should be allowed to vary by hour because DR is not a fixed resource, it is a variable resource. For example, if the program is available to be called in a 9-hour window, its typical for some programs' Load Impacts to be larger during the first hour of the event than the following event hours. SDG&E believes that this is also consistent with the SoD framework.

PG&E's position: The value of DR resources should be allowed to vary by hour because DR is a time-varying resource. Showing the variable nature of the DR is compatible with the slice-of-day framework.

- *Whether, and if so, how, snap back effects should be accounted for.*

SDG&E's position: Precooling and snap back effect should be accounted for. Show the event window within RA assessment hours (HE17-HE21), where precooling hour will be at HE16 and snap back at HE22. If the precooling and snap back hours are outside of the RA window SDG&E should not get penalized.

PG&E's position: Pre-cooling and snapback effects corresponding to the dispatch hours should be accounted for, where the dispatch hours are pre-defined by the resource provider.

- *Whether the transmission and planning reserve margin adders should be applied.*

SDG&E's position: Operating reserves (6%) and forced outage and forecasting error adders (9%) should be removed. Distribution and Transmission Losses should be retained. According to Decision 21-06-029 OP12 (page 78), "the 6% component of the planning reserve margin (PRM) adder associated with ancillary services and operating reserves shall be removed for demand response resources. This is effective for the 2022 Resource Adequacy compliance year. The 9% component of the PRM adder associated with forced outages and forecast error shall be retained." However, SDG&E recommends that both the 6% operating reserves and the 9% error adders be removed.

PG&E's position: DR should retain the adders for transmission and distribution (T&D) but eliminate all planning reserve margin (PRM) adders. The PRM adders should be removed for

DR because, 1)the adder for operating reserves/ancillary services (OR/AS) should be zero because DR resources do not reduce the need for operating reserves in the real-time market; 2) DR is a variable output resource, for which a buffer or a planning reserve is needed to offset the variability of the resource; and 3) DR variability includes uncertainties due to forecasting error and forced outages—in fact, the difference between the two uncertainties is not well defined in the DR context.

d. Demand Side Analytics and CLECA

Authors: Demand Side Analytics and CLECA

CPUC Resource Adequacy Demand Response – DSA and CLECA Presentations

Both the DSA and CLECA[54] presentations focused on what outputs are currently produced as part of the load impact protocols (LIP) and the modifications needed to align with the 24-hour slice-of-day RA framework.

The objective of the 24-hourly slice-of-day framework is to recognize that the capability of resources varies on an hour-by-hour basis and is not a constant value over the day or month. DR resources include a wide range of technologies and customer segments. They can vary in shape, weather sensitivity, and operating limitations such as the maximum event duration, annual hours of dispatch, and the number of consecutive dispatch days. Moreover, some resources have spillover effects outside the dispatch window such as pre-cooling, snapback, or load reduction persistence. For some DR resources such as thermostat programs, the performance depends on the duration of the event; i.e., the load reduction differs between the first hour of dispatch and the fourth hour of dispatch. For others, such as the base interruptible program, industrial customers' load reductions vary far less over the event period.

Current Outputs Produced for Demand Response (Ex ante and Ex post)

The current LIP process requires standardized hourly outputs of demand reductions for actual events (ex-post) and standardized hourly load reduction capability under planning conditions (ex-ante).

Ex-post impacts reflect the reductions delivered when resources are called, given the conditions at the time and the share of resources dispatched. Actual conditions do not necessarily match planning conditions. In practice, DR resources are often available for more hours than the availability assessment hours (4-9 pm or 5-10 pm) and can be dispatched outside those hours, for longer or shorter durations than the 4 hours required for resource adequacy, and under different conditions than a 1-in-2 weather year.[55] In addition, DR resources are dispatched for a number of reasons – e.g., economic dispatch, reliability, and testing – and not all resources are dispatched for each event. They differ from CAISO settlements which typically use easy-to-understand but less accurate day-matching baseline heuristics.

[54] CLECA in the prior RA reform working group report (pp 69-72) recommended the use of hourly profiles that are created in the LIP.

[55] While the planning process assumes DR response based upon a 1-in-2 weather condition, it is expected DR would be called during hotter conditions. For weather-sensitive programs, the load reduction would be higher than the planning assumption.

The LIP require producing hourly results (24 hours) for each event in a standardized format, including information about the number of participants called, event start and end times, weather conditions, and confidence intervals. Figure 52shows the ex-post output table for SCE's SDP residential program for the annual peak in 2020, August 18, 2020. All the program resources were dispatched from 1:40 pm to 7:48 pm on a day, August 18, 2022, where weather conditions exceeded 1-in-2 peak conditions. Ex-post load impacts for all programs and all events have been recorded using the same output template since 2008, providing a rich history of historical performance under a wide range of conditions. The ex post results are used as the basis to inform the development of the ex ante load impacts.

Figure 52: Example of Ex-Post Tables

Southern California Edison

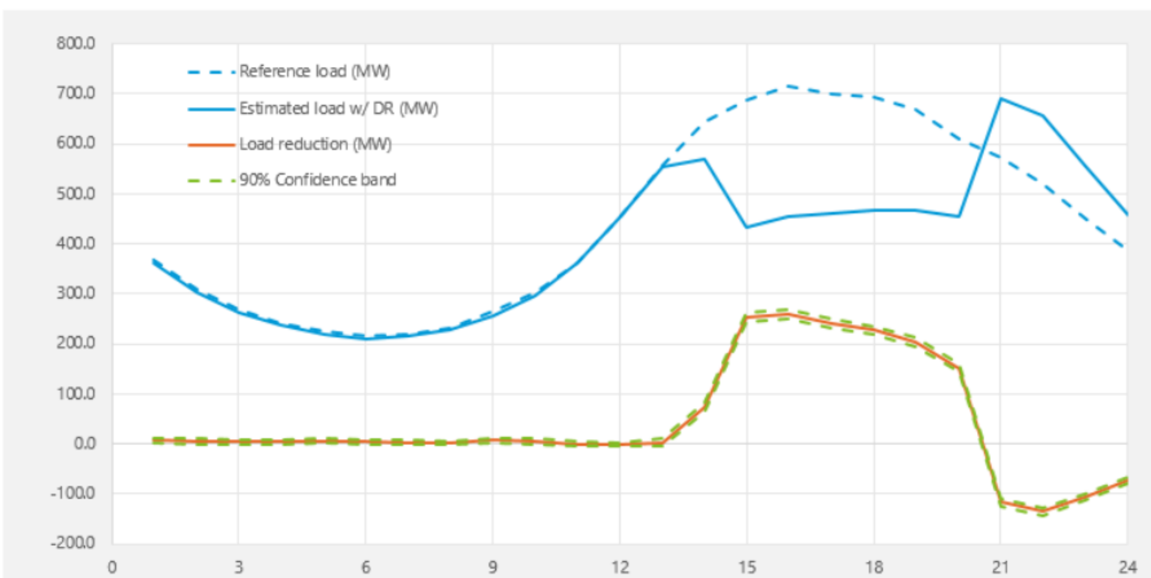
2020 Ex Post Load Impacts - TD Programs

Table 1: Menu options

Program	SDP-R
Type of result	Aggregate
Category	ALL
Subcategory	All
Event date and hours	2020-08-18 (13:40-19:48 PM)

Table 2: Event day information

Event start	1:40 PM
Event end	7:48 PM
Total sites	199,557
Total devices	232,734
Total AC tonnage	846,367
Event window temperature (F)	100.6
Full event hours load reduction (MW)	236.82
Full event hours % load reduction	34.2%
All event hours load reduction (MW)	201.29
All event hours % load reduction	29.9%



Hour ending	Reference load (MW)	Estimate d load w/ DR (MW)	Load reduction (MW)	% Load reduction	Avg temp (F, site weighted)	Uncertainty adjusted impact - Percentiles 5th	95th	Std. error	T-statistic
1	367.43	360.50	6.93	1.9%	82.03	0.87	12.99	3.68	1.88
2	309.42	304.00	5.42	1.8%	80.85	-0.09	10.92	3.35	1.62
3	268.75	263.89	4.85	1.8%	79.91	-0.06	9.77	2.99	1.62
4	241.34	236.43	4.90	2.0%	78.86	0.51	9.30	2.67	1.84
5	224.46	217.72	6.74	3.0%	77.74	3.08	10.41	2.23	3.03
6	214.65	210.65	4.00	1.9%	76.93	0.55	7.45	2.10	1.91
7	218.21	214.71	3.50	1.6%	76.54	0.09	6.91	2.07	1.69
8	231.63	228.79	2.83	1.2%	76.36	-1.11	6.78	2.40	1.18
9	264.30	256.54	7.77	2.9%	76.27	2.84	12.69	2.99	2.59
10	302.48	296.85	5.63	1.9%	78.31	0.23	11.02	3.28	1.72
11	362.18	361.54	0.64	0.2%	83.13	-3.27	4.55	2.38	0.27
12	451.59	452.23	-0.64	-0.1%	88.85	-4.55	3.27	2.38	-0.27
13	556.08	552.48	3.60	0.6%	93.73	-4.31	11.51	4.81	0.75
14	643.39	570.51	72.89	11.3%	97.47	64.47	81.30	5.11	14.25
15	685.85	432.43	253.43	37.0%	101.13	244.52	262.34	5.42	46.78
16	713.48	453.87	259.61	36.4%	101.79	250.37	268.85	5.62	46.21
17	700.20	459.69	240.50	34.3%	102.56	230.83	250.18	5.88	40.89
18	692.66	465.69	226.97	32.8%	100.00	217.89	236.06	5.52	41.09
19	669.46	465.87	203.59	30.4%	97.36	195.43	211.75	4.96	41.06
20	608.10	456.08	152.02	25.0%	94.97	143.84	160.19	4.97	30.59
21	572.36	689.30	-116.94	-20.4%	91.93	-124.62	-109.26	4.67	-25.04
22	519.66	655.21	-135.55	-26.1%	87.98	-143.28	-127.82	4.70	-28.83
23	451.22	557.60	-106.37	-23.6%	85.33	-113.81	-98.93	4.52	-23.53
24	385.11	457.05	-71.94	-18.7%	83.61	-78.32	-65.56	3.88	-18.55
Daily	Reference load (MWh)	Estimate d load w/ DR (MWh)	Energy savings (MWh)	% Change	Avg. Daily Weighted temp (F)	Uncertainty adjusted impact - Percentiles 5th	95th	Std. error	T-statistic
Daily kWh	10654.01	9619.63	1034.38	10.8%	87.24	1001.68	1067.08	19.88	52.03

In addition, the LIP require outputs by hour and month that align with planning conditions, known as ex-ante impacts. The ex-ante impacts are based on actual historical performance and typically include all events for the most recent three (3) years. While the CPUC does not use hourly results for RA qualifying capacity, all DR programs have been producing hourly results under planning conditions since 2008. The existing ex-ante impacts factor in weather sensitivity, load shapes, spillover effects (including pre-cooling, snapback, and decay across the event window), and event decay (when performance is affected by the event duration). They are produced in aggregate (MW) and on a per-customer basis for IOU-specific and CAISO 1-in-2 and 1-in-10 monthly peaking conditions. The impacts are standardized to show reduction capability between 4-9 pm to align with Energy Division guidance regarding RA availability hours. They do not currently reflect the full max event duration for many programs nor the ability to deliver reductions outside of the 4-9 pm windows.

Figure 53 shows examples of ex-ante output tables for SCE's SDP residential program and for PG&E's BIP program. In both cases, the tables show the utility specific 1-in-2 August monthly peak days for 2021. For SDP residential, the ex-ante impacts, 164 MW, were lower than the reductions delivered on the peak day the year prior, August 18, 2020, over a longer event duration. In general, DR resources deliver larger reductions on hotter days which coincide with the need for resources. Thus, the 1-in-10 reduction capability is higher than reduction capabilities under 1-in-2 peaking conditions. The ex-ante load impacts include spillover overs, which for SDP-R reflect snapback (load increases). The PG&E BIP example table shows the reductions relative to the firm service level and the continued reduction after the dispatch window. The spillover effects, whether positive or negative, are included since the changes in load fundamentally alter the loads that must be met to ensure resource adequacy. Both programs can deliver reductions for six hours but are only showing resources for RA for five hours.

Figure 53: Example of the Ex-ante Load Reduction Capability Hourly Outputs – SCE Summer Discount Plan Residential

Southern California Edison

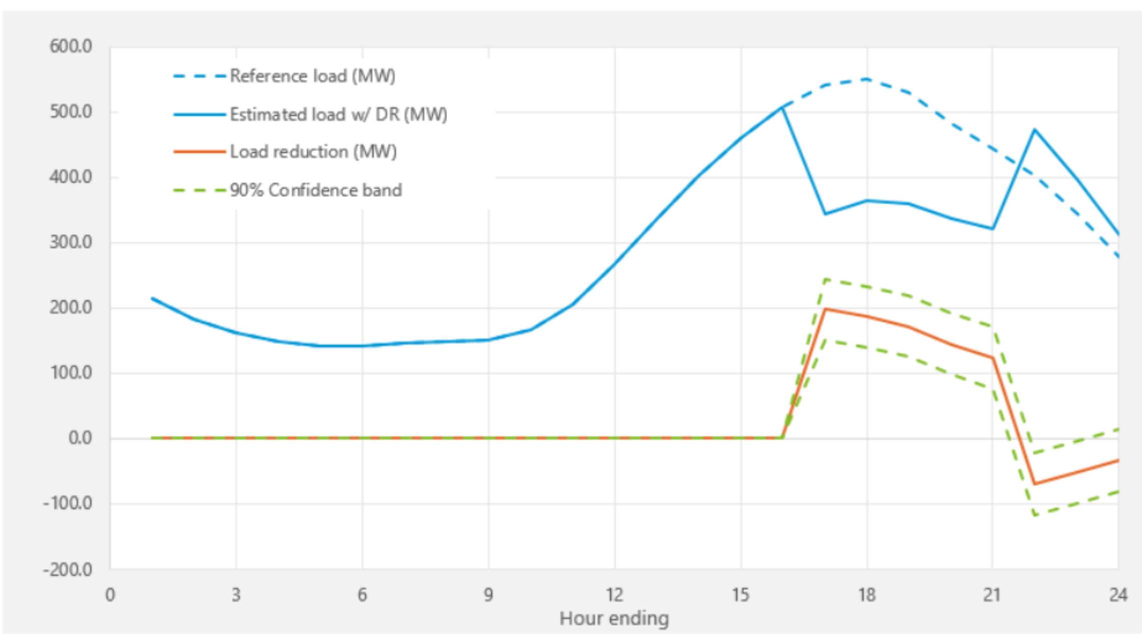
PY2020 Summer Discount Plan - Residential Ex Ante

Table 1: Menu options

Program	SDP-R
Type of result	Aggregate
Category	ALL
Subcategory	All
Weather Data	SCE Weather
Weather Year	1-in-2
Day Type	MONTHLY SYSTEM PEAK DAY
Month	8
Forecast Year	2021

Table 2: Event day information

Event start	4:00 PM
Event end	9:00 PM
Total sites	189,795
Total devices	221,618
Total AC tonnage	808,299
Event window temperature (F)	91.3
Event window load reduction (MW)	164.59
% Load reduction (Event window)	32.3%
COVID Index	0.50



Hour ending	Reference load (MW)	Estimated load w/ DR (MW)	Load reduction (MW)	% Load reduction	Avg temp (F, site weighted)	Uncertainty adjusted impact - Percentiles 5th	Uncertainty adjusted impact - Percentiles 95th	Std. error	T-statistic
1	214.83	214.83	0.00	0.0%	79.99	0.00	0.00	0.00	0.00
2	182.85	182.85	0.00	0.0%	78.61	0.00	0.00	0.00	0.00
3	162.82	162.82	0.00	0.0%	77.59	0.00	0.00	0.00	0.00
4	149.44	149.44	0.00	0.0%	76.55	0.00	0.00	0.00	0.00
5	141.84	141.84	0.00	0.0%	75.65	0.00	0.00	0.00	0.00
6	142.32	142.32	0.00	0.0%	75.00	0.00	0.00	0.00	0.00
7	147.23	147.23	0.00	0.0%	74.34	0.00	0.00	0.00	0.00
8	149.15	149.15	0.00	0.0%	74.24	0.00	0.00	0.00	0.00
9	150.34	150.34	0.00	0.0%	76.59	0.00	0.00	0.00	0.00
10	165.89	165.89	0.00	0.0%	81.03	0.00	0.00	0.00	0.00
11	205.48	205.48	0.00	0.0%	85.48	0.00	0.00	0.00	0.00
12	266.62	266.62	0.00	0.0%	89.14	0.00	0.00	0.00	0.00
13	336.42	336.42	0.00	0.0%	91.65	0.00	0.00	0.00	0.00
14	402.44	402.44	0.00	0.0%	93.85	0.00	0.00	0.00	0.00
15	458.75	458.75	0.00	0.0%	95.32	0.00	0.00	0.00	0.00
16	508.00	508.00	0.00	0.0%	95.43	0.00	0.00	0.00	0.00
17	540.33	342.98	197.35	36.5%	94.95	150.77	243.93	28.32	6.97
18	550.98	364.28	186.70	33.9%	93.33	140.23	233.18	28.25	6.61
19	530.22	358.94	171.27	32.3%	91.58	124.85	217.69	28.22	6.07
20	481.86	337.71	144.15	29.9%	89.92	97.71	190.59	28.23	5.11
21	444.49	321.00	123.48	27.8%	86.62	74.86	172.11	29.56	4.18
22	402.07	472.11	-70.04	-17.4%	83.39	-117.36	-22.72	28.77	-2.43
23	343.04	394.70	-51.66	-15.1%	81.18	-98.94	-4.37	28.75	-1.80
24	278.36	311.50	-33.13	-11.9%	79.48	-80.49	14.23	28.79	-1.15
Daily	**Reference load (MWh)**	**Estimated load w/ DR (MWh)**	**Energy savings (MWh)**	**% Change**	**Avg. Daily Weighted temp (F)**	**Uncertainty adjusted impact - Percentiles 5th**	**Uncertainty adjusted impact - Percentiles 95th**	**Std. error**	**T-statistic**
Daily kWh	7355.77	6687.64	668.13	10.0%	84.20	535.00	801.26	80.94	8.25

Figure 54: Example of the Ex-ante Load Reduction Capability Hourly Outputs – PG&E Baseline Interruptible Program

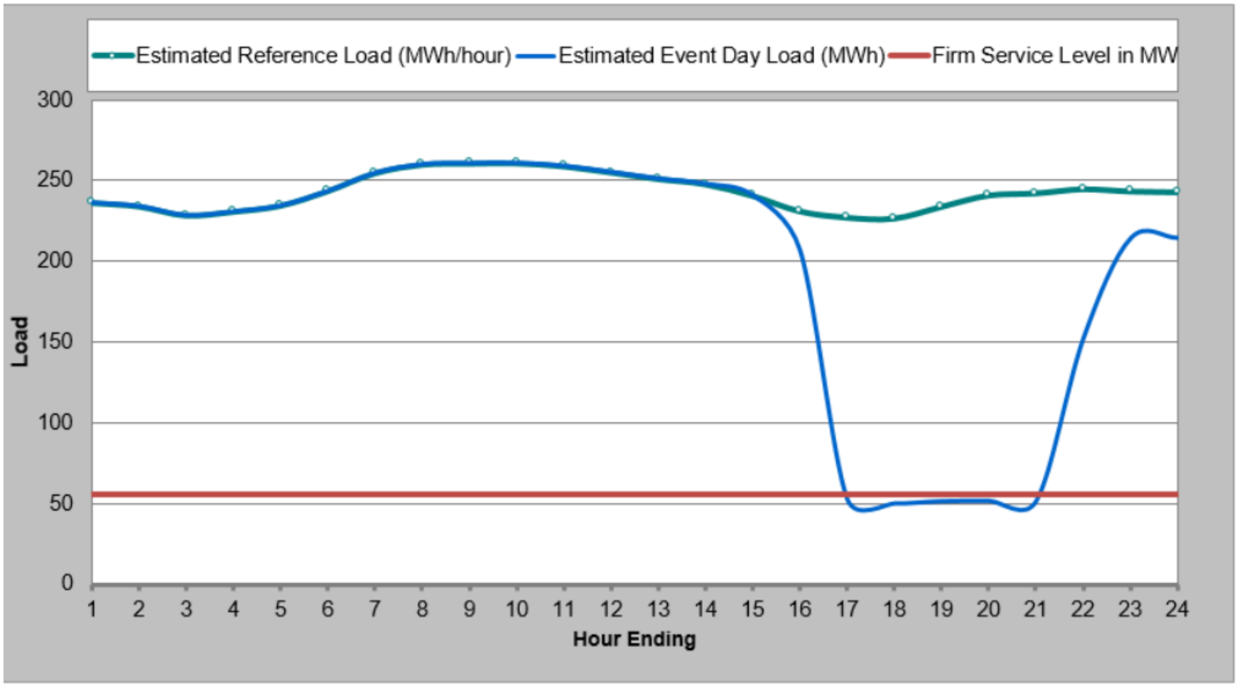
PG&E Base Interruptible Program (BIP) for PY2020: Ex-Ante Analysis

Menu Options:

Type of Results:	Aggregate Impact
Day Type:	Typical Event Day
Forecast Year:	2021
Weather Year:	Utility 1-in-2
Impact Level:	Portfolio-level impacts
Local Capacity Area:	All
Size Group:	All

Event Day Information:

Event Hours	Hours Ending 17 to 21
Heat Buildup (Avg. °F, 12 AM to 5 PM)	82
Number of Accounts Enrolled	308
Firm Service Level in MW	56
Event Hour Reference Load	234
Avg. Load Reduction for Event Window (MW)	183
% Load Reduction for Event Window	78%
Program FSL Achievement Rate	102%



Hour Ending	Estimated Reference Load (MWh/hour)	Estimated Event Day Load (MWh)	Estimated Load Impact (MWh/hour)	Weighted Average Temperature (°F)	Uncertainty Adjusted Impact (MWh/hr)- Percentiles				
					10th%ile	30th%ile	50th%ile	70th%ile	90th%ile
1	236	236	0	76	0	0	0	0	0
2	234	234	0	74	0	0	0	0	0
3	229	229	0	73	0	0	0	0	0
4	231	231	0	72	0	0	0	0	0
5	235	235	0	71	0	0	0	0	0
6	244	244	0	69	0	0	0	0	0
7	255	255	0	69	0	0	0	0	0
8	260	260	0	72	0	0	0	0	0
9	261	261	0	77	0	0	0	0	0
10	261	261	0	82	0	0	0	0	0
11	259	259	0	86	0	0	0	0	0
12	255	255	0	90	0	0	0	0	0
13	251	251	0	93	0	0	0	0	0
14	248	248	0	95	0	0	0	0	0
15	241	241	0	97	0	0	0	0	0
16	231	207	25	98	11	19	25	30	38
17	227	53	175	98	170	173	175	177	179
18	227	50	177	97	174	175	177	178	179
19	234	52	182	95	180	181	182	183	185
20	241	52	189	91	186	188	189	190	192
21	242	52	191	86	187	189	191	192	194
22	245	152	93	83	91	92	93	93	94
23	244	214	29	80	27	28	29	30	31
24	243	215	29	78	26	28	29	30	31

	Reference Energy Use (MWh)	Estimated Event Day Energy Use (MWh)	Change in Energy Use (MWh)	Cooling Degree Hours (Base 75° F)	Uncertainty Adjusted Impact (MWh/hour) - Percentiles				
					10th	30th	50th	70th	90th
Daily	5,836	4,747	1,088	226	n/a	n/a	n/a	n/a	n/a
RA Window	234	52	183	92	179	181	183	184	186

The current outputs produce reduction capability by hour and month and generally align with the 24-hour slice-of-day framework. However, they are not summarized concisely, and Energy Division staff would have to filter through the tables, identify the right set of tables, and combine them to view all 24 hours by month under conditions that align with the slice of day metrics.

However, 24-hour slice-of-day impacts by month can be easily summarized for staff given the existing outputs, which are also provided as a dataset. As an example, DSA produced Figure 52P, which uses historical, publicly available ex-ante table outputs to summarize load impacts in a manner consistent with the 24-hour slice-of-day framework.

Table 15: Example of Summarizing Load Reduction Capability Consistent with 24-hour Slice-of-Day Framework Using Current Outputs

Summer Discount Plan Residential 1-in-2 Monthly Peaks

Hour ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	0.0	0.0	5.5	60.0	66.5	129.8	186.0	197.3	198.8	92.2	52.6	0.1
18	0.0	0.0	3.0	52.3	58.5	121.2	176.8	186.7	189.6	83.8	44.5	0.0
19	0.0	0.0	0.4	40.8	45.2	106.3	161.0	171.3	174.6	70.7	32.8	0.0
20	0.0	0.0	0.0	22.2	23.1	80.0	132.6	144.2	145.6	47.8	16.1	0.0
21	0.0	0.0	0.0	11.6	12.1	63.6	112.0	123.5	124.2	35.2	8.2	0.0
22	0.0	0.0	-3.0	-38.0	-38.6	-42.9	-68.8	-70.0	-78.3	-57.3	-28.6	0.0
23	0.0	0.0	-0.4	-21.6	-21.7	-27.3	-49.3	-51.7	-59.8	-39.5	-16.9	0.0
24	0.0	0.0	0.0	-6.5	-7.3	-12.6	-30.8	-33.1	-39.6	-23.3	-5.6	0.0

Modifications Needed to Align with the 24-hour Slice-of-Day Resource Adequacy Framework

The current method requires producing hourly results for each event in a standardized format, including information about the number of participants called, event start and end times, weather conditions and confidence intervals. It also requires DR providers to produce estimates of DR capability by month and hour for 1-in-2 and 1-in-10 planning conditions that are grounded in actual event performance when possible. The core elements of the existing framework align well with the slice-of-day resource adequacy framework, which also requires estimates of resource capability by month and hour-of-day.

Our position is that hourly impacts that vary by month and hour and include spillover effects should be used for resource adequacy planning and are consistent with 24-hour SOD Framework. However, five (5) modifications needed to align more so with a slice-of-day resource adequacy framework for the 2024 test year:

1. Align weather conditions with the worst day of the month planning conditions as defined by the RA working group. Currently, load forecasting uses 1-in-2 weather conditions, which are used for DR. However, the definition of worst-day conditions for Resource Adequacy can change and DR needs to align with those conditions.

2. Allow DR providers some flexibility to reflect the full resource capability. To qualify for RA, currently DR resources currently must be able to deliver a minimum of 4 consecutive hours of reduction within the 4-9 pm hours for May-September.[56] A resource capable of delivering reductions for 6 hours should be able to show 6 hours but must show at least four consecutive hours of load reduction in the Availability Assessment Hours (AAH) window.

[56] CPUC D.22-06-050 at 125, ordering paragraph 6.

3. Once a DR provider has elected the hours to show reductions as part of qualifying capacity process (when the ex-ante load impacts are files), it cannot modify the dispatch hours since it fundamentally alters the 24-hour slice-of-day stack. In other words, LSEs would not be able to modify the dispatch hours in their 24-hour slice-of-day stack after the qualified capacity has been approved by the CPUC. This allows the CPUC to ensure the 24-hour slice-of-day stacks procured by the LSEs are consistent with the approved qualified capacity. Simply put, the sum of the parts should add to the whole (or not exceed the whole).

4. Codify that DR slice of day load impacts need to factor in:
   a. Weather scenario used for load forecasting
   b. Resource shape
   c. Maximum event duration
   d. Spillover effects, including pre-cooling, snapback, and/or persistence of impacts beyond dispatch
   e. Resource decay based on event duration

5. Require the production of a 24-hour slice-of-day summary table by month and hour, so Energy Division staff doesn't have to search for the information. DSA introduced a template for the 24-hour slice-of-day summary table.

For the 2024 test year, DSA and CLECA recommend the 24-hour slice-of-day framework maintain the current minimum requirements for max event duration, annual dispatch hours, monthly dispatch hours, and consecutive day availability outlined in the DR maximum cumulative capacity bucket.[57]

With the above changes and clarifications to the LIP, DSA and CLECA assert DSA's proposal will produce accurate hourly shapes for DR that can be used for the 24-hourly resource stack. The use of a static value across time will fail to accurately reflect DR capabilities on an hourly basis and would result in unnecessary procurement in some hours or misleading conclusion of resource sufficiency in other hours.

The DSA long-term proposal for alignment of the 24-hour slice-of-day also calls for producing a time-temperature matrix for variable and weather sensitive resources, and for developing a performance alignment metric (PAM) and bid alignment metric (BAM). A time-temperature matrix quantifies the relationship between demand reductions, temperature conditions, the hour of the day, event start times, and hours into an event. It is based on the same model used to produce ex-ante impacts under planning conditions and can be used to compare the ex-ante load impact reduction capability to the delivered reductions under actual conditions experienced. We recommend adding this element so the DSA long-term proposal can be made optional for the 2024 test year. CLECA supports the concept of these two performance metrics but does not support their adoption until historical results are produced and vetted.

e. CLECA on Adders

Authors: CLECA

[57] CPUC D.22-06-050 at 125, ordering paragraph 6.

Transmission and Distribution (T&D) Adders

CLECA supports the retention of the Transmission Loss Factor (TLF) and Distribution Loss Factor (DLF). Additional capacity must be available to deliver electricity to end use customers, to overcome T&D losses that are incurred when moving the power through the grid. Reducing 1 MW of load results in a greater than 1 MW reduction in need at the resource, because the T&D losses are not incurred. The CPUC acknowledged this in D.21-06-029, Ordering Paragraph 13, which states the following:

> 13. The transmission loss factor (TLF) and distribution loss factor (DLF) components of the planning reserve margin adder for demand response (DR) resources shall be retained. The DLF adder shall be incorporated into qualifying capacity (QC) values for DR beginning in the 2022 Resource Adequacy (RA) compliance year. For the TLF adder, Energy Division Staff shall continue the current practice of grossing up RA filings and sending credits to the California Independent System Operator to account for transmission losses.

CLECA support retaining the current practice for both the TLF and DLF.

Planning Reserve Margin Adder

CLECA supports retention of the entire PRM adder, on the grounds that capacity requirements are determined as peak load plus the PRM. Reducing load thus eliminates the incremental PRM associated with that load. For planning, DR is treated as a load modifier because it is non-firm load. Not treating supply-side DR in the same way for planning purposes results in treating load-modifying and supply-side DR differently, although they both effectively create an additional effective capacity margin by reducing load.

CLECA does not support eliminating the 6% of operating reserves from the PRM. If load is reduced, the need for its associated operating reserves is similarly reduced. The CAISO should be able to distinguish non-firm load as DR for planning purposes. In operations, the operators should be informed of how much load is non-firm and can be shed if needed.

Should the DR load no longer be grossed up for the full PRM (load forecast variation and forced outage rate), then the counting approach for DR needs significant modification to prevent discriminatory treatment of supply-side DR despite its being a preferred resource. Currently, the LIP use the expected load reduction during a 1-in- 2 weather event. However, the likelihood of DR being called during such conditions is very unlikely. Since the reliability standard is 1 day in ten years, the expected DR during a 1-in-10-year weather event should be utilized rather than the 1-in-2 forecast for setting DR QC. Some DR programs, such as air-conditioning cycling, are highly weather sensitive and counting them based upon 1-in-2 weather conditions would significantly undercount their contribution to reliability. By understating DR's capability during a reliability event, the lost value would be met by less preferred resources to meet the RA targets.

Currently, thermal resources have no reduction in QC due to forced outage rates.58 DR's QC is based upon historical performance, which include non-performance (which is like a forced outage). This leads

[58] There is a proposal to derate thermal resources using turbines for air temperature and there is another proposal to derate the QC for forced outage rate, but neither have been adopted by the CPUC.

to inequitable treatment of DR as well. Therefore, a DR QC value should be based upon all customers responding to a DR event which would be more comparable to other supply-side resources.

V. Comparison of the proposals

All the proposals were based on continued use of the results of the LIP. The DSA DR QC proposal is very similar to CLECA's proposal and CLECA has decided to support it. The main differences between the DSA/CLECA's proposal and Energy Division's Options 1 and 2 vs. Energy division's Options 3 and 4 are whether spillover effects are included for pre- and post-event hours.

VI. Consensus and non-consensus items

All the proposals were based on continued use of the results of the LIP. They differed in their treatment of the use of the 24-hourly data from the LIP for DR QC for each hour of the SOD framework. DSA and CLECA proposed to use the data for each hour. DSA/CLECA proposed an option to use a time-temperature matrix to vary QC for weather-sensitive DR programs. Energy Division proposed 4 options, including using the lowest QC value for the DR program during an event when it was called. While simpler, this 4th Option would not capture the temperature-sensitivity of DR.

There were different opinions on the use of the PRM adjustment. CLECA supported it but the IOUs did not. If the PRM adder is not used, CLECA proposed that the QC be based on a 1-in-10 weather year. Any change in the composition of the adders applied to load forecasts must also be applied to the supply side. There was consensus support for the continued use of the TLF and DLF.

VII. Questions for parties

- What degree of flexibility is possible in RA showings for DR?
- Can 6-hour DR resources be shown for 6 hours, consistent with their availability, as long as the hours include the Availability Assessment Hours?
- DSA, CLECA and the IOUs support the ability to show all the hours that a DR resource may perform, up to the daily maximum per service account. DR resources with impactful spillover effects would have a 24-hour profile with a pre-determined call window. Length of the call window would be limited to the cumulative event hours per day per service account and encompass four consecutive hours of the Availability Assessment Hour (AAH) window from 4-9 pm. DR resources without impactful spillover effects would be shown, based on factors such as the LSE's own load shape, RA minimum requirements to maximize the resource's contribution to system reliability needs, program rules, and tariff schedules.

VIII. References

- Energy Division 9/16 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-16-2022-demand-response/dr-workshop_ed.pdf
- Demand Side Analytics 9/16 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-16-2022-demand-response/demandsideanalytics_ra_dr_working_group_2022-09-16.pdf

- IOU 9/16 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-16-2022-demand-response/dr-workshop_ious.pdf
- CLECA 9/16 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-16-2022-demand-response/2022-09-cleca-dr-counting-proposal-under-slice-of-day-cpuc-workshop-final.pdf
- SCE 9/29 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-29-2022-test-year-follow-up-on-remaining-issues/workshop-9_sce_220929.pdf

vii. Resource Counting for Hydro

Authors: PG&E, CAISO

IX. Background

Authors: PG&E

In phase 1 of RA Reform, there were two proposals on how to treat hydro resources. SCE proposed a single monthly value, while PG&E proposed a monthly profile. Both methodologies would use existing hydro counting rules, although PG&E's would have involved revisions to the existing methodology to capture hourly data. In Decision D.22-06-050, the Commission adopted SCE's proposal to use a single monthly value, noting that PG&E's proposal for "hourly shapes at a resource level may be too complex for initial implementation."[59] While hydro was not scoped into the three workstreams outlined by the Commission in D.22-06-050, a chapter has been added to the workshop report to capture a presentation CAISO made on hydro counting.

X. Issues

Authors: PG&E

Whether a single monthly value or hourly profile should be used for hydro resource counting.

XI. Presenters and Dates

Authors: PG&E

- Workshop 5: August 23, 2022:
    - CAISO

XII. Proposal Summaries

f. CAISO

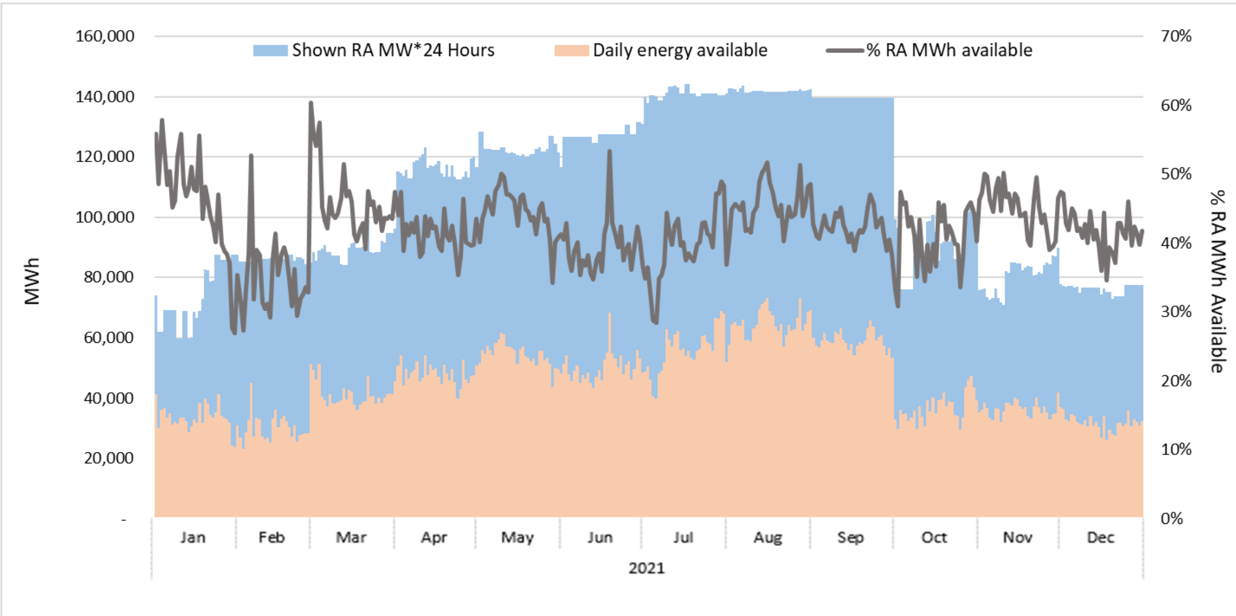
Authors: CAISO

At the 8/23 workshop, the CAISO presented on hydro counting under the CPUC's 24-hour resource adequacy framework. The CAISO stated that accurate counting of energy-limited resources' energy output is critical under the CPUC's 24-hour resource adequacy framework to ensure sufficient energy to meet demand and charge batteries. At the 9/21 workshop, the CAISO provided analysis showing that

[59] D.22-06-050, p. 89.

scheduling coordinators for hydro resource adequacy resources limit hydro resource availability far below 24-hour resource adequacy values on a daily basis (at a static monthly QC level) by shaping energy bids across the day (offering less in off-peak hours) or by submitting daily energy limits to the CAISO that limit the total energy a resource can be scheduled for in the day-ahead market. The CAISO recognizes these daily limits may be derivative of longer-term use limitations.

Figure 55: 2021 Hydro RA – Daily available energy v. 24-hour RA values



The CAISO recommended that the CPUC consider hourly shaped QC values for hydro resources as static QC values for hydro resources may overestimate total monthly energy available from these resources.

XIII. References

- CAISO 8/23 Presentation: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-history

viii. Planning Reserve Margin (PRM)

Authors: NRDC, with support from SCE, MRP, CAISO, collaboration with ED

I. Background

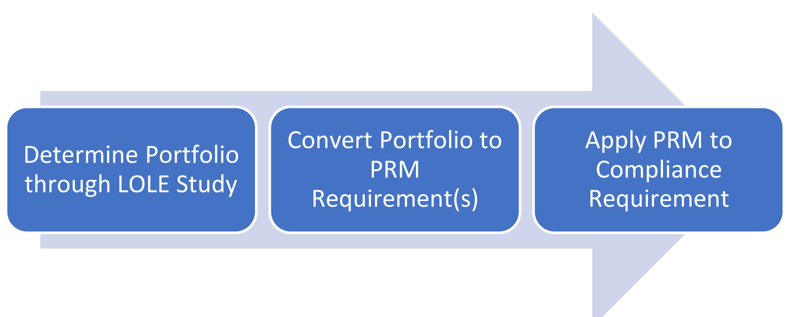
Authors: NRDC, ED, SCE, MRP

The Planning Reserve Margin (PRM) is a critical component of the RA program. The PRM is used as a factor to adjust load such that the RA obligation is sufficient to meet a specific reliability standard based on the adopted counting rules and peak load forecast. Historically, the PRM has been a single value (15%) applied to the peak load forecast for each month and has approximately represented the additional resources above the forecast peak to address operating reserves, load forecast "error,"[60] and generator outages.

Successful and "correct" calibration of the PRM is a critical step in meeting the balanced policy goals of the RA program, including ensuring system reliability to a desired standard at minimum ratepayer costs[61]. Calibration of the PRM against the adopted load and resource counting rules is the final step to ensure LSEs procure sufficient resources to meet reliability needs. A PRM which is too low risks an insufficient showing from LSEs to meet reliability needs and may leave some resources providing critical reliability services uncompensated, leaning on CAISO backstop procurement actions, and risking the unplanned exit of those resources from the market. A PRM which is too high risks excessive procurement costs for LSEs, risks unnecessary non-compliance events for LSEs, and may drive scarcity pricing in the RA market. While it is important to recognize inherent limitations in the precision of stochastic reliability modeling, particularly in the modern era of shifting climate and a transition to a more complex resource fleet, adopting a PRM which is accurate to the desired reliability standard remains a critical step in the RA process.

As the grid evolves to rely on a more complex and diverse portfolio of supply, the RA program and the corresponding PRM must evolve as well. In D.22-06-050[62], the Commission outlined a general framework for determining and applying the PRM under the Hourly Slice of Day framework, including the following core steps.

Figure 56: General Framework for Applying the PRM in Slice of Day



- **LOLE Study:** Development of a reliable, indicative portfolio representative of existing and planned resources and calibrated to a specific reliability metric through a refreshed Loss of Load Expectation (LOLE) study;
- **Conversion:** Conversion of the indicative portfolio to a PRM value calibrated using a heuristic tool that translates the LOLE study to the counting rules adopted for Slice of Day;

[60] The RA program utilizes a 1-in-2 load forecast for compliance purposes, but is calibrated to ensure sufficient resources for more severe, less frequent load conditions.
[61] California Public Utilities Code Section 380 (b)
[62] D.22-06-050 Appendix A, p. 2, *Planning Reserve Margin.* https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540634.PDF

- **Single Annual PRM:** Application of a single PRM value, determined through the above steps, to all hours of the year.

The adopted process provided a general framework for determining and applying the PRM which has been further analyzed and developed by parties through Workstream 2. Workstream 2 included proposals and presentations from SCE[63], NRDC, MRP, CAISO[64], and ED[65] to refine the adopted framework. Proposals and presentations, discussed below, provide a range of views on implementation of the above framework; however, in broad strokes, parties seem largely aligned on the core framework for determining and applying the PRM under the 24-hourly SOD construct. Key considerations for Workstream 2 – PRM have included:

- **LOLE Study:** How should Energy Division's refreshed LOLE study be performed? Should the LOLE study be performed to determine an annual portfolio or monthly portfolios?
- **Conversion:** What tools and assumptions should be used to convert the LOLE study to a PRM that may be applied in Slice of Day?
- **Single Annual PRM:** What is the single annual PRM required to maintain 0.1 LOLE based on Energy Division's refreshed LOLE study? Is it feasible to utilize a single annual PRM for all months? If so, what PRM should be selected? If not, how would monthly PRMs be determined?
- **Infeasibility:** How should the RA program resolve potential compliance infeasibility arising from the identification of reliability needs beyond the existing or planned portfolio of resources?
- **Process and Timing:** When, how frequently, and in which proceeding should the LOLE study be conducted?

These questions and issues are discussed further in the Issues and Proposals sections.

II. Issues

Authors: NRDC, ED, SCE, MRP

As discussed above, four key themes emerged around the PRM calibration discussion: the LOLE study, the conversion tool, the use of an annual or monthly PRM, and discretion to adjust the portfolio. While the LOLE study garnered significant workshop attention, the specific methodology and inputs of the LOLE study are not in scope for this Workstream. The tools developed by NRDC and SCE to perform the PRM conversion in alignment with resource counting rules have not been controversial with parties. This leaves two issues – the application of the PRM as a single annual value or with monthly granularity, and a specific process for discretion to adjust the portfolio relative to the results of the LOLE study.

LOLE Study

[63] SCE 2030 analysis.
[64] CAISO analysis.
[65] Astrape analysis.

The workshop series, parties expressed significant interest in the mechanics and input assumptions being utilized by Energy Division for the refreshed LOLE study[66] [67]. Energy Division presented preliminary results of PRM calibration using a refreshed, annual 2024 LOLE study presented by the IRP Modeling Advisory Group[68] [69]. As the scope of the workstream was limited to the process of translating the LOLE study to a PRM, and not the LOLE study itself, a deeper review of the LOLE study methodology and inputs was deferred to the next phase of the RA proceeding. Parties expect the Energy Division to submit its final study in January 2023 and hope to receive routine updates from the Energy Division as it performs its study. Parties should have additional opportunities to provide feedback to Energy Division and work collaboratively with Staff.

Conversion

Conversion of the portfolio using a heuristic tool followed a relatively linear path from the direction in D.22-06-050, with one significant caveat: without monthly portfolios produced by a monthly LOLE study, parties needed to determine a process to translate an annual portfolio to PRMs which would be applied to monthly peak forecasts.

Prior to D.22-06-050, NRDC provided a proof-of-concept tool to convert the 2022 LOLE study portfolio into monthly PRM values aligned with the monthly portfolios identified in the LOLE study[70]. NRDC's tool could be calibrated using several resource profile options and was accompanied by another spreadsheet tool intended to provide quantitative comparisons of different solar and wind resource counting methodologies. NRDC's tool applied basic resource counting logic to thermal, hydro, nuclear, and import resources and shaped profiles for solar, wind, and demand response. Storage resources were dispatched to any hour in which non-storage resources were insufficient to meet the compliance obligation. The tool uses the 1-in-2 hourly load profile as a base, with a PRM multiplier which augments every hour's compliance requirement.

To determine the PRM for each month, the tool used the Excel Solver to determine the maximum PRM value which could be sustained while meeting the following constraints:

- Instantaneous storage output (MW) must not exceed total storage power capacity (MW)
- Cumulative daily storage output (MWh) must not exceed total storage energy capacity (MWh)
- The resource mix must be sufficient to meet the compliance requirement (MW) in all hours

[66] SCE, 8/17/22, p.5-10, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2022-planning-reserve-margin/workshop-4_sce_220817.pdf
[67] MRP, 9/14/22, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-14-2022-planning-reserve-margin-part-2/workshop-7_mrp_220914.pdf
[68] .July 19, 2022 - Procurement Framework & Options for PSP Action (ca.gov)
[69] Energy Division presentation, 8/14/22, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-14-2022-planning-reserve-margin-part-2/energy-divsion-2022-09142022_edlolestudysod.pdf
[70] NRDC PRM Calibration Tool, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/ra-reform-excel-workbooks/2022_04_29_slice-of-day-nrdc.xlsx

- The resource mix must be sufficient to provide sufficient excess capacity (MWh) to charge all dispatched storage, including round-trip losses

NRDC's tool provided the basic data and logic necessary to assess the portfolio in aggregate on a monthly basis, consistent with the general thinking prior to the issuance of D.22-06-050. NRDC's tool has been used by Energy Division for preliminary portfolio analysis, as discussed in the Proposals section, and has been reasonably well vetted by stakeholders. NRDC's tool was designed to identify monthly PRMs, consistent with the 2022 Monthly LOLE study, and can be used easily for comparison across multiple months. However, due to the fundamental design choice of designing the tool around aggregate portfolio constraints, NRDC's tool is not designed to incorporate resource-specific constraints, such as thermal run-time limits, and does not assess energy sufficiency for storage resources with charging limitations, such as the Investment Tax Credit. To the extent these constraints are incorporated into the Slice of Day framework, NRDC's tool would need revisions to align the PRM calibration process with the adopted counting rules.

Following D.22-06-050, SCE developed a PRM calibration tool[71] similar to the NRDC tool referenced in D.22-06-050 but designed to incorporate the specific limitations of individual resources. In contrast to the NRDC tool, the SCE tool is capable of being calibrated to reflect the operating limitations of individual resources. SCE's tool, which is built as a function within its Slice of Day compliance showing tool, uses a similar general optimization framework to NRDC, intending to find the maximum PRM value for which the LOLE-identified portfolio is in compliance; however, SCE's tool uses logic to iteratively apply resource production across short hours until the portfolio is in compliance, enabling it to optimize multiple sets of resources (NRDC's tool simply optimizes the battery fleet as a whole). SCE's tool is capable of determining the PRM requirement for any month using a drop-down tab but is designed to be used for a single month.

Parties did not express clear concerns or preferences with regard to the tool development for calibration proposed by SCE or NRDC. While SCE's tool is more capable of meeting the anticipated specificity of the resource counting structures, calibration work from Energy Division, to date, has used the NRDC tool. In implementing the SOD PRM, Energy Division should utilize a tool which precisely reflects the logic and requirements adopted for compliance to ensure alignment in the determined PRM and the compliance showings from LSEs.

Annual vs Single Monthly PRM

Historically, the Commission has adopted a single annual PRM for all months of the year. This PRM was chosen without regard to whether the aggregation of reliability risk across all months results in the desired 0.1 LOLE standard. Parties have differed on the importance of enhancing RA program calibration through a monthly PRM in Slice of Day, with some parties arguing that an annual PRM, in line with D.22-06-050, is viable to meet reliability goals, and other parties arguing that an annual PRM blunts

[71] SCE PRM Calibration Tool, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/ra-reform-excel-workbooks/sce-slice-of-day-24-slice-model-20220921.xlsx

much of the intended precision and calibration intended in SOD program design, potentially resulting in increased LOLE risk.

Following the direction in D.22-06-050 to use a single annual PRM, SCE[72] proposed calibrating the annual PRM to the highest load hour using a heuristic tool similar to that initially proposed by NRDC, as it would reflect the largest portfolio need across the year. However, further analysis from Energy Division[73] illustrated that an annual PRM set based on September need (or a PRM based on July or August) could result in over- or under-procurement in other critical months, a reality exacerbated by the significant peak differential across summer months in the 1-in-2 load forecast. In the final workshop, NRDC proposed an amendment to the SCE model which would set monthly PRMs calibrated to the annual portfolio for any at-risk month, defined as months with modeled LOLE in the LOLE study, and the use of an annual PRM for non-at-risk months.

It is less clear what PRM is reasonable to apply for non-critical months without an expectation of reliability risks from the annual portfolio. Philosophically, parties agree that resources providing reliability services during non-peak months should receive compensation through RA contracts; however, parties have not identified a clear or consensus method to assess reliability risk and calibrated portfolio need in non-summer months. Parties generally agree that the method used previously to determine LOLE on a monthly basis, used historically for monthly ELCC studies, does not produce useful results for RA program calibration. Without a clear path to assess off-peak reliability needs, parties have yet to align on a consensus proposal to apply the annual portfolio to PRM requirements throughout the year.

Infeasibility

In wrap-up workshops, some parties expressed concern about the potential for a mismatch between the portfolio of resources identified as necessary for reliability in the PRM study and the resources available to LSEs to be shown for compliance. Specifically, parties raised a concern that the LOLE study may require resources which do not exist and are not feasible to develop in a timely fashion, leading to inherent non-compliance with the RA requirement. Parties noted that this issue relates more broadly to resource planning in the IRP. Similar proposals from NRDC and East Bay Community Energy (EBCE) are included below related to this concern.

Process and Timing

[72] SCE Presentation, Test Year Wrap Up, Slide 6
https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-29-2022-test-year-follow-up-on-remaining-issues/workshop-9_sce_220929.pdf

[73] Energy Division Presentation, October 6, 2022 Presentation, Slide 10
https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_energy-division_221006.pdf

From a process perspective, parties made various proposals regarding the timing and frequency of LOLE studies and PRM analysis. The timing and frequency of the LOLE study process should balance the need for frequency driven by the rapid pace of change of the system against the workload impacts to Energy Division and the disruptive effects of updates on market participants, which may be mitigated through improved long-term forecasting of system needs and parameters. In its initial conceptual presentation, NRDC proposed[74] annual or semi-annual recalibration to be performed as part of the IRP proceeding, including multi-year forward forecasts based on anticipated resource development and retirements. MRP proposed[75] revisiting the PRM every two to four years. SCE proposed[76] a two-year refresh aligned with the IRP cycle.

III. Presenters and Dates

Authors: NRDC, ED, SCE, MRP

- **December 2021 Need Determination and Allocation Workshop (RA Reform Phase 1)**
  - **NRDC – PRM Conceptual Framework**[77] – NRDC presented a conceptual framework for the translation of the results of the monthly LOLE study to a PRM calibrated to Slice of Day, including recommendations for frequency and horizon of LOLE and PRM updates and forecasts. The conceptual framework is described further in proposals below.

- **Workshop 4: August 17, 2022: Planning Reserve Margin Workshop 1**
  - **SCE – Overview of PRM**[78] - SCE made a presentation on LOLE modeling, the application of the PRM to Slice of Day using an annual LOLE study, and a proposal to calibrate a capacity expansion model using Slice of Day instead of the current ELCC-based constraint.
  - **NRDC – PRM Calibration Refresher**[79] – NRDC presented a refresher on the PRM calibration process presented in 2021 and discussed tradeoffs between the use of an annual PRM, as indicated in D.22-06-050, and the monthly PRM results implied by the monthly LOLE study.

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[74] NRDC, 12/1/2021, Slide 11. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-6-nrdc_2021_12_01_np-energy_nrdc_need-determination-and-allocation.pdf

[75] MRP, 10/6/22, Slide 3, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_mrp_221006.pdf

[76] SCE, 8/17/22, Slide 3. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2022-planning-reserve-margin/workshop-4_sce_220817.pdf

[77] NRDC, 12/1/21. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-6-nrdc_2021_12_01_np-energy_nrdc_need-determination-and-allocation.pdf

[78] SCE, 8/17/22, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2022-planning-reserve-margin/workshop-4_sce_220817.pdf

[79] NRDC, 8/17/21 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2022-planning-reserve-margin/workshop-4_nrdc_220817.pdf

- **ED – LOLE Studies and Translation**[80] – ED, with its consultant, Astrape, made a presentation on types of PRM across counting regimes and its proposed construct for implementing the PRM under Slice of Day.

- **MRP – PRM Principles**[81] - MRP presented considerations and principles for PRM calibration, including the importance of achievement of a 0.1 LOLE and recognition that the PRM is a function of resource mix and load forecast.

- **Workshop 7: September 14, 2022: Planning Reserve Margin Workshop 2**

  - **SCE – Overview of PRM**[82] - SCE presented its proposal to translate the results of the LOLE study using its Excel-based tool.

  - **ED – LOLE and PRM Structure and Results**[83] **-** ED presented preliminary results of calibration of its revised LOLE study using the NRDC PRM Calibration Tool, and highlighted calibration considerations related to monthly specificity and load inputs.

  - **MRP – PRM Calibration Methodology**[84] - MRP made a presentation on the LOLE study to be used for PRM calibration and presented a proposal to determine and test monthly PRMs by removing capacity until annual PRM and 0.1 LOLE reliability are achieved.

- **Workshop 9 and 10: September 29 and October 6, 2022 Wrap-Up Workshops**

  - **SCE – Final PRM Calibration Proposal**[85] – SCE presented its final proposal on PRM calibration, including the 4-point calibration process described in the *Proposals* section.

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[80] ED, 8/17/22, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2022-planning-reserve-margin/workshop-4_ed_220817.pdf
[81] MRP, 8/17/22, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2022-planning-reserve-margin/workshop-4_mrp_220817.pdf
[82] SCE, 9/14/22. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-14-2022-planning-reserve-margin-part-2/workshop-7_sce_220914.pdf
[83] ED, 9/14/22. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-14-2022-planning-reserve-margin-part-2/energy-divsion-2022-09142022_edlolestudysod.pdf
[84] MRP, 9/14/22. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-14-2022-planning-reserve-margin-part-2/workshop-7_mrp_220914.pdf
[85] SCE, 9/29/22. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-29-2022-test-year-follow-up-on-remaining-issues/workshop-9_sce_220929.pdf

- **NRDC – Monthly PRM Adjustments and Policy Adjustment**[86] - NRDC presented a proposal to calibrate the PRM on a monthly basis for summer months and to provide discretion to adjust the portfolio and commensurate PRM based on resource availability or other policy considerations, if necessary, as described in the *Proposals* section.

- **CAISO – Exceedance and PRM Discussion**[87] - CAISO presented its analysis on resource performance and considerations for the PRM, including concerns about the use of a single PRM for all months of the year.

- **ED – LOLE and PRM Structure and Results**[88] - ED presented its updated PRM analysis results, including three stress tests to assess different methods of applying annual or monthly PRMs to achieve a 0.1 LOLE portfolio.

- **MRP – PRM Calibration**[89] **-** MRP presented updated PRM calibration principles and considerations, emphasizing the importance of ensuring 0.1 LOLE in all months and recommending that the LOLE study and PRM recalibration take place every 2-4 years.

- **EBCE – Feasibility Adjustments**[90] - EBCE presented a proposal for the Commission to assess and adjust the PRM requirement should the portfolio be infeasible given the State's available resources.

IV. Proposal Summaries

a. NRDC Conceptual Framework, December 2021

Authors: NRDC

The initial conceptual framework for calibrating the PRM was presented by NRDC at the December 1, 2021, Need Determination and Allocation workshop[91], identifying a basic structure which would require a PRM set at the maximum level with a feasible compliance solution based on the load forecast,

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[86] NRDC, 10/6/22, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_nrdc_221006.pdf

[87] CAISO, 10/6/22, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_caiso_221006.pdf

[88] ED, 10/6/22, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_energy-division_221006.pdf

[89] MRP, 10/6/22, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_mrp_221006.pdf

[90] EBCE, October 6, 2022. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_ebce_221006.pdf

[91] NRDC, December 1, 2021. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/workshop-6-nrdc_2021_12_01_np-energy_nrdc_need-determination-and-allocation.pdf

indicative resource portfolio, and adopted counting rules. NRDC proposed to refresh the LOLE study every 1-2 years in light of the rapid system change occurring in the 2020s, with forecast analysis assessing future program calibration that should be integrated with the IRP proceeding. This general framework and accompanying "proof of concept" tool were directionally adopted in D.22-06-050 for further development in Workstream 2.

b. SCE Annual PRM Proposal, August and September 2022

Authors: SCE

Subsequent to D.22-06-050, SCE continued the development of the PRM calibration process, presenting policy proposals and tools throughout the workshop series. In its final PRM calibration presentation[92], SCE proposed a PRM calibration based on the following steps:

1. *Determine volume and mix of resources that achieve reliability and other targets (Iterative LOLE process)*
2. *Convert nameplates and characteristics to SOD counting (hourly ELCC, daily limitations, etc.)*
3. *Create system-level 24-hourly-slice RA stack consistent with steps 1 and 2 that maximizes PRM achieved for the highest load day while satisfying SOD requirements*
4. *Resulting PRM becomes the RA PRM*

As part of its proposal, SCE demonstrated the utilization of its tool to determine the PRM using individual resource characteristics, including thermal limitations, representation of hybrid limitations, and unique storage resource attributes.

c. Energy Division Study Results, August, September, October 2022

Authors: ED

Energy Division, with its consultant Astrapé, made three presentations on PRM calibration throughout the workshop series. In its final presentation, Energy Division presented preliminary PRM calibration results using placeholder resource counting rules and presented its final list of PRM calibration steps:

1. Construct SERVM portfolio that meets 0.1 LOLE (this may include using the neighbor import assumption to calibrate the 0.1 LOLE)
2. Define the SERVM resources in a SOD tool. This would convert the SERVM portfolio to SOD accounting methodologies
3. Input managed load – use CEC 1-in-2 IEPR -peak day of every month to align with SOD
4. Solve for the highest load multiplier that the reliability compliant portfolio can support for each month. The month with the lowest load multiplier will set the annual requirement. The load multiplier is interpreted as a planning reserve margin (PRM).

Additionally, Energy Division introduced a stress test concept to address concerns regarding an annual PRM (selected in step 4) if a 0.1 LOLE level were not achieved across all months:

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[92] SCE, September, 2022. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-29-2022-test-year-follow-up-on-remaining-issues/workshop-9_sce_220929.pdf

5. Test system reliability in SERVM by applying the PRM from step 4 to all months. The monthly PRM is achieved by adding load in months with organic (?) reserve margins > PRM.
    a. Imposing the lowest monthly PRM results in annual LOLE > 0.1.
    b. Raise the PRM produced in step 4 in all months uniformly until annual LOLE = 0.1

For purposes of understanding the translation steps proposed above, Astrapé updated the translation exercise and presented the results during the workshop. For the exercise, Astrapé used the NRDC tool using the following inputs and assumptions:

- 2024 SERVM portfolio used from recent LOLE study
- Imposed a 5% forced outage rate on capacity additions needed to tune to 0.1
- Conventional resources input at nameplate
- Storage resources' capacity input at nameplate
    - Energy constraint aggregated (Total energy = sum of individual storage resource energies capped at 8 hours of duration for projects with longer duration.)
- 70% Exceedance value for Wind/Solar profiles
- Used two different forecasts to show changes to monthly PRMs under both SERVM worst day per month (in 23 years of load simulation data) and CEC 2021 IEPR 1-in-2 monthly worst day forecast for this calibration example)

Astrapé presented a comparison of the 1-in-2 CEC IEPR load net of renewable production to the SERVM worst day net load profiles (slide 6) to highlight the monthly differences in load forecast variability between the two forecasts. This was done to highlight the larger gap between July and Sept in the CEC forecast compared to SERVM forecast. The graphic also highlighted that the SERVM forecast includes higher levels of load variability than the CEC's 1-in-2 and this results in a lower PRM.

Astrapé described the purpose of the stress tests as a way to analyze monthly reliability when applying single/annual PRM. All of the tests were done by adding flat blocks of load in the 2024 LOLE model. For Stress Test 1, Astrapé imposed the September PRM on all months of the year and found that aggregate LOLE across all months resulted in approximately 0.4 LOLE, a significant increase above the 0.1 LOLE threshold. For Stress Test 2, Astrapé imposed the September PRM on September, and then either the July or August PRM on all other months. This test found that by applying the higher July or August PRMs on the other months, while keeping September PRM unchanged, the result was a higher level of reliability, meeting the 0.1 LOLE standard across the full year. This test also suggests that you would need two PRMs. For Stress Test 3, Astrapé imposed the same PRM in all months starting with the September PRM and increased the PRM until the annual aggregate monthly LOLE was equal to 0.1. This test resulted in a PRM that was 2-3% higher than the September PRM. However, considering the baseline September PRM required the full portfolio of resources identified in the annual LOLE study, an additional 2-3% would require resources well beyond the annual portfolio.

d. NRDC Monthly PRM Calibration and Reasonableness Adjustment, October, 2022

Authors: NRDC

Building from Energy Division's results illustrating the challenge of applying a single annual PRM, NRDC proposed a modification to the PRM calibration process to adopt specific monthly PRMs for all months with reliability risk while applying a generic PRM for non-at-risk months. At-risk months would be defined as any month with modeled LOLE in the annual LOLE study, likely to include July, August, and September. These months would utilize a PRM set at a level necessary to show the full annual portfolio.

Other months, unlikely to experience LOLE and unlikely to require the full portfolio, would have a generic PRM applied, as determined through the annual PRM process established by SCE. As a stress test, Energy Division could re-run the annual LOLE study with monthly portfolios tuned to the on- and off-peak compliance requirements to determine whether the generic PRM values in off-peak months risks introducing LOLE either in aggregate (on an annual basis) or for those specific months. To the extent that LOLE is inadvertently introduced in an off-peak month, Energy Division could recalibrate the PRM for that month until LOLE events are eliminated.

One concern raised by NRDC was the potential for some resources identified in the annual portfolio to be unutilized in the modeling in specific months and, in the market, unavailable to LSEs. Specifically, hydroelectric resources with annual energy limitations or imports supported by regional hydroelectric resources may not have sufficient energy to offer RA into the market by late summer. To the extent the LOLE model is observing and modeling the same annual energy limitations, failure to show these resources in September may be consistent with the reliance (or non-reliance) of the LOLE model on these resources; however, LSEs may be obligated to procure these resources based on an annual portfolio. An improved understanding of both real-world hydroelectric risk and the hydroelectric representation in the LOLE model may illustrate or resolve this concern.

Finally, NRDC proposed that some discretion may be warranted to the extent that the LOLE study results in a portfolio that is infeasible or is in contravention to other policy considerations. For example, if a refreshed LOLE study in 2023 were to indicate a PRM requirement that is infeasible for LSE compliance in 2024, it is unclear that establishing an infeasible PRM would be an optimal policy outcome. The Commission may wish to adopt a feasible interim PRM while taking related steps to bring additional emergency and long-term resources online through other proceedings.

e. Middle River Power Monthly PRM Calibration, September and October 2022

Authors: MRP

Middle River Power proposed [93,94] that the PRM should be calibrated to ensure a 0.1 LOLE risk throughout the entire year. However, due to the monthly nature of the RA program and the Commission's order to adopt a single PRM for all months of the year, the portfolio that results from the LOLE study must be calibrated so that the portfolio of resources will meet the monthly demand forecast plus the PRM. This will provide the best assessment of reliability based on the shown RA fleet and not rely on any backstop procurement. ED's recent study update showed that if the PRM for all months was set only to the September PRM, the LOLE of the grid would be 0.4 LOLE, not 0.1 LOLE. That is in stark contrast to the 0.1 goal of the RA program.

MRP proposed a method to convert the resulting annual reliability portfolio from the LOLE study into monthly portfolios. MRP proposed removal of certain sets of resources to result in a monthly portfolio that would satisfy the single annual PRM to maintain reliability. This method may be labor intensive

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[93] MRP, September 14, 2022, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-14-2022-planning-reserve-margin-part-2/workshop-7_mrp_220914.pdf

[94] MRP, October, 2022. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_mrp_221006.pdf

because it is unclear how many iterations would be required. Alternatively, ED staff added additional hourly load on a monthly basis to achieve a similar result. This "load" could be considered as the reciprocal of supply that must be removed. In that manner, the monthly portfolio could be calculated in this manner, albeit with less precision. Additional detail is included in MRP's Proposal Package section of this report.

Middle River Power proposed that the LOLE study be refreshed every 2 to 4 years as load and the supply mix shift over time. Due to the fact that parties are waiting for the final portfolio from the refreshed LOLE study expected from Energy Division in January 2023, the conversion from traditional PRM to SoD PRM was not performed or tested. Additional discussion of PRM is located in the MRP's proposal package section.

f. EBCE Feasibility Adjustment, October 2022

Authors: EBCE

EBCE proposed a PRM Feasibility Adjustment step, in which the Commission would assess whether the portfolio requirements are feasible given the State's available resources. Where there is an infeasibility, the Commission would adjust the PRM requirement expectations to reflect that infeasibility. EBCE's proposal included:

- **Glide Path:** Forward-looking RA requirements should reasonably align with resources retained/developed in IRP.
- **Enforce Achievable Compliance**: Compliance enforcement should incent achievable outcomes. Compliance requirements are not useful when there are no alternatives (e.g., if there are insufficient resources to meet the PRM requirement).
- **Price-Gouging Risk**: Establishing an infeasible RA requirement gives RA sellers outsized market power. Given the constrained pipeline for new resources, the RA program should balance reasonable RA requirements (e.g., PRM) with customer affordability.

V. Comparison of the proposals

Authors: NRDC, ED, SCE, MRP

The proposals from SCE, Energy Division, NRDC, and MRP are generally aligned on most steps for PRM calibration. Proposals differ on the application of an annual PRM, as indicated in D.22-06-050, or the application of a more granular monthly PRM, which appears necessary for program accuracy based on further analysis by Energy Division.

Specifically, parties agree on the foundational approach involving the identification of an annual reliable portfolio using an LOLE study, to be performed by Energy Division, and the conversion of that portfolio through a heuristic tool mirroring the compliance rules (resource counting, load forecast, etc.) to determine the required PRM value that should result in the showing of a portfolio as reliable as the portfolio assessed in the LOLE study.

Figure 57: PRM Steps

Differences arise on the application of the PRM across months. Specifically, as discussed above, D.22-06-050 directed the use of a single annual PRM for all hours of all months, mirroring the current application of a single annual PRM to all months under the current RA framework. However, as identified by parties and analyzed by Energy Division, a single annual PRM presents challenges in effectively balancing reliability – maintaining a 0.1 LOLE standard across the year, and without introducing significant reliability risk in any given month – while avoiding excess procurement – avoiding a PRM which requires significantly more capacity than is required for reliability. As demonstrated by NRDC's monthly PRM calibration tool, it is possible to calibrate the PRM to specifically align with any given portfolio, including an annual portfolio, based on the specific counting rules and load forecast for any given month.

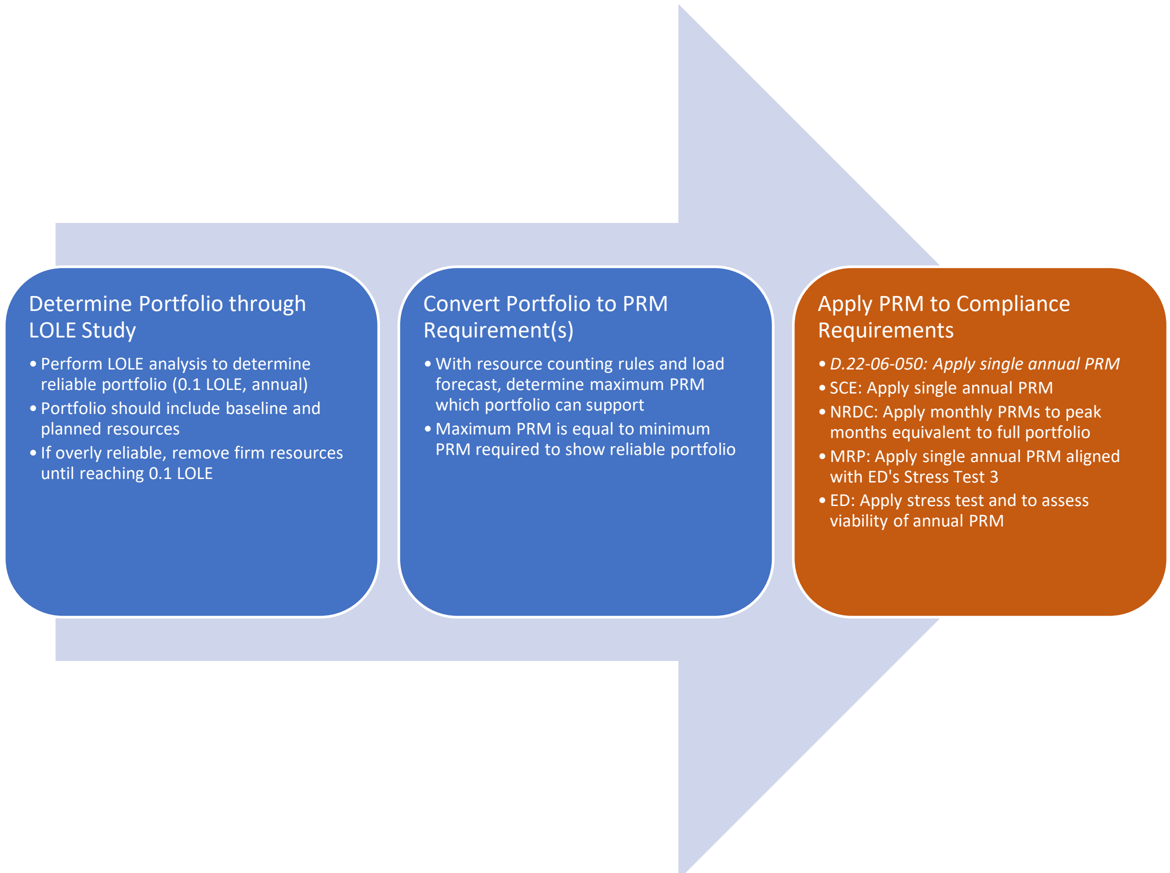
SCE, following the direction of D.22-06-050, has proposed the use of a single annual PRM, but has proposed an additional test to verify that the portfolio required under the monthly RA construct with a single PRM for all 24-hourly slices meets reliability standards. SCE has also suggested that for future LOLE analysis for Resource Adequacy PRM setting, the capacity expansion process provides a better match for the RA requirements.

NRDC advocated for the use of specific, monthly PRM values to better target a specific portfolio. NRDC proposed the use of monthly PRMs using all RA resources in any month with reliability risk, which it expects to be the peak summer months, and to use a generic annual PRM as proposed by SCE for non-at-risk months.

MRP proposed an annual PRM, aligned with the Commission Decision, that would maintain 0.1 LOLE for the entire year. This was presented by ED in stress test 3 results. MRP believes an annual PRM provides consistency for overall reliability in the long run and reduces costs for buyers.

Energy Division introduced a series of stress tests to assess the viability of an annual PRM applied to all months.

Figure 58: PRM Step Details



NRDC and EBCE introduced similar proposals which differ from other proposals – a reasonableness check to be performed by ED to ensure the portfolio identified by the LOLE study is reasonable and is balanced with other policy goals. As discussed by parties, it is possible that the portfolio identified by the LOLE study requires resources which will not exist for compliance, which may be in conflict with the Commission's intent to mitigate the risk of market power in the RA program. Alternately, ED may see other reasons for a reasonableness adjustment to the indicative portfolio, such as significant risk of planned resource delays or impending retirements just beyond the compliance horizon which necessitate retention of alternate resources as a bridge to the planned retirements.

VI. Consensus and non-consensus items

Authors: NRDC, ED, SCE, MRP

As discussed above, the general framework for PRM calibration has reached consensus, including the following steps:

- Determine Portfolio through LOLE Study
    - Perform LOLE analysis to determine reliable portfolio (0.1 LOLE, annual)

  Include baseline and planned resources in the portfolio
    - If overly reliable, remove firm resources until reaching 0.1 LOLE
- Convert Portfolio to PRM Requirement(s)

- With resource counting rules and load forecast, determine maximum PRM which the portfolio can support
- Maximum PRM is equal to minimum PRM required to show reliable portfolio

While the general framework for converting the LOLE portfolio to a PRM using a heuristic tool is a consensus item, from a practical perspective, parties have been using two distinct tools – the NRDC Tool and the SCE Tool. NRDC's tool, which performs a PRM calibration on the aggregate capabilities of generic resource classes, has been used by Energy Division for their analysis and calibration efforts in the workshop series. SCE's tool, which performs a PRM calibration based on the individual resource characteristics defined within the model, more closely matches the needs outlined in D.22-06-050 to incorporate use limitations for specific thermal units. The Commission could opt to move forward with either tool, or integrate the tools, so long as the PRM calibration logic and data is properly aligned with the adopted compliance rules (e.g., inclusion of use limitations, storage charging constraints).

The final step, converting an annual portfolio to monthly requirements, has yet to reach full consensus. This non-consensus appears to be driven largely by the reality that the RA program, despite being a monthly requirement, has not previously confronted the need to define specific monthly requirements to balance reliability throughout the year. Proposals for this final step include:

- Apply PRM to Compliance Requirements
    - *D.22-06-050: Apply single annual PRM*
    - SCE: Apply single annual PRM calibrated to highest load day
    - NRDC: Apply monthly PRMs to peak months equivalent to full portfolio
    - MRP: Apply single annual PRM calibrated to maintain a 0.1 LOLE for the entire year
    - ED: Apply stress tests to assess the viability of an annual PRM applied to all months

The final area of non-consensus is the proposals from NRDC and EBCE to direct Energy Division to assess the reasonableness of the portfolio and adjust as necessary to meet other policy outcomes, to the extent the identified portfolio is in conflict. This proposal, submitted late in the process, elicited significant discussion on whether ED *should* exercise discretion or even have authority to exercise it if, for example, the portfolio identified requires resources which do not exist; parties are invited to comment on whether ED *should have* discretion.

VII. Questions for parties

Authors: NRDC, CAISO

- Do parties have recommendations on the general technical process for converting the resource portfolio to a PRM Value?
- Do parties have recommendations or concerns with regard to what conversion tool Energy Division should use to convert the results of the LOLE study?
- Should the annual portfolio requirement be adjusted if the LOLE study implies more resources are needed than are available?
- How should monthly PRM be resolved?
    - Is it reasonable to accept that a PRM based on the peak load month is sufficient for the rest of the year?

   - Does a single annual PRM erase the added precision that SOD reform intends to capture?
- Reliance on non-RA resources in non-summer months is implicit in relying on a PRM based on the peak (summer) month. It is not likely that all resources in the annual portfolio will be contracted or shown for all non-peak months.
   - Does CAISO lose access to must offer obligations for resources necessary to meet reliability in non-peak months if they do not have an RA contract?
   - Does an annual PRM based on a single month affect generator fixed cost recovery?
- Should the annual portfolio requirement be adjusted if the LOLE study implies more resources are needed than are available?

VIII. References

- SCE 8/17 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2022-planning-reserve-margin/workshop-4_sce_220817.pdf
- NRDC 8/17 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2022-planning-reserve-margin/workshop-4_nrdc_220817.pdf
- Energy Division 8/17 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2022-planning-reserve-margin/workshop-4_ed_220817.pdf
- MRP 8/17 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2022-planning-reserve-margin/workshop-4_mrp_220817.pdf
- SCE 9/14 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2022-planning-reserve-margin/workshop-4_sce_220817.pdf
- Energy Division 9/14 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-17-2022-planning-reserve-margin/workshop-4_ed_220817.pdf
- MRP 9/14 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-14-2022-planning-reserve-margin-part-2/workshop-7_mrp_220914.pdf
- SCE 9/29 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-29-2022-test-year-follow-up-on-remaining-issues/workshop-9_sce_220929.pdf

- NRDC 10/6 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_nrdc_221006.pdf
- CAISO 10/6 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_caiso_221006.pdf
- Energy Division 10/6 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_energy-division_221006.pdf
- MRP 10/6 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_mrp_221006.pdf
- EBCE 10/6 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_ebce_221006.pdf

ix. Test Year Details

Authors: WPTF, with support from EBCE, CalCCA, SCE, MRP

I. Background

In D.22-06-050, the Commission held: "Given the complexities of implementing a new statewide RA framework, we find it prudent to consider a test year in 2024 to allow additional time for implementation and potential adjustments. This would result in full implementation of the new RA framework to the 2025 RA year."[95] The Commission therefore directed parties to develop proposals for a 2024 test year as part of Workstream 2.[96]

Additionally, while declining to consider hourly resource or load obligation trading for inclusion in the 24-hour framework at this time, the Commission stated that it may consider such proposals "if transactability and inefficiency concerns arise once the new 24-hour framework is implemented…."[97] During the workshops, parties discussed how the transactability and inefficiency concerns cited in D.22-06-050 could be identified during the test year.

Test year details were the subject of presentations made in the workshops held on September 14 and October 6, 2022, as well as a panel discussion that took place during the September 29, 2022, workshop. Parties making presentations on test year details included the East Bay Community Energy Authority (EBCE), Middle River Power, LLC (MRP), and Southern California Edison Company (SCE). Panel discussion participants included Nuo Tang, Director – Asset Management West, MRP, Eric Little, Director of Regulatory Affairs, California Community Choice Association (CalCCA),[98] Jamie Rose Gannon, Regulatory Energy Analyst, Energy Division, Simone Brant, Regulatory Analyst, Energy Division, Cristy Sanada, Manager, California Regulatory Affairs, California Independent System Operator Corporation (CAISO), and Abdul Mohammed-Ali, Operations Engineering Resource Adequacy Lead, CAISO.

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[95] D.22-06-050 at 76.
[96] *Id.* at 107 and 109.
[97] *Id*. at 97 and 114.
[98] Eric Little was not speaking on behalf of CalCCA during the test year panel discussion.

II. Issues

At the October 6, 2022, workshop, MRP identified the following issues related to the test year and its implementation:

- Timing and details of year-ahead and month-ahead LSE showings for the test year
- Need for Energy Division to monitor showing templates and fix issues as needed
- Possible need for changes to CAISO systems

During the panel discussion at the September 29, 2022, workshop, panelists discussed showing and compliance issues, including the timing of LSE showings and the CAISO's market simulation, as well as CPUC processes and templates that will need to be modified for the test year. Panelists also discussed whether LSEs would "show" the same RA resource portfolios for both their "normal" RA showings and their SOD showings. Lastly, panelists discussed criteria for assessing the test year's results and additional measures that will be needed for full implementation of the SOD framework for the 2025 compliance year.

During the panel discussion, EBCE and Mr. Little expressed the need to test both resource sufficiency and the need for hourly transactability during the test year to ensure LSEs have the ability to meet requirements under the new RA framework. The SOD framework will change the way resources are counted and shown (e.g., using exceedance for wind and solar counting rather than ELCC, showing storage based on its capacity and duration as shown by the LSE, showing excess capacity to charge storage, etc.). It will also change the way compliance is assessed (i.e., assessing every hour rather than a single peak hour). EBCE and Mr. Little recommended that both of these changes, combined with recent experiences of RA market tightness, necessitate two checks to occur during the test year:

- **Resource Sufficiency Assessment:** Test that, under the new protocols for setting RA requirements and the new resource counting methodologies, there are sufficient RA resources for LSEs to meet requirements; and

- **Hourly Transactability Needs Assessment:** Test that, under the new hourly RA compliance obligations, LSEs can efficiently meet their requirements without hourly trading of resources or load.

In subsection IV, EBCE and Mr. Little present their proposals for conducting these assessments, as well as the steps following the results of each assessment.

III. Presenters and Dates

- Workshop 7: September 14, 2022
  - John Newton, EBCE, made a presentation on transactability
- Workshop 9: September 29, 2022
  - Brent Buffington, SCE, made a presentation on test year tools
- Workshop 10: October 6, 2022
  - John Newton, EBCE, made a presentation on resource sufficiency and transactability
  - Nuo Tang, MRP, made a presentation on test year implementation details

IV. *Proposal Summaries*

a. SCE

Authors: SCE

At the September 29, 2022, workshop, SCE presented a comprehensive set of test year tools such as a resource database, LSE showing tool, and CPUC verification tool. These tools are further discussed in the Compliance Tools section of this report. To maintain consistency with current CAISO RA processes, SCE suggested that the resource database and 24-hourly resource shapes be expressed in terms of single-monthly NQC. This will allow the test year showings to be 24 hourly slices but also provide LSEs a connection with the CPUC and CAISO showings under the current RA program in 2024.

a. Eric Little

Authors: Eric Little

At the September 29, 2022, workshop, Eric Little, Director of Regulatory Affairs at CalCCA, speaking for himself rather than the organization, participated in a panel discussion on elements that the Commission needs to address during the test year.[99] Similar to EBCE's proposals as described in subsection c below, Mr. Little proposed that the test year should consider whether there are enough RA-eligible resources available to meet the SOD RA requirements. The SOD framework will shift resource counting from ELCC-based counting to exceedance-based counting. It will also shift the setting of system RA requirements from one requirement based on the CAISO gross peak to 24 hourly requirements based on individual LSE load shapes. These modifications will inevitably change what the capacity resources count for and the level of resources LSEs must show to meet their compliance obligations. This, coupled with the fact that LSEs currently face unprecedented RA market tightness, necessitates an assessment during the test year to ensure there are enough RA-eligible resources to meet LSEs' RA requirements.

Before the first compliance year, Mr. Little proposes that the Commission test:

1. Whether the aggregate of system-wide RA-eligible resources and RA imports, as measured using the new SOD counting rules, can meet total system RA requirements under the new hourly slice framework; and
2. Whether individual LSEs can meet their own requirements given the level of transactability contemplated for initial SOD implementation, which would not allow LSEs to buy and sell resources or load obligations on an hourly basis.

If test one fails, meaning total resources cannot meet the aggregate hourly RA requirements, Mr. Little proposed that the Commission adopt an RA waiver process for system RA that would give the Commission discretion not to penalize LSEs who can demonstrate they exerted commercially reasonable efforts to procure their system RA requirements, similar to the existing waiver process in place for local RA. This is because the RA program is not intended to result in new resource build. Instead, it is the role of the IRP proceeding to result in new resource procurement, while the RA program should require LSEs to contract with existing resources to ensure they are dedicated to serve California load.

[99] Eric Little was not speaking on behalf of CalCCA during the test year panel.

If test two fails, meaning transactability issues are identified that inhibit LSEs' ability to efficiently meet their RA obligations, the Commission must immediately convene a process within the RA proceeding to develop hourly load and/or resource trading for implementation for RA compliance year 2025.

b. EBCE

Authors: EBCE

At the October 6, 2022, workshop, EBCE proposed that during the test year, the Commission should test whether meeting the PRM established for the slice-of-day framework is feasible, given the RA resources available to meet the Commission's RA requirements. If there is an identified infeasibility, EBCE proposed that the Commission adjust the PRM (and the associated RA requirements) to reflect the reality of the resources available to provide RA. Beyond the test year, EBCE proposed that forward-looking RA requirements should reasonably align with resources retained or developed in the Commission's IRP program. Additionally, the RA program should enforce achievable compliance, but compliance requirements are not useful or do not result in increased reliability when there are no alternatives to meet those requirements (e.g., if there are insufficient resources to meet requirements under the new PRM).

This proposal stems from the concern that sufficient RA resources may not exist to meet the PRM in the near term. If that reality is not taken into account when setting overall RA requirements, LSEs could be left with unmeetable requirements. In its presentation, EBCE noted that establishing infeasible RA requirements presents a significant price-gouging risk because it gives RA sellers outsized market power. Given the constrained pipeline for new resources, EBCE recommended the RA program should balance reasonable RA requirements (e.g., in setting the PRM) with customer affordability.

EBCE also proposed the Commission conduct a resource feasibility assessment during the test year using aggregate LSE showings. The assessment would evaluate the need for inter-LSE hourly transactability as (1) a transitional benefit to smooth the adoption of the 24-hour framework while LSE portfolios adapt and (2) an enduring element of the program to improve utilization of existing resources across multiple LSE portfolios.

At both the September 14 and October 6, 2022, workshops, EBCE made a presentation on considering hourly transactability as part of the 2024 test year and in preparation for the 2025 implementation of the new RA program. EBCE noted that hourly transactability is not currently expected to be a feature available at the start of implementation of the new RA program; however. EBCE proposed that the 2024 test year process should be able to consider hourly transactability as a useful tool to support the success of the new RA program without hindering the transition.

To that end, EBCE proposed that the Commission analyze not only individual LSE showings under the 24-hour slice-of-day paradigm, but also consider *in aggregate* (i.e., both at and below the full system view) how LSE portfolios satisfy RA obligations as part of the 2024 test year process.

Figure 59: Individual LSE Showings

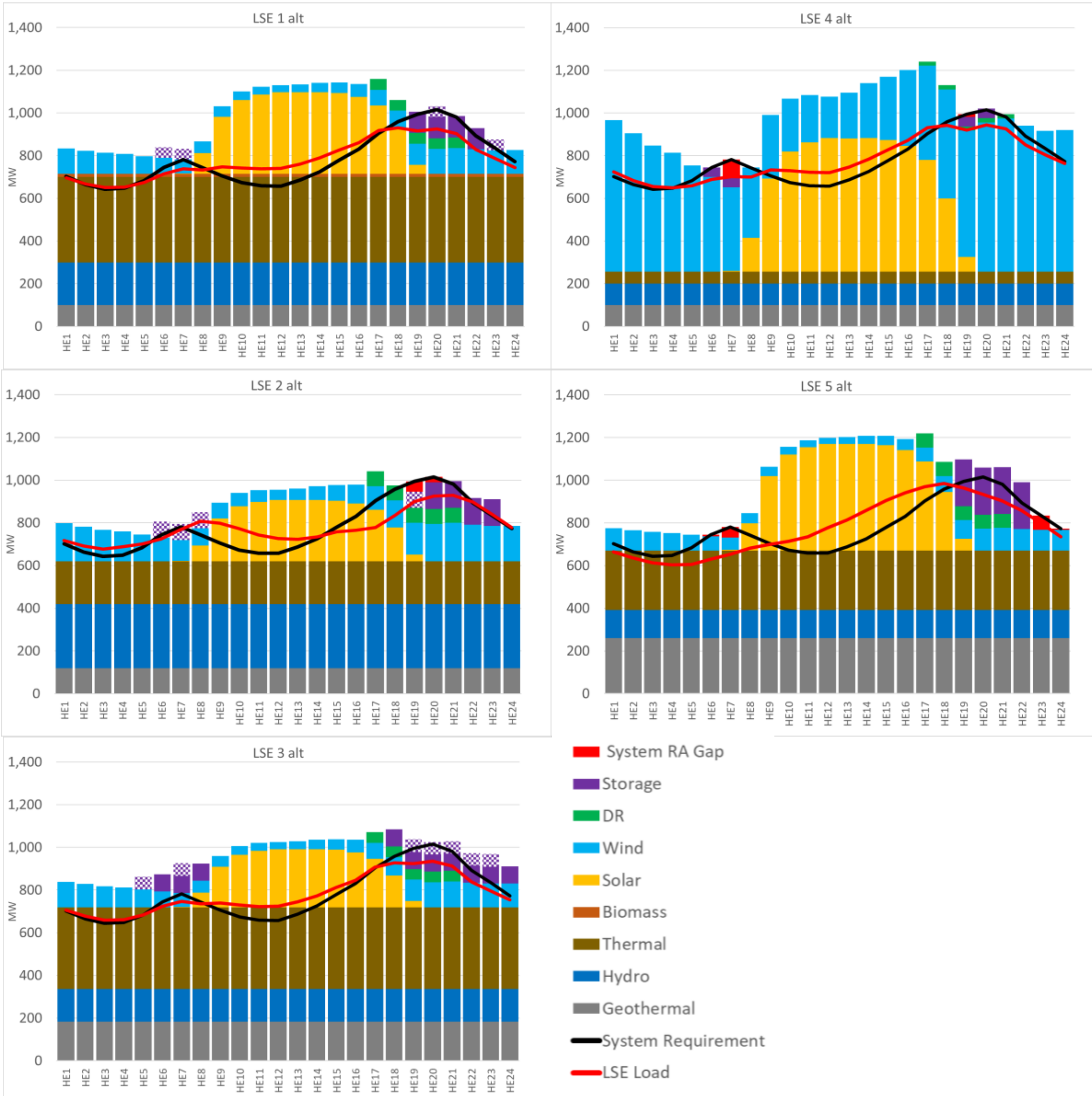
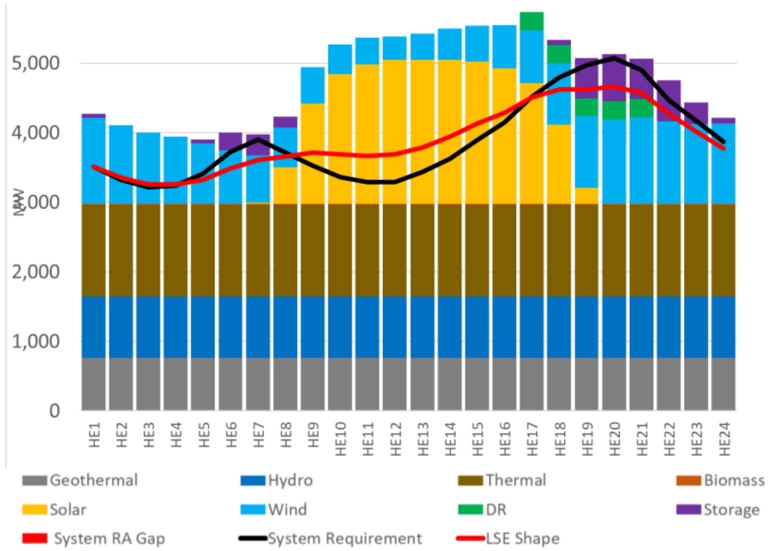

LSE 1 alt
LSE 4 alt
LSE 2 alt
LSE 5 alt
LSE 3 alt
MW
1,400
1,200
1,000
800
600
400
200
0
HE1 HE2 HE3 HE4 HE5 HE6 HE7 HE8 HE9 HE10 HE11 HE12 HE13 HE14 HE15 HE16 HE17 HE18 HE19 HE20 HE21 HE22 HE23 HE24
System RA Gap
Storage
DR
Wind
Solar
Biomass
Thermal
Hydro
Geothermal
System Requirement
LSE Load

Figure 60: Aggregated LSE Showings



Under the SOD paradigm, each LSE will need to show that it has sufficient RA-eligible resources to satisfy its RA obligations (i.e., CEC-specified load + PRM) in each slice of the 24-hour period for each 'month' as represented in Figure 59, above. Each LSE's RA obligation shape will be specific to that LSE. Based on the resource counting rules that will determine how LSE portfolio resources can be shown or allocated for each slice,[100] LSEs likely will have long and short positions in various slices of the day. Some LSEs may have long positions, while other LSEs have short positions. However, when LSE RA obligations and resource portfolios are viewed in aggregate there may be sufficient resources to satisfy the RA obligation as represented in Figure 60, above. Presumably, no individual LSE will have sufficient information about other LSE portfolio positions or RA obligations to ascertain the extent to which an aggregated view will show that portfolio resources satisfy RA obligations, but *the Commission will have this ability* via the many individual LSE showings it will receive.

EBCE noted that hourly transactability could have transitional value as well as enduring value for the new RA program:

- There may be a *transitional need* for hourly transactability. As LSEs pivot from the current RA program to the 24-hour SOD RA program, compliant resource portfolios under the old paradigm may not translate smoothly to the new paradigm. Consequently, LSEs' portfolios may be long or short during different slices of the representative days. As LSE portfolio management adapts to the new RA program and new resources come online, the need for hourly transactability may lessen.

- There may also be an *enduring need* for hourly transactability. Hourly transactability would allow for a more efficient utilization of existing resources to meet RA obligations, thereby avoiding risk of over-procurement and maintaining customer affordability.

[100] See, e.g., counting rules for wind and solar resources at 6, hybrids at 8, long-duration storage at 9, etc.

EBCE in its presentation and CalCCA in discussion noted that alternatives to hourly transactability may be insufficient. While LSEs currently can transact for bundled RA capacity to close long or short positions, these transactions would affect all 24 slices and may not be viable where LSEs need these resources to satisfy peak or net-peak demand requirements. Similarly, while energy storage or other use-limited resources may be transacted to right-size LSEs' portfolios to their individual RA obligations, there may not be sufficient available resources to meet LSE demand given current resource availability and extended development timelines for new resources.

c. MRP

Authors: MRP

During the October 6, 2022, workshop, MRP made a presentation on details of test year compliance showing process for LSEs and the CPUC. MRP also addressed issues that impact CAISO's operations and the supplier community. For example, if CAISO software changes are required, then suppliers would also need to test the new software. The CAISO is expected to start its own stakeholder initiative process to review necessary changes.

MRP highlighted an issue that translates the 24-hourly slice showings to the CAISO's current stacking structure where no changes are made to the CAISO's systems: If the CAISO does not modify its processes, then the method for calculating the shown capacity would result in over-stacking of resources to meet RA obligations (Demand + SOD PRM) that is too low. Additionally, the CAISO must still manage a separate RA program with the same software for non-CPUC jurisdictional LSEs that do not use the 24-hourly slice framework. Finally, MRP provided test year exit criteria for measuring whether the SOD framework is implementable and what modifications, if any, are necessary as the result of the test year. Please see MRP's slides for more details.

V. Consensus and non-consensus items

Parties did not reach consensus on whether the test year is a check on resource sufficiency and the need for hourly transactability or simply a check on the administrative process/implementation.

In addition to EBCE presenting its proposal that the test year process consider aggregations of LSE showings as an indication of hourly transactability value, Peninsula Clean Energy (PCE) and San José Clean Energy (SJCE) expressed support for considering hourly transactability as part of that process. EBCE, responding to SCE, noted that hourly transactability is consistent with LSEs' obligation to maintain resource portfolios to satisfy their RA obligations. However, this is not a consensus item.

The Public Advocates' Office (Cal PA) noted that supporting hourly transactability as a transitional tool is different from hourly transactability as an enduring feature of the new RA program.

VI. Questions for parties

- What are the most important metrics and considerations for determining whether the test year has been a success and/or what changes to the SOD framework may be needed before full implementation?
- If the test year identifies problems with the SOD framework's implementation, what process should be used for rectifying those problems?
- To what extent would hourly transactability serve a transitional or an enduring need to support the success of the new RA program?

- What are the opportunities and challenges associated with transactability of load obligation as compared to resources on an hourly basis? While not considered at length in the workshop, hourly transactability could take the form of *load obligation* transactions or *resource* transactions in a given slice of the 24-hour period.

VII. References

- EBCE Transactability Proposal – September 14, 2022, Discussion and Presentation
- EBCE Resource Sufficiency Proposal – October 6, 2022, Discussion and Presentation
- CalCCA Proposal – September 29, 2022, Discussion during the Test Year Panel
- MRP Proposal – September 29, 2022, Discussion during the Test Year Panel and October 6, 2022 Presentation
- SCE Proposal – September 29, 2022, Presentation

x. MCC Buckets

Authors: SCE, with support from CESA, collaboration with ED

I. Background

The historical purpose of the maximum cumulative capacity (MCC) buckets was to prevent over-reliance on use-limited resources for meeting peak load. The MCC buckets utilize a historical load duration curve to establish maximum cumulative percentages of an LSE's monthly procurement obligation that can be met with use-limited resources or contracts that provide less than 24x7 hours of availability. The MCC bucket thresholds are typically based on an average gross load duration curve from the past three years and the threshold for demand response (DR) was based on the difference in load between peak load hour and the 25th highest load hour for the average summer month.

In Decision 22-06-050, the Commission found that full removal of the MCC buckets would eliminate the monthly availability requirements and suggested that it may still be necessary to include some availability requirement for resources with monthly use limitations under the SOD framework, particularly for DR and imports. The decision also offered some potential solutions. DR resources could be required to be available Monday through Saturday, for four consecutive hours during the AAHs, and at least 24 hours per month from May through September. Imports could be required to deliver energy for at least four hours during the AAHs from at least Monday through Saturday through the compliance month, consistent with the hours specified in the contract.

The Commission also directed the parties to develop proposals for the 2024 test year, especially whether 4-hour and 8-hour standalone storage could count in bucket 4 so long as the LSE can show it can charge the storage resource.

II. Issues

Currently, MCC buckets address over-reliance on use-limited resources, both daily and monthly, to meet peak load needs. The 24-hour SOD framework addresses daily use limitations but not monthly use limitations, so it is imperative to address monthly limitations before eliminating MCC buckets.

There is also a need to address concerns regarding the MCC bucket limits for the 2024 test year.

III. Presenters and Dates

- Workshop 5: August 23, 2022
    - Energy Division (ED)
    - Southern California Edison (SCE)
    - California Energy Storage Alliance (CESA)

IV. Proposal Summaries

a. Energy Division

For DR, Energy Division staff believes that while it makes sense to set some availability requirements, DR resources are still fundamentally use-limited and there should continue to be a cap on the amount of DR that can be used to meet RA requirements. Currently, the MCC bucket threshold for DR is based on the difference in load between the peak load hour and the 25th highest load hour for the average summer month. However, Energy Division staff suggested that the methodology for setting the DR procurement limits should be adjusted for the SOD framework by restricting counting to the Availability Assessment Hours (AAH) when determining the peak load hour and the 25th highest load hour. (Assuming that DR is supposed to serve load during the 24 highest load hours each month, the marginal load between the 25th and 24th highest hours should be included.) ED staff's presentation was based on the following assumptions:

- Summer months are May through September
- DR should be available during the Availability Assessment Hours (AAH)
    - AAHs for all summer months are HE 17-21
- DR should be available at least 24 hours per month
- DR should serve load during peak hours
- DR is usually dispatched during high-priced hours

ED staff presented the following methodology for setting SOD-adjusted DR procurement limits:

1. Calculate hourly load profiles for last 3 years (gross or net)
2. For each year…
    a. Rank the hours from highest to lowest load for every HE in each month
    b. Calculate the "average summer month", with hours ranked by HE
3. Calculate the "average summer month" for last 3 years, with hours ranked by HE
4. Find the peak (1st highest) load, L_1, within the AAHs for the average summer month
5. Find the 25th highest load, L_{25}, within the AAHs for the average summer month
6. RA procurement limit for DR = $\frac{L_1 - L_{25}}{L_1}$

ED staff also showed how the SOD adjustment would change the DR procurement limits compared to the status quo. These values are shown in Table 16 below. In this calculation, ED staff used gross and net load for 2019 through 2021. However, ED staff also recognizes that drastically increasing the procurement limit for DR could raise reliability concerns based on past DR performance. In addition, the program hours for DR do not always align with AAHs. In terms of using gross or net load, gross load would be more consistent with the rest of the RA framework because RA requirements are based on gross load. However, in practice, there is a greater correlation between DR dispatches and net load because high net load tends to correspond to higher prices.

Table 16: Comparison of methodologies for setting DR procurement limits under SOD

Methodology	DR Procurement Limit	Increase from Status Quo
Gross load 2019-2021, avg. summer month **(status quo)**	8.5%	N/A
Gross load 2019-2021, avg. summer month, restricted to AAH	9.9%	+1.4%
Net load 2019-2021, avg. summer month, restricted to AAH	14.4%	+5.9%

Note: Numbers in table above are slightly different than those shown during the workshop due to change from 24th highest load to 25th highest load.

During the workshop, some participants suggested that the DR procurement limit should vary by hour. However, after considering the implications, ED staff believes that the reliability benefits of variable limits are unclear. Variable limits could result in lower or *higher* limits for some hours than a single limit applied consistently across all hours.

For import resources, ED proposed a requirement to deliver energy for at least four hours during the AAHs from at least Monday through Saturday through the compliance month, consistent with the hours specified in the contract. It could be self-scheduled or bid between $0 and negative $150 per MWh to align with the bidding requirements established in D.20-06-028 tied to hours specified in contract and RA showing.

b. CESA

CESA suggested considering a minimum requirement for MCC buckets rather than a maximum requirement by setting a minimum requirement for assets with availability above 4 hours to minimize multi-day reliability risks. It also opined that MCC requirements should vary by LSE-specific load shape.

c. SCE

SCE mentioned that 24-hour slice framework incorporates many limitations but there is a need to consider non-daily limits of resources such as DR, import resources, dispatchable resources with monthly limitations, etc.

For 2024, SCE indicated there is a need to create a bridge during the test year from the current RA construct to the 24-hour slice framework. SCE proposed to count standalone energy storage resources in MCC bucket 4 in 2024 if they pass the energy sufficiency test. Many LSEs are expected to be long on standalone energy storage resources and hence MCC bucket 4 treatment for storage is needed to avoid over-procurement under existing MCC rules. SCE proposes to retain all other MCC bucket rules without the daily limitations for the 2024 test year.

V. Questions for parties

Demand Response showings across the slices:

- How many hours should DR be required to be available each month?
- Should procurement limits be determined using gross or net load?
- Should procurement limit (%) be applied to the MW required for each slice or to the total MW required across all slices?
- Should there be an option to count DR resources which could provide load drop outside the AAH?

2024 Test Year:

- Do parties support SCE's proposal for 2024 to allow LSEs to count storage in MCC bucket 4 if they pass the energy sufficiency test in their SoD test year showing?

VI. References

- Energy Division 8/23 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-23-2022-planning-reserve-margin/workshop-5_ed_220823.pdf
- SCE 8/23 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-23-2022-planning-reserve-margin/workshop-5_sce_220823.pdf
- CESA 8/23 Presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-23-2022-planning-reserve-margin/workshop-5_cesa_220823.pdf

c. CAISO and Commission Validation and Compliance

i. Introduction

Authors: CLECA

Workstream 3 is to address the following:

1. Confirm elements of CAISO and Commission validation and compliance that do not require modification in the near term.
2. Identify and resolve administrative changes to the RA program at both CAISO and the Commission (e.g., must-offer reporting, outage substation).
3. Elimination of the flexible RA requirements.

CAISO and Commission Validation: The CAISO may need more than the current single monthly showing for the NQC for RA based on the peak hour. QC and showing values based on the peak hour may no longer be sufficient for CAISO processes. If utilizing values from CPUC SOD reform (*e.g.*, hourly QC values for VERs), CAISO will likely need values from at least two hours -- possibly the peak and the maximum showing value. However, exact values and hours have not yet been decided.

Administrative Changes: Given the many uses of the NQC is the CAISO's processes, a CAISO stakeholder process will be needed to make changes to its processes and consider the impact on other Local Regulatory Authorities that are not CPUC-jurisdictional.

Elimination of the Flexible RA Requirement: The Energy Division stated that it would like to simplify the flexible capacity assessment. However, the flexible capacity requirement is part of the CAISO tariff, and a new CAISO stakeholder process would be required to eliminate it.

ii. CAISO validation and compliance processes and administrative changes to the program

Authors: CAISO, with support from SCE, SVCE

I. Background

Authors: CAISO

CPUC Decision (D).22-06-050 Appendix A suggests that under the CPUC's 24-hour resource adequacy framework, all resources will continue to have single monthly NQC values based on the peak hour:

> **Profiles and Net Qualifying Capacity (NQC)**
> All resources will still have a single monthly NQC value representing the deliverability adjusted peak-hour contribution. Most resource types will continue to utilize this NQC for their showing (and for CAISO deficiency determinations) while solar and wind will utilize hourly profiles and NQC in their Commission RA showings. NQC for wind and solar will be based on peak hour deliverable capacity based on their profile for that hour.

The CPUC directed parties to address issues related to CAISO compliance and validation in Workstream 3.

II. Issues

Authors: CAISO

Under the CPUC 24-hour SOD RA framework resources such as wind and solar, and potentially demand response, will shift from single monthly QC values to hourly QC methodologies. In workshops, parties have also advocated for flexibility in how storage discharge is spread across the day. Despite changes in CPUC RA counting and showings for certain resource types, the CAISO must continue to need QC values and resource showings that will allow it to continue to administer key resource adequacy processes for all its LRAs.

In the CAISO's September 21, 2022, presentation, the CAISO provided an overview of its current RA processes and outlined potential challenges the CAISO could face under the CPUC's 24-hour framework given CPUC changes to resource counting and showings.[101] Under the CAISO's current RA framework, the CAISO uses a single monthly QC value per resource from LRAs. These QC values are used to

[101] CAISO 9/21 presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-21-2022-cpuc-caiso-processes/workshop-8_caiso_220921.pdf

establish the CAISO's NQC list. The CAISO defers to LRAs' QC methodologies under the current CAISO tariff. QC values from LRAs may be adjusted by the CAISO for deliverability or other reasons such as Pmax testing to establish NQC values.

In monthly and annual RA showings, LSEs and suppliers currently show single RA values for each resource to the CAISO. These RA showings are capped at resource NQC values. RA showings are used in the following downstream CAISO processes:

Table 17: How RA Showing Values Are Used Today

CAISO process	How RA showing values are used today
System assessments	RA shown by LSEs is compared to coincident peak demand plus planning reserve margin, to determine whether LSEs meet overall system and individual system resource adequacy requirements
Local assessments	Resources are dispatched in local assessments based on the amount of the resource shown to the CAISO (shown resource adequacy as a percentage of NQC) to determine whether LSEs meet collective and individual local capacity requirements
Outage substitution	Outage substitution obligations are based on shown resource adequacy values
Must offer obligations	Must offer obligations are based on shown resource adequacy values

Under the CPUC 24-hour SOD RA framework, QC values from a select hour and RA showings from a single hour may not provide sufficient information for the CAISO to administer its downstream processes. For example, under the CPUC 24-hour RA framework, wind and solar QCs may be zero in a single hour and/or resources may not be shown across all hours of the day to the CPUC. Using QC values and showings from a single hour may present the following challenges for CAISO processes:

Table 18: Challenges for CAISO Processes

CAISO process	Challenges
NQC list	Zero MW NQC values create challenges in downstream processes. Zero MW QC values will translate to zero MW NQC values. Resources with zero MW NQC would have no RA value in CAISO systems. The CAISO would not be able to discern, for example, how much of a resource was shown as RA and therefore how to dispatch a resource in local assessments.
Local assessments	If a resource is not shown or has a zero MW NQC value at peak, then CAISO cannot derive the percent of a resource shown in order to dispatch the resource in local assessments
Outage substitution	If a resource is not shown or has a zero MW NQC value at peak, it is uncertain how CAISO would apply an outage substitution obligation to the resource
Must offer obligations	If a resource is not shown or has a zero MW NQC value at peak, it is unclear how CAISO would apply a must offer obligation to the resource

III. Presenters and Dates

Authors: CAISO

- Workshop 8: September 21, 2022:
    - The CAISO presented on CAISO compliance issues
- Workshop 9: September 29, 2022:
    - SCE proposed an option for CAISO compliance
- Workshop 10: October 6, 2022:
    - Silicon Valley Clean Energy (SVCE) presented on Maximum Import Capability (MIC) issues related to CAISO compliance
    - MRP presented on issues related to the use of maximum values for CAISO compliance

IV. Proposal Summaries

a. CAISO

Authors: CAISO

In the September 21 workshop, the CAISO presented a potential option to operationalize the CPUC's RA reform that could ensure the CAISO's main RA processes can still function as they do today.[102] CAISO's five main RA processes impacted by QC and NQC values are:

- Developing the NQC List
- System assessments
- Local assessments
- Must offer obligations
- Outage substitution obligations

In its presentation, the CAISO showed that QC values based on the peak hour, as suggested by CPUC Decision (D).22-06-050, could be problematic for wind and solar resources if resource QCs are zero MW at the peak hour. This is because several CAISO processes use NQC values as a reference point. For example, the CAISO calculates the percent of a resource shown as RA to inform resource dispatch in local capacity assessments by dividing NQC by shown RA. The CAISO also uses NQC values to calculate the MWs of non-RA capacity of a resource, which indicates whether a portion of a resource is eligible for substitute capacity or CPM.

The CAISO also showed that if LSE showings are based on the peak hour, then CAISO would not have insight into resources not shown to the CPUC at the peak hour. The CAISO must have visibility into all resources used to meet the reliability of the CPUC portfolio in order to apply RA rules to these resources and dispatch resources in local capacity assessments.

The CAISO presented a potential option which could give CAISO sufficient information to administer its current RA processes and provide CAISO insight into the entire CPUC RA fleet. The CAISO option also aimed to align CAISO and CPUC compliance checks at the system coincident peak hour. Under this option, the CAISO would consume more than one value from the CPUC processes. The CAISO suggested

[102] CAISO 9/21 presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-21-2022-cpuc-caiso-processes/workshop-8_caiso_220921.pdf

the following data points from CPUC processes could be transmitted to the CAISO and feed into various CAISO processes:

- Non-zero QC values for each resource from the CPUC to develop the NQC list
- Maximum showing values from LSEs to ensure CAISO visibility into the entire CPUC RA fleet
- Peak showing values from LSEs to use in CAISO system assessments

The CAISO suggested that the CPUC consider options other than peak hour values to establish the NQC list and use for CAISO compliance. The CAISO suggested that parties should explore other CAISO compliance options in the CAISO's forthcoming RA stakeholder process which will include operationalizing CPUC RA reform. The CAISO noted that potential CAISO compliance options would likely require some systems and process changes and explained that other LRAs must be apprised of any system or process changes at the CAISO before changes are adopted. The CAISO also noted that any system and process changes and the timing of such changes are subject to further scoping and assessment at the CAISO.

b. SCE

Authors: SCE

At the September 29 workshop, SCE proposed that the CAISO continue to use a single showing value from LSEs and suppliers, which would result in limited changes to CAISO systems and processes. SCE proposed that CAISO continue to use the 'System RA MW' value from SCE's proposed LSE showing template.[103] This value would represent the same single monthly QC value for resources as today. For solar resources, for example, this value would reflect the current single-monthly solar ELCC percentage. SCE proposed retaining current resource counting for wind and solar (*i.e.,* ELCC values) for use in CAISO processes until the CAISO otherwise changes its compliance framework via a CAISO stakeholder process.

c. SVCE

Authors: SVCE

On October 6, SVCE explained that the value used to set NQCs for VERs (wind in particular) has implications for Maximum Import Capability (MIC).[104] SVCE showed that the counting value for wind will impact the NQC value for resource-specific resource adequacy imports and thus the amount of MIC that LSEs must hold to support resource-specific imports. SVCE noted that if maximum SOD counting values across 24 hours are used as the basis for VER NQCs then this would require LSEs to secure more MIC to support VER-backed resource-specific imports, tightening the supply of MIC.

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[103] SCE Slice of Day 24 Slice Model 9-21-22: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/ra-reform-excel-workbooks/sce-slice-of-day-24-slice-model-20220921.xlsx
[104] SVCE 10/6 presentation: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_svce_221006.pdf

As potential alternatives to a maximum slice value, SVCE asked whether peak load slice MWs or a "25th Value", potentially based on current ELCC values, could be the basis for wind and solar NQC values used to inform counting for resource-specific imports, and thus MIC.

V. Comparison of the options/proposals

Authors: CAISO, SCE

SCE's proposal to retain a single-monthly QC value in both the CPUC and CAISO processes would require minimal changes to CAISO processes and systems while allowing CPUC showings to reflect 24 slices. For most resource types, the single monthly QC value will be equal to the maximum counting value under the CPUC 24-hour framework (*e.g.,* thermal, geothermal, biomass, storage, hydro). For wind and solar, QC values would be based on existing ELCC values today, and resource profiles under the CPUC 24-hour framework can be adjusted to reflect hourly counting relative to the current single-monthly ELCC value for each technology.

The option presented by the CAISO would require CAISO system and process changes in order to consume multiple values from CPUC processes and divert different values to different downstream CAISO processes. In contrast to SCE's proposal, CAISO's option would utilize new QC values from the CPUC's 24-hour framework within existing CAISO processes, which could help mitigate potential discrepancies between peak hour compliance at the CPUC and system peak compliance at the CAISO.

VI. Takeaways / Consensus and non-consensus items

Authors: CAISO

Additional discussion in a CAISO stakeholder process is necessary to determine which value(s) CAISO should use for its processes in order to operationalize the CPUC's 24-hour RA framework. The QC values used to develop the NQC list and values used for CAISO showings have different implications for downstream CAISO processes such as setting must offer obligations, outage substitution obligations, and MIC. Although SCE's proposal would result in limited changes to CAISO processes and systems, it could result in discrepancies between peak hour compliance at the CPUC and CAISO system assessments.

SVCE highlighted that QC and showing values based on maximum values from CPUC processes, could effect the amount of MIC that LSEs must secure. MRP also noted that using a maximum value for system peak compliance could result in total shown capacity exceeding demand plus PRM.[105] The CAISO agrees that these outcomes are possible if showings are based on maximum values that may be non-coincident with each other and non-coincident with the peak hour. To address this issue, the CAISO suggested that the CAISO could also use LSE/supplier peak hour showings as the basis for CAISO system RA assessments.[106]

The CAISO compliance options discussed in workshops, and other potential options, should be developed further in CAISO's forthcoming stakeholder process. The CAISO recognizes that open questions remain in terms of how SOD will align with CAISO's RA framework. Parties should continue discussion on this issue in a CAISO stakeholder process to allow for a more thorough vetting of open

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[105] MRP 10/6 presentation, Slide 10.

[106] CAISO 9/21 presentation, Slide 7.

issues and interactions with key CAISO processes. The CAISO also expects that changes to CAISO systems, templates, and processes may be required to operationalize the CPUC's 24-hour RA framework. Before making such changes, the CAISO must ensure that all its LRAs are aware of any proposed changes and have an opportunity to provide their feedback and suggestions.

VII. References

- **CAISO 9/21 presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-21-2022-cpuc-caiso-processes/workshop-8_caiso_220921.pdf
- **SCE 9/22 presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-29-2022-test-year-follow-up-on-remaining-issues/workshop-9_sce_220929.pdf
- **SCE Slice of Day 24 Slice Model:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/ra-reform-excel-workbooks/sce-slice-of-day-24-slice-model-20220921.xlsx
- **SVCE 10/6 presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_svce_221006.pdf
- **MRP 10/6 presentation:** https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/workshop-10_mrp_221006.pdf

iii. Elimination of flexible RA requirements

Authors: PG&E, with support from CAISO, collaboration with ED

I. Background

Authors: PG&E

The development, and implementation, of a 24-hour slice RA framework raises questions regarding the continued need for flexible RA. Flexible RA requirements were instituted to ensure that resources on the grid could respond quickly to steep evening ramps as solar output decreases. These resources are defined by their ability to ramp and sustain energy output for 3 hours.

The benefits presented by the granularity of slice-of-day should adequately account for resource capabilities. To this point, in D.22-08-039 the Commission agreed that these requirements may be unnecessary but stressed that removal would require coordination between the CAISO and the CPUC. Presently, the overall need for flexible capacity is based on the CAISO's Flexible Capacity Needs Assessment. LSE requirements are determined by the CPUC and based on load-ratio. These resources are subject to a Flexible Resource Adequacy Must Offer Obligation (FRACMOO).

To facilitate alignment with the CAISO, the Commission directed parties to develop proposals for the elimination of flexible RA for consideration within these workstreams.

II. Issues

Authors: PG&E

Key issues:

- Should the Flexible RA requirement be removed, and, if so, how should it be done

III. Presenters and Dates

Authors:

- Workshop 8: September 21, 2022:
    - Energy Division

IV. Proposal Summary

Authors: PG&E

Energy Division's proposal represents an evaluation of the current state of flexible RA. In their presentation in the September 21st workshop Energy Division detailed the pros and cons of removing the flexible capacity obligation concurrent with implementation of Slice of Day.

First, Energy Division described a series of arguments in favor of removing the flexible resource adequacy requirement. ED asserts that removal of the requirement will enhance administrative flexibility associated with a highly complex framework. ED's presentation also emphasized the fact that flexible capacity prices have not reflected a system incentivizing new flexible capacity as those prices are not higher than those for system RA and more resources are shown than are required. Finally, ED questioned the sufficiency of RA Availability Incentive Mechanism (RAAIM) penalties to incent desirable bidding behavior and notes that the CAISO's proposed imbalance reserve product may be duplicative of flexible RA requirements.

Finally, ED noted the two primary arguments against removal of the flexible requirement. First, removal of the requirement would remove the must offer obligation and exposure to RAAIM penalties for the 17-hour, 7 day/week period. Moreover, removal of this requirement requires significant alignment between the CPUC and CAISO RA rules. Modifying one set of requirements without adjusting the other in a corresponding manner would likely result in significant confusion. Furthermore, the flexible capacity requirement is part of the CAISO tariff, and ED noted that a CAISO stakeholder process would be required to eliminate it.

V. Questions for parties

Authors: Energy Division Staff

- Would removal of the flexible requirement impact incentives to bid in the real-time market?
- How would removal of the flexible requirement impact RA bid insertion?
- How would removal of the flexible requirement impact RAAIM penalty calculations?

- Do parties support removal of the flexible RA requirement? If so, how should CPUC and CAISO coordinate in doing so?

VI. References

- **Energy Division 9/21 Presentation**: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-21-2022-cpuc-caiso-processes/workshop-8_ed_20220921.pdf

IV. Package Proposals

Authors: MRP

Problem statement/need for an integrated solution

The two sets of workshops conducted to develop implementation details for the 24-hourly Slice-Of-Day (SOD) successor to the current RA program – one set in September through December 2021 and a second set in July through October 2022 – focused on discrete aspects of the successor program, such as resource counting rules, showing and validation tools, and the development of the appropriate Planning Reserve Margin ("PRM"). The workshops did not begin with parties agreeing on the underlying issues that plague the current RA program but rather with parties seeking to develop new methods to implement the Commission's decision.

The catalyst for restructuring the RA program almost certainly was the August 2020 load shedding events. The joint agency final root cause analysis cites these three factors leading to rotating outages: 107

- The climate change-induced extreme heat wave across the western United States resulted in demand for electricity exceeding existing electricity resource adequacy (RA) and planning targets.
- In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand in the early evening hours. This made balancing demand and supply more challenging during the extreme heat wave.
- Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions.

The final factor relates solely to the CAISO's energy markets, and the CAISO has taken steps to address the market practices that contributed to the rotating outages. The first two factors, however, serve as a problem statement for the need to reform the RA program. In sum, California's RA program, which had very successfully maintained reliability and avoided the need for rotating outages from the program's inception in 2004 until 2020, failed to keep pace with increasingly volatile weather (as experienced most recently in 2017, 2020 and 2022) and the resulting high peak electrical demands. The 15% Planning

[107] California ISO, California Public Utilities Commission and California Energy Commission January 13, 2021 *Final Root Cause Analysis Mid-August 2020 Extreme Heat Wave* at pages 3-5, 38-43.

Reserve Margin ("PRM") adopted for the RA program in 2004 was neither validated as the number that would maintain reliability to the RA program's 0.1 Loss-of-Load Expectation (LOLE) target, nor reconsidered in the face of extreme weather or the changing resource mix. Finally, as captured in the second factor, the RA program also failed to keep pace with the implications of the changing resource mix – notably, the growth in grid-connected solar from a few hundred MW in 2004 to nearly 17,000 MW in 2021, and the corresponding growth in behind-the-meter solar from 60 MW in 2004 to over 11,000 MW in 2021. The changing resource mix transformed the most challenging operating time of day from the gross load peak in the afternoon to the net load peak in the evening – the two August 2020 load shedding events began at 6:38 PM and 6:28 PM.

MRP's discussion of the causes of the August 2020 rotating outages is intended to emphasize this point: the need for RA program does not stem from a single cause, but from the combined effects of multiple causes. Merely adopting a more conservative load forecast or reforming the capacity counting rules to account for the time of day, or implementing a new PRM, in isolation and by themselves, will not correct the deficiencies in the current program. Instead, a series of interrelated, coordinated changes must be implemented. As Decision (D.)22-06-050 directed for the 2022 Reform Track Workshops: "Parties should work together to arrive at an optimal final proposal that addresses the Commission's guidance and concerns set forth in this decision."108 An optimal final proposal cannot be developed by simply selecting individual a la carte options from the discrete workshop topic proposals. Instead, the Commission must carefully consider how the interrelated elements work together within a program that first and foremost maintains reliability, but also does so within the framework of the Commission's other simultaneous responsibilities of affordability and decarbonization.

Process Overview

In July 2021, D.21-07-014 directed parties to develop a final restructuring proposal built on PG&E's slice-of-day proposal through a minimum of five workshops to be held over the final half of 2021. Those workshops should cover the following implementation details: (1) Structural Elements; (2) Resource Counting; (3) Need Determination and Allocation; (4) Hedging Component; and (5) Unforced Capacity Evaluation (UCAP) and Multi-Year Requirement Proposals.109 The workshops should also deal with transactability of RA products, multi-day reliability events, and alignment of RA compliance penalties and CAISO backstop procurement.110

When the 2021 workshops began, PG&E's SOD proposal was based on six four-hour slices. In October 2021, SCE proposed that the SOD framework include 24 hourly slices. Following the 2021 workshop process and the Future of RA Working Group report, the Commission concluded that, while the 24-SOD framework best addressed the principles and concern set forth in D.21-07-014, that framework raised "…complexities and outstanding issues that must be further developed…".111 The Commission therefore directed a second series of workstreams and workshops to be held in July to October

[108] D.22-06-050 at page 110.
[109] D.21-07-014 at page 39.
[110] *Id.*
[111] D.22-06-050 at page 76

2022.[112] The Commission encouraged the parties that co-facilities the 2021 workshops to co-facilitate the 2021 workshops.

The 2022 workshop process kicked off on July 27 and concluded on October 6. The co-facilitators set the schedule for the workstream topics and the workshops, and various parties took turns facilitating the workshops. The workshops focused on specific topics and issues within the 24-hour SOD framework. Despite D.22-06-050's goal of parties working together to develop an optimal proposal, such collaboration did not take place within the workshop process.

During the workshops, some parties presented various ideas and concepts while others presented proposals but overall, there was no complete proposal that attempted to link all the components of the new RA framework together. For at least one of the workstream topics – topic 3 (b), Identify and resolve administrative changes to the RA program at both the CAISO and the Commission (e.g., must-offer reporting, outage substitution) – no proposed resolution was presented or even suggested, as the CAISO indicated it was planning to conduct its own stakeholder initiative to "operationalize" the 24-hour SOD framework after the conclusion of the Reform Track workshop process.

While the schedule set forth in D.22-06-050 called for final proposals from Workstreams 1-3 to be submitted on November 15, on September 23 Energy Division issued an e-mail indicating that the workshop report, scheduled to be released on November 15, would include only those proposals that had been presented during a workshop.

In sum, while the workshop process stimulated conversation around discrete topics, it did not produce, or even meaningfully consider, the collaborative optimal final proposal that D.22-06-050 purported to desire.

MRP presents a proposal package below to respond to the Commission's request for an optimal proposal that links together the critical components of the new RA framework so that it can function to improve and maintain reliability while simultaneously meeting affordability and decarbonization goals. MRP's proposal package will include work and ideas from other parties because it is better to give credit rather than replicating work of others that we support. MRP understands that not all parties may agree with or support this proposal, but we understand the tradeoffs and have attempted to describe them within the proposal package. MRP strongly believes that this is simply an initial step towards implementing and testing the new SOD RA framework, and the Commission must continue to adopt modifications to the SOD RA framework in the future. MRP believes this proposal package is holistic and the various components depends on other carefully chosen components to ensure reliability, affordability and decarbonization goals.

MRP Proposal Package

The goal of the RA program is to maintain grid reliability at a level of 1-in-10-year loss of load expectation (LOLE). Energy Division Staff generally run a LOLE study to identify a portfolio of resources that would meet the 1-in-10-year Loss of Load Probability (LOLP) standard under a 1-in-2-year load forecast. This study and its results are highly dependent on the accuracy of two very important inputs and methodology to meet the goal of maintaining 0.1 LOLE.

[112] D.22-06-050 at Ordering Paragraphs 27 and 28.

Inputs:

Resources: Because the results of the LOLE study are targeted to maintain reliability in the near term, rather than for a time far out in the future, the resource fleet used for the study must reflect the expected resources for that near term. This means that the resource fleet would consist of all existing resources and any new resources that are expected to come online by that year. This would provide a better representation of the subset of resources that will be needed to meet the reliability standard in the near term. If that fleet of resources is unable to meet the reliability standard, then additional resource capacity would need to be added. Energy Division staff originally stated that they would add additional perfect capacity, but at the final workshop, they revised the proposed method to add additional import capacity on a monthly basis in order to achieve the 0.1 LOLE reliability standard.

Imports: Energy Division stated that they would use 4,000 MWs of imports, primarily during summer months for the LOLE study.

Proposal: MRP believes that the LOLE study should use existing resources and resources expected to be online by the compliance year as the basis of the supply mix. If additional resources are necessary, then Energy Division staff should insert additional import capacity, limited to the maximum import capability ("MIC") of the CAISO grid, net of import capability utilized by dynamically transferred resources, for the study to meet the 0.1 LOLE reliability standard. MRP proposes that the LOLE study should use the 3-year historic average of monthly shown RA imports for non-resource specific imports rather than the generic 4,000 MWs proposed by Energy Division. This offers a more realistic import assumption that is based on actual LSE shown imports.

Load Forecast: The other component of the inputs is the load forecast. Energy Division uses the Strategic Energy and Risk Valuation Model ("SERVM") and the SERVM load forecast to determine the reliability portfolio. The SERVM load forecast is "calibrated" to the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) 1-in-2 high electric vehicle (EV) load forecast. The resulting reliability portfolio is compared to the CEC IEPR load forecast calculate the expected planning reserve margin based on the capacity values assigned to the reliability portfolio. Further discussion of the LOLE study outputs will be included in the PRM section of the proposal.

Proposal: MRP believes using Energy Division's SERVM model and load forecast is reasonable for the near future for when the SOD framework will be implemented. However, given increased climate change impacts on load and supply, and the Governor's establishment of the strategic reliability reserve to cover extreme weather and wildfire risks beyond that of the traditional planning standards, MRP believes that the Commission should consider whether the SERVM load forecasts should be based on 1-in-1-0 year load forecasts rather than the 1-in-2-year load forecasts. MRP acknowledges that there is insufficient record developed to make this change and therefore does not propose such a change. But rather, MRP raises this concern to highlight concerns if the RA program does not reasonably plan for such events.

Outputs:

The LOLE study will provide a reliable portfolio of resources necessary to meet the 1-in-10-year LOLE standard. The capacity value of this portfolio is compared to the peak load of the CEC's IEPR 1-in-2- year load forecast to calculate the PRM. This portfolio will be an annual portfolio, which means that it assumes the resources will be "shown" for the entire year. This is different than the current RA program, in which LSEs contract and show resources to meet their varying monthly requirements. Because of the monthly RA construct, additional steps must be taken within the LOLE study to maintain 0.1 LOLE with a single annual PRM. Additional discussion regarding these steps is available below in the PRM section.

Planning Reserve Margin

The current RA framework utilizes a single annual PRM for all months of the compliance year. The current 2023 PRM is 16% and the 2024 PRM is a minimum of 17% pending additional LOLE analysis from Energy Division for Commission consideration.[113] The PRM is a function of the capacity values assigned to the reliability portfolio necessary to meet a load metric, e.g., gross peak load or net load peak, and the load metric chosen. Therefore, higher capacity values of the given portfolio will yield a higher PRM when compared to lower capacity values of the same portfolio, to meet the same load metric. However, since the capacity values of the reliability portfolio vary monthly, as do the gross peak loads, the monthly PRM would also vary and would not be the same as one used to meet the annual gross peak load. Said differently, the annual PRM determined from looking at the peak demand for the month of September may not be applicable for other months of the year because of the different relationships between the monthly capacity values and monthly gross peak loads of other months within the RA program.

During workshop 10, Energy Division showed that, if the September PRM were used for all months, then the LOLE increased to 0.4 or 1-in-2.5 years. In order to establish an annual PRM, additional steps would be required. Energy Division showed that, to maintain 0.1 LOLE with an annualized PRM, a single PRM that is applied to all months would need to be ~23% or an increase of 3% from the September PRM.[114]

<u>Methodology</u>: It is necessary to tune or calibrate the LOLE study such that the reliability portfolio mimics that of the monthly RA framework, instead of just assuming that all resources are available all twelve months of the year. To do this, the LOLE study should reduce the RA portfolio on a monthly basis to meet the annual PRM. During workshops, MRP proposed that capacity should be reduced in the following order:

1. Any additional perfect capacity that may have been added by Energy Division in that month in order to achieve annualized 0.1 LOLE.
2. Monthly Imports
3. Thermal resources

The result of this reduction would yield a portfolio with more preferred and energy storage resources. Such a portfolio conservatively would represent the most challenging portfolio with which to maintain 0.1 LOLE; if such a portfolio achieved 0.1 LOLE, then the addition of any other type of capacity would be expected to maintain no worse than a 0.1 LOLE. Energy Division Staff should run these monthly reliability portfolios in SERVM to assess whether 0.1 LOLE can be maintained across the year.

[113] D.22-06-050 at page 22, Ordering Paragraphs 16 and 17.
[114] Energy Division October 6, 2022 Presentation (for Workshop 10) at Slide 12.

If these monthly portfolios are able to maintain 0.1 LOLE across the year, then these portfolios can be transferred to the PRM conversion tool, discussed later in this proposal. However, if the monthly portfolios are not capable of maintaining a 0.1 LOLE, then additional capacity, previously removed, must be added back to meet a higher annual PRM. MRP suggests that PRM calibration should increase in 1% increments to reduce the number of iterations of this calibration.

Energy Division has presented an alternative method for this calibration. Instead of removing capacity from the portfolio, Energy Division Staff increased the monthly load forecast so that the resulting PRM can be the same for every month in order to maintain 0.1 LOLE. As described above, under Energy Division's recent analysis, applying the initial September PRM (~20%) to all months resulted in a 0.4 LOLE as loss of load events surfaced in other months. In turn, Energy Division increased the PRM as well as additional imports to achieve the 0.1 LOLE reliability metric for the entire year. MRP has two concerns with this approach. First, it seems that Energy Division increased the level of imports in September to nearly 10,000 MWs, which is quite close to the CAISO's total MIC. The CAISO's MIC also includes all dynamically transferred resources which means less MIC is available for other non-resource specific imports to be counted as RA capacity. MRP understands that this limitation may make the LOLE study infeasible to ensure 0.1 LOLE with a single PRM value for all months of the year. However, this is only a transitional issue until additional new resources from the mid-term reliability procurement order comes online. If infeasible, then it is likely that seasonal PRMs may be required to ensure 0.1 LOLE in the interim. Energy Division's LOLE study suggests that it's possible to set the September PRM to ~20% while the other months of the year are set to ~30%.

Second, while adding load is a simpler method, the resulting portfolio still assumes all resources are contracted or shown for the entire year. This may create an issue during the PRM conversion process for the Slice of Day (SOD) framework. The PRM conversion tool will require either the monthly portfolios with the original CEC IEPR load forecast or the annual portfolio with the adjusted load forecast. These components cannot be mixed as it would result in a much different PRM for SOD and it would not be comparable to the PRM obtained from the LOLE study results. Ensuring that the correct PRM for the current RA framework is chosen will impact the 2024 SOD test year because LSEs will be procuring capacity to meet monthly peak loads and current framework PRM. If a different PRM is chosen that does not maintain reliability and the SOD PRM is converted from the reliability portfolio, then LSEs may not be able to meet their SOD RA obligations because the two frameworks are no longer comparable. While much of the above applies to the 2024 LOLE study and resulting PRM, which is slated for Phase 3 of the RA proceeding, it is necessary to understand these points here because the SOD RA conversion depends on the portfolio of the LOLE study under the current RA framework.

Finally, the Commission should understand that if it adopts methodologies or inputs that differ from that which was used by Energy Division in its LOLE analysis, then Energy Division should re-run its analysis to make the analyses consistent. It's unclear if substantive differences would result because Energy Division has not provided its final results at the time of this writing. To the extent that the Commission adopts a proposal that is different than used in Energy Division's methodology and inputs, MRP proposes that the Commission order Energy Division staff to update its analysis prior to the conversion of the SOD PRM.

<u>Conversion Methodology</u>:

When the Commission adopted the SOD framework, it understood that the SOD PRM would not be the same as one used in the existing RA framework because the existing RA framework requires LSEs to procure sufficient resources to meet gross peak demand + PRM with maximum cumulative capacity (MCC) constraints to cover all hours across the entire month. This is accomplished through a stack analysis by summing up all the capacity to meet the RA requirement. Under the SOD framework, LSEs are required to procure sufficient resources for each hourly forecast + PRM and therefore capacity cannot be "stacked" to meet a single requirement, but instead must meet 24 requirements per month. The 24-SOD PRM is likely to be lower, compared to the current PRM, because of the lack of stacking of capacity. However, both PRMs rely on the LOLE reliability portfolio to ensure a 0.1 LOLE.

In order to calculate the SOD PRM, the Commission ordered parties to begin with the Natural Resources Defense Council's (NRDC's) PRM conversion tool. During workshops, Southern California Edison (SCE) provided its own conversion tool as an iterative step of the PRM conversion. Energy Division used the NRDC tool to present some draft results of the LOLE analysis as well. However, usage of both tools was not fully discussed during workshops as the LOLE reliability portfolio is not available. SCE provided an example of its tool using the 2030 IRP portfolio.

MRP believes that SCE's conversion tool, developed in conjunction with other necessary templates for LSEs to ensure compliance, works well. The SCE tool, along with one developed by NRDC, requires both the LOLE reliability portfolio to be developed as well as new QC methodologies to be adopted for the SOD framework before it can be fully utilized. MRP suggests that once this information is finalized by Commission decision, a workshop should be scheduled to review the conversion by Energy Division staff. Parties should be provided with the opportunity to comment on the work product and the Commission should set out a schedule to issue a proposed decision of the work product prior to August 2023 so that LSEs may be prepared for the 2024 test year.

Qualifying Capacity Methodologies

<u>Wind/Solar Exceedance Methodologies:</u>

The Commission adopted an hourly exceedance methodology for variable energy resources because the 24-SOD framework requires 24 different capacity values for each resource.115 Each slice would recognize the generation capability of the resource technology based on historical output in that hour. This is different than the traditional expected load carrying capability (ELCC) of a resource that measures the reliability contribution across each month or year.

The SOD framework was adopted to ensure that LSEs can demonstrate that they have enough capacity to satisfy their gross load profiles for the worst day. The "worst day" is defined as the day of the month that contains the hour with the highest coincident peak load forecast. The Commission requested PG&E's exceedance methodology to be further developed during workshops.116 PG&E benchmarked its exceedance methodology for wind and solar resources to average production during stressed system conditions.117 During workshops and within this working group report, PG&E proposes that "stressed

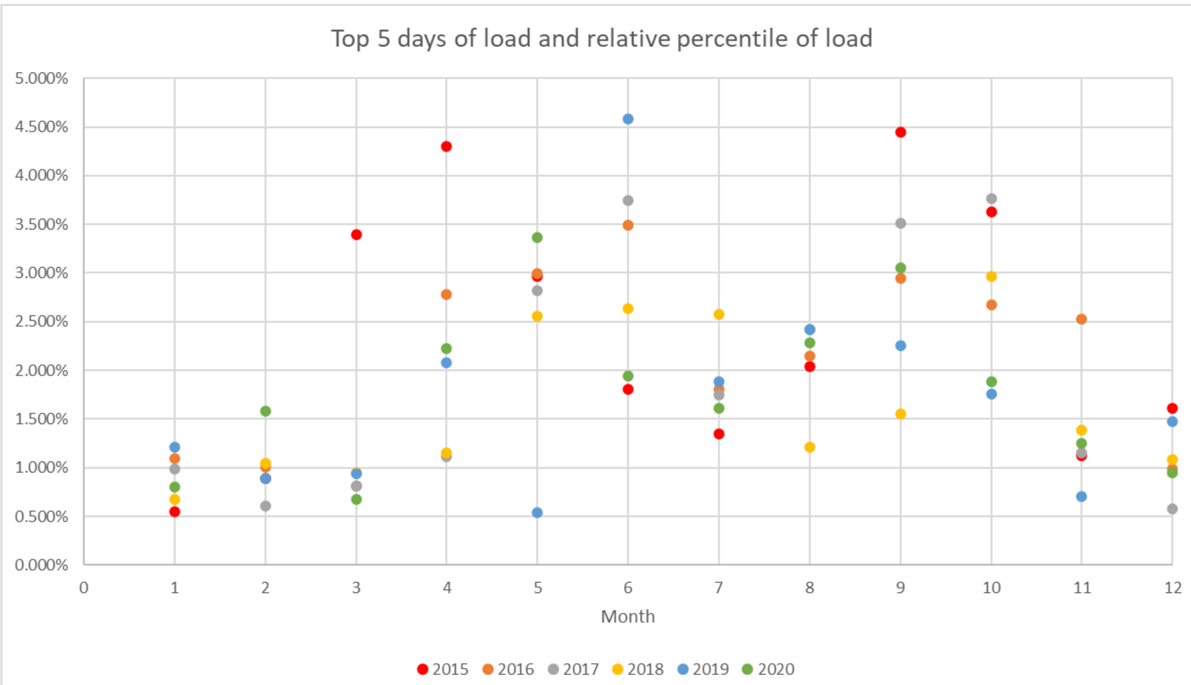
[115] D.22-06-050 at pages 80-81, Ordering Paragraph 17..
[116]*Id.*
[117] See, e.g., PG&E August 23, 202 Presentation (for Workshop 5) at Slide 3.

system condition" days is the Top 5 Peak load days of each month. With data provided from 2015-2020, that provides 30 data points for each hour for the exceedance methodology benchmarking.

The critical question here is whether the Top 5 Peak days of each month fully represent expected resource output during stressed system condition?

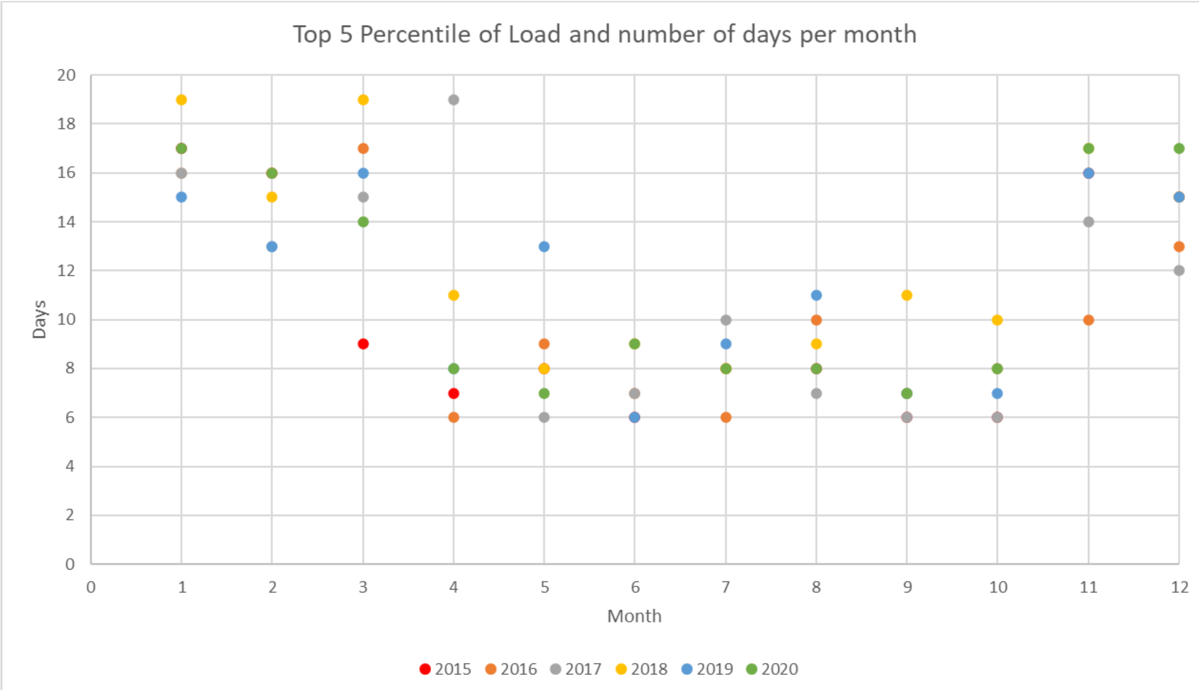
MRP reviewed PG&E's data and noticed that the Top Five Peak days represented different top percentiles of peak load hours for each month. As can be seen below, the Top Five Peak days results in a cutoff between 0.54% to 4.6% of "peak load hours" in each month. While MRP recognizes that each hour will have 30 data points (2015-2020) for the benchmarking, it is nevertheless surprising to see how high of a percentile this cut off was as the average was less than 1.93% of total hours.

Figure 61: Top 5 Days of Load and Relative Percentile of Load



MRP was concerned that deriving resource capacity values from such a limited data set would have two weaknesses. First, the Top 5 Peak days may not be representative of all the stressed days experienced in a month. Second, due to the limited number of days, the generation data for the benchmarking is also too small of a sample size. In turn, MRP focused on the days that have peak loads that fall within the top five percent (Top 5%) of hours in each month. If a day had an hour of load above the cutoff threshold, then all hours of the day's generation data would be included as part of the benchmarking exercise.

Figure 62: Top 5 Percentile of Load and Number of Days per Month



This yielded a range of six (6) to 19 days and an average of 11 days in each month. MRP believes this is a more robust dataset with which to benchmark the generation data to identify the exceedance thresholds for determining VER RA capacity values. MRP also considered top 2.5% as well as the top 10% of hours as cutoff thresholds but found that either too few or too many days were included in the dataset for benchmarking. This is due to the fact that generally in non-summer months, the peak load values are fairly similar and therefore the top 10% of load hours may include all days of the month instead of only high stress days. MRP believes this tradeoff between a robust set of data vs too few days which may not provide sufficient data for benchmarking purposes.

Based on the average of the Top 5% benchmark, MRP used PG&E's methodology to calculate the exceedance thresholds for solar and wind resources. MRP attempted to minimize the hourly differences between the exceedance values and that of the average benchmark. Calculating exceedance values uses all hours and days of each month. This offers more data for the calculation. However, the resulting values may differ significantly from the benchmark for a particular hour. The immediate question to ask is why not simply use the benchmark itself as the capacity value? It's important to understand that the benchmarks only incorporate subsets of days in a month whereas the exceedance calculations incorporate all days in month. As previously explained, this introduces more variability of data and allows for greater confidence of expected generation profiles that can meet multiple types of weather and load events. This is a tradeoff. As discussed later, benchmarking the exceedance threshold only minimizes the delta between the hourly profile and the benchmark for a certain set of hours. This step sacrifices using a robust sample set that captures a wider range of events for reduced administrative complexity.

MRP's proposed exceedance thresholds uses two seasons. Summer months are May through October, while non-summer months are November through April. This is also aligned with the year-ahead showing months.

Solar Resources

For solar resources, MRP proposes an 80% exceedance threshold for summer months and 60% exceedance threshold for non-summer months. The hourly exceedance profiles by month are in the figure below.

Table 19: MRP Proposed Solar Exceedance Profile

Solar Exceedance Profile

Exceedance %		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
60%	1 Jan	0%	0%	0%	0%	0%	0%	0%	7%	29%	43%	50%	53%	53%	51%	43%	28%	6%	0%	0%	0%	0%	0%	0%	0%
60%	2 Feb	0%	0%	0%	0%	0%	0%	0%	17%	48%	62%	66%	67%	68%	66%	60%	51%	22%	1%	0%	0%	0%	0%	0%	0%
60%	3 Mar	0%	0%	0%	0%	0%	0%	0%	9%	40%	62%	69%	69%	70%	68%	65%	60%	44%	21%	4%	0%	0%	0%	0%	0%
60%	4 Apr	0%	0%	0%	0%	0%	0%	1%	22%	53%	69%	76%	78%	79%	78%	77%	71%	64%	48%	16%	1%	0%	0%	0%	0%
80%	5 May	0%	0%	0%	0%	0%	0%	6%	31%	53%	64%	72%	74%	74%	73%	72%	68%	60%	45%	21%	2%	0%	0%	0%	0%
80%	6 Jun	0%	0%	0%	0%	0%	0%	9%	36%	58%	71%	78%	81%	81%	79%	78%	74%	66%	52%	29%	6%	0%	0%	0%	0%
80%	7 Jul	0%	0%	0%	0%	0%	0%	5%	28%	54%	68%	76%	80%	81%	79%	77%	73%	65%	52%	29%	6%	0%	0%	0%	0%
80%	8 Aug	0%	0%	0%	0%	0%	0%	1%	19%	48%	65%	73%	77%	78%	76%	74%	69%	59%	44%	16%	1%	0%	0%	0%	0%
80%	9 Sep	0%	0%	0%	0%	0%	0%	0%	13%	43%	60%	68%	72%	73%	72%	69%	63%	51%	27%	4%	0%	0%	0%	0%	0%
80%	10 Oct	0%	0%	0%	0%	0%	0%	0%	6%	32%	54%	63%	65%	65%	65%	64%	58%	39%	10%	0%	0%	0%	0%	0%	0%
60%	11 Nov	0%	0%	0%	0%	0%	0%	1%	19%	46%	59%	62%	62%	61%	59%	52%	29%	3%	0%	0%	0%	0%	0%	0%	0%
60%	12 Dec	0%	0%	0%	0%	0%	0%	0%	8%	29%	44%	48%	49%	50%	48%	41%	21%	2%	0%	0%	0%	0%	0%	0%	0%

The average benchmark of the top 5% days is in the figure below.

Table 20: Average Solar Generation on Top 5% Days (2015-2020)

Average Solar Generation on Top 5% Days (2015-2020)

Hour Ending

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1 **Jan**	0%	0%	0%	0%	0%	0%	0%	7%	30%	45%	52%	54%	53%	52%	46%	31%	8%	0%	0%	0%	0%	0%	0%	0%
2 **Feb**	0%	0%	0%	0%	0%	0%	1%	18%	49%	64%	69%	70%	69%	68%	63%	52%	24%	2%	0%	0%	0%	0%	0%	0%
3 **Mar**	0%	0%	0%	0%	0%	0%	1%	16%	44%	62%	71%	73%	73%	72%	68%	62%	48%	25%	6%	0%	0%	0%	0%	0%
4 **Apr**	0%	0%	0%	0%	0%	0%	3%	29%	61%	76%	84%	86%	87%	87%	85%	80%	71%	52%	20%	1%	0%	0%	0%	0%
5 **May**	0%	0%	0%	0%	0%	0%	9%	40%	66%	79%	86%	87%	89%	88%	87%	82%	73%	57%	28%	4%	0%	0%	0%	0%
6 **Jun**	0%	0%	0%	0%	0%	0%	12%	43%	66%	78%	84%	87%	86%	85%	85%	80%	73%	60%	36%	8%	0%	0%	0%	0%
7 **Jul**	0%	0%	0%	0%	0%	0%	6%	32%	57%	70%	78%	81%	82%	79%	78%	73%	65%	53%	30%	6%	0%	0%	0%	0%
8 **Aug**	0%	0%	0%	0%	0%	0%	2%	24%	53%	69%	74%	81%	81%	80%	77%	71%	63%	47%	20%	2%	0%	0%	0%	0%
9 **Sep**	0%	0%	0%	0%	0%	0%	1%	18%	50%	68%	76%	79%	79%	78%	75%	69%	58%	36%	8%	0%	0%	0%	0%	0%
10 **Oct**	0%	0%	0%	0%	0%	0%	0%	9%	41%	64%	71%	74%	74%	74%	72%	67%	50%	17%	1%	0%	0%	0%	0%	0%
11 **Nov**	0%	0%	0%	0%	0%	0%	2%	22%	48%	59%	61%	62%	61%	60%	51%	30%	5%	0%	0%	0%	0%	0%	0%	0%
12 **Dec**	0%	0%	0%	0%	0%	0%	0%	9%	32%	45%	49%	50%	50%	48%	41%	22%	2%	0%	0%	0%	0%	0%	0%	0%

The figure below shows the difference between the hourly exceedance profile and the hour ending profile. The green shaded area indicates where the exceedance profile value is lower than the average benchmark of the Top 5% profile whereas the red shaded area indicates where the exceedance profiles is greater than the average benchmark. The goal is to minimize both the green and red shades so that the difference of the hourly values is 0% so as to not over-count a resource's generation ability during stressed hours of grid need. This is a conservative approach to ensure reliability. This is difficult to accomplish with a single exceedance threshold across multiple months and all hours of the day due to the variable nature of these resources. MRP attempted to target the differences in the figure below to 0% during critical hours, primarily HE 16 through HE 21. However, the month of July was the most limiting for the summer months as it resulted in the least amount of deviation for the summer months. This is a tradeoff that sets July hourly profiles close to the July Top 5% benchmark but deviates from the same benchmark in other summer months. As the figure below shows, if as the exceedance value decreased to 60%, July's hourly profiles became greater than the average benchmark on many more hours.

Figure 63: Change from 80% to 60% Exceedance

Exceedance	Average Top 5% Days vs Exceedance																							
80%	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
1 **Jan**	0%	0%	0%	0%	0%	0%	0%	-3%	-11%	-13%	-10%	-8%	-10%	-12%	-15%	-13%	-4%	0%	0%	0%	0%	0%	0%	0%
2 **Feb**	0%	0%	0%	0%	0%	0%	-1%	-5%	-11%	-14%	-12%	-13%	-14%	-15%	-14%	-13%	-8%	-1%	0%	0%	0%	0%	0%	0%
3 **Mar**	0%	0%	0%	0%	0%	0%	-1%	-10%	-11%	-10%	-13%	-14%	-13%	-14%	-14%	-16%	-19%	-19%	-6%	0%	0%	0%	0%	0%
4 **Apr**	0%	0%	0%	0%	0%	0%	-3%	-12%	-15%	-15%	-18%	-18%	-17%	-19%	-21%	-19%	-18%	-15%	-7%	-1%	0%	0%	0%	0%
5 **May**	0%	0%	0%	0%	0%	0%	-3%	-9%	-14%	-15%	-14%	-13%	-15%	-16%	-14%	-14%	-14%	-12%	-7%	-2%	0%	0%	0%	0%
6 **Jun**	0%	0%	0%	0%	0%	0%	-2%	-7%	-8%	-7%	-6%	-6%	-5%	-6%	-7%	-7%	-7%	-8%	-6%	-2%	0%	0%	0%	0%
7 **Jul**	0%	0%	0%	0%	0%	0%	-2%	-4%	-3%	-3%	-2%	-1%	-1%	1%	-1%	0%	0%	-1%	-1%	-1%	0%	0%	0%	0%
8 **Aug**	0%	0%	0%	0%	0%	0%	-1%	-5%	-5%	-4%	0%	-3%	-3%	-3%	-3%	-2%	-4%	-3%	-5%	-1%	0%	0%	0%	0%
9 **Sep**	0%	0%	0%	0%	0%	0%	0%	-5%	-7%	-8%	-7%	-7%	-6%	-6%	-6%	-6%	-7%	-9%	-4%	0%	0%	0%	0%	0%
10 **Oct**	0%	0%	0%	0%	0%	0%	0%	-4%	-9%	-9%	-8%	-9%	-9%	-8%	-8%	-9%	-11%	-7%	-1%	0%	0%	0%	0%	0%
11 **Nov**	0%	0%	0%	0%	0%	0%	-1%	-7%	-10%	-9%	-7%	-6%	-8%	-8%	-9%	-7%	-3%	0%	0%	0%	0%	0%	0%	0%
12 **Dec**	0%	0%	0%	0%	0%	0%	0%	-3%	-10%	-11%	-10%	-9%	-8%	-8%	-10%	-7%	-1%	0%	0%	0%	0%	0%	0%	0%

Exceedance	Average Top 5% Days vs Exceedance																							
60%	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1 Jan	0%	0%	0%	0%	0%	0%	0%	0%	-2%	-2%	-2%	-1%	-1%	-1%	-3%	-3%	-2%	0%	0%	0%	0%	0%	0%	0%
2 Feb	0%	0%	0%	0%	0%	0%	0%	-2%	-1%	-2%	-2%	-3%	-2%	-2%	-4%	-1%	-2%	-1%	0%	0%	0%	0%	0%	0%
3 Mar	0%	0%	0%	0%	0%	0%	-1%	-7%	-4%	-1%	-2%	-4%	-3%	-4%	-3%	-2%	-4%	-5%	-1%	0%	0%	0%	0%	0%
4 Apr	0%	0%	0%	0%	0%	0%	-2%	-7%	-8%	-7%	-8%	-8%	-8%	-8%	-8%	-9%	-7%	-5%	-4%	-1%	0%	0%	0%	0%
5 May	0%	0%	0%	0%	0%	0%	-1%	-2%	-4%	-5%	-4%	-3%	-6%	-6%	-6%	-5%	-4%	-3%	-1%	-1%	0%	0%	0%	0%
6 Jun	0%	0%	0%	0%	0%	0%	0%	-2%	0%	-1%	-1%	0%	2%	2%	0%	0%	1%	1%	0%	-1%	0%	0%	0%	0%
7 Jul	0%	0%	0%	0%	0%	0%	0%	0%	2%	2%	2%	3%	3%	5%	4%	5%	6%	5%	4%	1%	0%	0%	0%	0%
8 Aug	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	5%	2%	3%	3%	5%	5%	4%	2%	0%	-1%	0%	0%	0%	0%
9 Sep	0%	0%	0%	0%	0%	0%	0%	-2%	-2%	0%	0%	0%	0%	0%	2%	3%	3%	-3%	-3%	0%	0%	0%	0%	0%
10 Oct	0%	0%	0%	0%	0%	0%	0%	-2%	-3%	-4%	-3%	-2%	-2%	-2%	-2%	-2%	-3%	-4%	0%	0%	0%	0%	0%	0%
11 Nov	0%	0%	0%	0%	0%	0%	-1%	-3%	-2%	0%	1%	0%	-1%	0%	0%	-1%	-2%	0%	0%	0%	0%	0%	0%	0%
12 Dec	0%	0%	0%	0%	0%	0%	0%	-1%	-2%	-1%	-1%	-1%	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%	0%

As a reference point, below is a similar table with 70% exceedance threshold. MRP would not suggest using this exceedance threshold, given how the results compare to the Top 5% benchmark. A monthly exceedance could be developed to minimize the differences between the Top 5% benchmark and the exceedance profiles, MRP however, did not make those calculations.

Figure 64: 70% Exceedance Results

Exceedance 70%	Average Top 5% Days vs Exceedance																							
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
1 **Jan**	0%	0%	0%	0%	0%	0%	0%	-1%	-6%	-6%	-6%	-4%	-5%	-7%	-7%	-8%	-3%	0%	0%	0%	0%	0%	0%	0%
2 **Feb**	0%	0%	0%	0%	0%	0%	-1%	-3%	-5%	-6%	-8%	-8%	-7%	-9%	-9%	-6%	-5%	-1%	0%	0%	0%	0%	0%	0%
3 **Mar**	0%	0%	0%	0%	0%	0%	-1%	-8%	-7%	-6%	-6%	-8%	-8%	-9%	-10%	-10%	-9%	-16%	-4%	0%	0%	0%	0%	0%
4 **Apr**	0%	0%	0%	0%	0%	0%	-2%	-9%	-11%	-12%	-12%	-12%	-13%	-13%	-13%	-14%	-11%	-9%	-6%	-1%	0%	0%	0%	0%
5 **May**	0%	0%	0%	0%	0%	0%	-2%	-6%	-8%	-10%	-9%	-8%	-11%	-9%	-10%	-9%	-9%	-6%	-3%	-1%	0%	0%	0%	0%
6 **Jun**	0%	0%	0%	0%	0%	0%	-2%	-4%	-4%	-4%	-3%	-2%	-1%	-1%	-2%	-3%	-3%	-3%	-3%	-1%	0%	0%	0%	0%
7 **Jul**	0%	0%	0%	0%	0%	0%	-1%	-1%	0%	0%	1%	1%	1%	3%	1%	3%	3%	3%	1%	0%	0%	0%	0%	0%
8 **Aug**	0%	0%	0%	0%	0%	0%	-1%	-2%	-2%	-1%	3%	0%	0%	1%	1%	2%	1%	0%	-3%	-1%	0%	0%	0%	0%
9 **Sep**	0%	0%	0%	0%	0%	0%	0%	-3%	-4%	-4%	-3%	-3%	-3%	-2%	-1%	0%	-2%	-4%	-4%	0%	0%	0%	0%	0%
10 **Oct**	0%	0%	0%	0%	0%	0%	0%	-3%	-6%	-7%	-6%	-5%	-4%	-4%	-4%	-5%	-5%	-5%	-1%	0%	0%	0%	0%	0%
11 **Nov**	0%	0%	0%	0%	0%	0%	-1%	-4%	-6%	-4%	-3%	-3%	-4%	-4%	-4%	-4%	-2%	0%	0%	0%	0%	0%	0%	0%
12 **Dec**	0%	0%	0%	0%	0%	0%	0%	-2%	-5%	-5%	-4%	-4%	-3%	-5%	-5%	-4%	0%	0%	0%	0%	0%	0%	0%	0%

Wind

Wind resources were divided into North Path-15 (NP-15) and South Path-15 (SP-15). MRP proposes the following exceedance thresholds:

Table 21: Exceedance Levels for Wind

	NP-15	SP-15
Summer	75%	75%
Non-Summer	50%	62%

The resulting profiles are in the figures below.

Table 22: NP-15 Wind Exceedance Profile

NP-15 Wind		NP-15 Wind Exceedance Profile																							
		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
50%	1 **Jan**	6%	5%	4%	4%	4%	4%	4%	4%	4%	4%	3%	4%	4%	3%	3%	3%	3%	3%	4%	5%	5%	5%	6%	6%
50%	2 **Feb**	13%	13%	12%	10%	10%	9%	10%	11%	9%	8%	9%	8%	8%	8%	9%	9%	8%	8%	9%	10%	10%	11%	12%	13%
50%	3 **Mar**	16%	14%	14%	13%	11%	10%	8%	8%	8%	7%	7%	7%	6%	7%	7%	8%	10%	10%	12%	14%	17%	15%	16%	17%
50%	4 **Apr**	36%	34%	34%	30%	29%	25%	23%	18%	15%	16%	14%	13%	11%	12%	15%	21%	25%	27%	29%	31%	35%	35%	36%	40%
75%	5 **May**	37%	37%	36%	32%	28%	24%	22%	17%	13%	12%	9%	8%	7%	8%	11%	17%	23%	28%	33%	32%	37%	38%	40%	38%
75%	6 **Jun**	46%	48%	45%	40%	40%	36%	32%	23%	17%	13%	9%	6%	5%	7%	8%	15%	22%	34%	41%	39%	42%	44%	43%	46%
75%	7 **Jul**	62%	61%	57%	53%	50%	46%	43%	36%	30%	21%	15%	12%	10%	12%	16%	25%	35%	43%	47%	49%	56%	57%	61%	62%
75%	8 **Aug**	57%	58%	53%	47%	45%	43%	37%	30%	22%	18%	12%	8%	8%	8%	10%	18%	26%	32%	40%	47%	54%	57%	58%	57%
75%	9 **Sep**	23%	24%	22%	19%	17%	13%	11%	8%	6%	5%	3%	2%	2%	2%	2%	3%	6%	10%	13%	17%	20%	19%	21%	21%
75%	10 **Oct**	9%	9%	7%	5%	4%	4%	3%	3%	3%	2%	1%	1%	1%	1%	1%	1%	1%	1%	3%	4%	5%	6%	7%	9%
50%	11 **Nov**	8%	6%	6%	6%	5%	5%	4%	5%	3%	3%	2%	2%	2%	2%	2%	2%	2%	3%	3%	4%	4%	5%	7%	7%
50%	12 **Dec**	7%	7%	7%	7%	6%	6%	6%	6%	6%	5%	5%	5%	4%	4%	4%	4%	4%	5%	6%	7%	8%	8%	8%	8%

Table 23: SP-15 Wind Exceedance Profile

SP-15 Wind Exceedance Profile

Exceedance %		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
62%	1 Jan	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
62%	2 Feb	7%	6%	6%	6%	5%	5%	5%	5%	4%	4%	4%	5%	5%	6%	7%	8%	9%	9%	8%	8%	8%	7%	8%	8%
62%	3 Mar	15%	15%	14%	13%	14%	11%	10%	9%	7%	7%	7%	9%	10%	10%	12%	14%	16%	17%	19%	19%	17%	17%	17%	14%
62%	4 Apr	29%	30%	28%	26%	24%	20%	19%	15%	12%	12%	13%	12%	12%	14%	18%	23%	27%	30%	33%	32%	31%	31%	30%	30%
75%	5 May	28%	28%	26%	25%	21%	17%	14%	10%	7%	7%	6%	6%	6%	7%	9%	16%	23%	28%	30%	30%	31%	32%	31%	29%
75%	6 Jun	34%	33%	29%	27%	24%	21%	16%	12%	8%	6%	5%	5%	7%	7%	10%	16%	22%	26%	31%	34%	35%	35%	35%	35%
75%	7 Jul	28%	26%	25%	21%	18%	15%	12%	8%	5%	3%	3%	4%	5%	6%	9%	13%	19%	23%	27%	28%	30%	31%	30%	29%
75%	8 Aug	25%	24%	21%	18%	15%	12%	9%	7%	4%	3%	2%	3%	4%	5%	7%	11%	15%	20%	23%	26%	28%	30%	27%	27%
75%	9 Sep	10%	8%	6%	5%	5%	4%	4%	3%	2%	2%	2%	3%	4%	5%	5%	5%	6%	9%	12%	13%	12%	11%	11%	10%
75%	10 Oct	5%	4%	4%	4%	4%	3%	3%	3%	2%	2%	2%	3%	3%	3%	3%	3%	4%	4%	5%	5%	5%	4%	5%	5%
62%	11 Nov	3%	4%	4%	4%	4%	3%	3%	3%	3%	3%	3%	4%	4%	4%	3%	4%	3%	4%	4%	5%	5%	4%	4%	4%
62%	12 Dec	5%	5%	5%	5%	5%	4%	4%	4%	4%	4%	4%	4%	4%	5%	5%	4%	5%	5%	6%	6%	6%	5%	5%	5%

The differences between the generation profiles are shown in the figure below. For NP-15 wind resources, the month with the smallest deviations from the Top 5% benchmark and exceedance profile during grid stressed hours for summer months is August; while the month with the smallest deviations for non-summer months is April.

Figure 65: Difference Between Generation Profiles – NP15

Average Generation on Top 5% Days in NP15 Resources (2015-2020)

NP15 — **Hour Ending**

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1 **Jan**	13%	13%	12%	11%	11%	11%	11%	11%	10%	9%	8%	8%	8%	8%	9%	9%	9%	10%	11%	12%	11%	10%	11%	11%
2 **Feb**	21%	21%	20%	20%	19%	18%	20%	20%	20%	20%	20%	19%	19%	18%	18%	17%	13%	14%	15%	16%	17%	17%	18%	18%
3 **Mar**	17%	17%	17%	17%	18%	16%	15%	16%	15%	14%	15%	15%	15%	17%	18%	18%	20%	19%	20%	21%	22%	22%	22%	21%
4 **Apr**	40%	39%	38%	35%	34%	31%	29%	26%	23%	21%	20%	19%	18%	18%	21%	23%	26%	29%	30%	33%	36%	39%	41%	44%
5 **May**	57%	55%	55%	52%	47%	43%	39%	34%	31%	30%	27%	24%	23%	25%	28%	33%	38%	42%	43%	48%	54%	56%	58%	60%
6 **Jun**	63%	62%	60%	56%	54%	50%	46%	40%	33%	27%	23%	18%	17%	18%	21%	29%	38%	45%	49%	53%	57%	59%	61%	64%
7 **Jul**	68%	67%	65%	62%	60%	56%	54%	48%	40%	33%	26%	22%	22%	22%	29%	36%	44%	50%	52%	56%	61%	64%	67%	68%
8 **Aug**	60%	59%	56%	54%	52%	48%	43%	38%	31%	26%	21%	18%	17%	18%	22%	27%	34%	38%	42%	47%	55%	59%	60%	60%
9 **Sep**	43%	43%	41%	38%	35%	33%	30%	27%	23%	18%	15%	12%	10%	11%	13%	17%	21%	25%	30%	37%	43%	46%	48%	49%
10 **Oct**	19%	19%	19%	16%	15%	13%	12%	11%	10%	9%	10%	10%	9%	10%	10%	10%	10%	11%	13%	16%	20%	22%	24%	25%
11 **Nov**	14%	13%	12%	11%	11%	10%	9%	10%	10%	10%	10%	10%	11%	10%	10%	10%	10%	10%	11%	10%	11%	13%	14%	15%
12 **Dec**	16%	16%	16%	15%	14%	15%	16%	15%	14%	13%	14%	13%	13%	13%	12%	11%	10%	10%	11%	12%	13%	14%	14%	14%

Exceedance 75% — **Top 5% Vs. Exceedance**

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1 **Jan**	-11%	-11%	-10%	-10%	-10%	-10%	-10%	-10%	-9%	-8%	-7%	-8%	-7%	-8%	-9%	-9%	-9%	-10%	-10%	-11%	-10%	-10%	-10%	-10%
2 **Feb**	-18%	-19%	-18%	-17%	-16%	-15%	-17%	-17%	-17%	-18%	-18%	-17%	-17%	-17%	-17%	-16%	-12%	-12%	-13%	-13%	-14%	-14%	-14%	-14%
3 **Mar**	-12%	-12%	-13%	-13%	-15%	-14%	-14%	-13%	-13%	-13%	-14%	-14%	-14%	-16%	-17%	-17%	-18%	-18%	-18%	-17%	-17%	-17%	-16%	-15%
4 **Apr**	-21%	-21%	-22%	-21%	-21%	-22%	-20%	-19%	-17%	-16%	-16%	-15%	-14%	-15%	-17%	-18%	-19%	-21%	-19%	-20%	-20%	-20%	-21%	-26%
5 **May**	-20%	-18%	-19%	-20%	-19%	-19%	-17%	-16%	-18%	-18%	-18%	-16%	-16%	-17%	-17%	-17%	-15%	-14%	-10%	-16%	-17%	-18%	-18%	-22%
6 **Jun**	-16%	-14%	-14%	-16%	-14%	-14%	-15%	-17%	-16%	-14%	-13%	-12%	-11%	-11%	-13%	-14%	-16%	-11%	-8%	-14%	-15%	-16%	-18%	-18%
7 **Jul**	-6%	-5%	-8%	-10%	-10%	-10%	-11%	-12%	-10%	-11%	-11%	-10%	-11%	-11%	-13%	-12%	-9%	-7%	-6%	-7%	-5%	-7%	-6%	-6%
8 **Aug**	-3%	-1%	-3%	-7%	-7%	-5%	-6%	-8%	-8%	-8%	-9%	-10%	-9%	-10%	-12%	-9%	-8%	-6%	-2%	0%	0%	-2%	-2%	-3%
9 **Sep**	-21%	-18%	-19%	-18%	-18%	-19%	-19%	-19%	-17%	-13%	-12%	-10%	-9%	-9%	-11%	-14%	-15%	-15%	-17%	-20%	-23%	-27%	-28%	-28%
10 **Oct**	-10%	-10%	-12%	-11%	-10%	-10%	-9%	-8%	-7%	-7%	-9%	-9%	-9%	-9%	-9%	-9%	-10%	-9%	-10%	-12%	-14%	-17%	-17%	-16%
11 **Nov**	-12%	-12%	-11%	-11%	-10%	-9%	-8%	-9%	-9%	-10%	-10%	-10%	-10%	-10%	-10%	-10%	-10%	-10%	-10%	-10%	-10%	-12%	-13%	-14%
12 **Dec**	-15%	-14%	-14%	-13%	-13%	-13%	-14%	-13%	-12%	-12%	-13%	-12%	-12%	-12%	-11%	-10%	-9%	-9%	-10%	-11%	-12%	-12%	-13%	-13%

NP15 Exceedance 50% — **Top 5% Vs. Exceedance**

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1 Jan	-7%	-8%	-8%	-7%	-7%	-6%	-7%	-7%	-6%	-6%	-5%	-4%	-4%	-5%	-6%	-6%	-6%	-7%	-7%	-7%	-6%	-5%	-5%	-5%
2 Feb	-7%	-8%	-8%	-10%	-9%	-9%	-9%	-10%	-11%	-12%	-12%	-11%	-11%	-10%	-9%	-8%	-6%	-6%	-6%	-6%	-6%	-6%	-6%	-5%
3 Mar	-2%	-3%	-2%	-4%	-6%	-6%	-7%	-7%	-7%	-8%	-8%	-7%	-9%	-10%	-11%	-10%	-10%	-9%	-7%	-7%	-5%	-6%	-5%	-4%
4 Apr	-4%	-5%	-4%	-5%	-5%	-7%	-6%	-8%	-8%	-5%	-6%	-6%	-6%	-6%	-5%	-2%	-2%	-2%	-1%	-2%	-1%	-4%	-5%	-5%
5 May	1%	2%	2%	1%	0%	-1%	-1%	1%	1%	0%	-3%	-3%	-3%	0%	-1%	1%	5%	8%	12%	7%	4%	1%	1%	-2%
6 Jun	7%	5%	5%	6%	5%	5%	4%	4%	5%	6%	5%	6%	4%	4%	8%	9%	9%	9%	7%	7%	7%	5%	7%	6%
7 Jul	6%	6%	7%	9%	8%	7%	5%	4%	5%	3%	5%	5%	5%	6%	7%	8%	8%	7%	7%	7%	8%	9%	7%	7%
8 Aug	14%	15%	14%	14%	13%	13%	12%	11%	12%	9%	6%	4%	4%	5%	7%	9%	13%	15%	16%	15%	13%	13%	13%	15%
9 Sep	7%	7%	5%	6%	5%	-1%	0%	3%	3%	1%	-1%	-2%	-2%	-3%	-3%	-4%	0%	3%	2%	-1%	-1%	-3%	-2%	-3%
10 Oct	4%	2%	0%	-1%	0%	-2%	-2%	-2%	-2%	-2%	-2%	-4%	-4%	-4%	-4%	-5%	-4%	-5%	-2%	-2%	-3%	-3%	-3%	-2%
11 Nov	-6%	-7%	-6%	-5%	-6%	-5%	-5%	-5%	-7%	-7%	-8%	-8%	-8%	-8%	-8%	-8%	-8%	-7%	-7%	-7%	-7%	-7%	-7%	-8%
12 Dec	-9%	-9%	-9%	-8%	-9%	-8%	-10%	-9%	-8%	-8%	-9%	-8%	-9%	-9%	-7%	-7%	-6%	-5%	-5%	-5%	-5%	-6%	-6%	-6%

Similarly, the most limiting month for SP-15 wind resources during summer months is June while the most limiting month for non-summer months is April.

Figure 66: Difference Between Generation Profiles – SP15

Average Generation on Top 5% Days in SP15 Resources (2015-2020)

Hour Ending

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1 Jan	15%	15%	14%	14%	13%	13%	13%	12%	11%	11%	11%	11%	12%	13%	14%	14%	14%	14%	14%	13%	13%	13%	13%	13%
2 Feb	17%	16%	16%	15%	14%	14%	13%	12%	12%	13%	14%	14%	16%	17%	17%	17%	17%	16%	15%	15%	15%	14%	14%	13%
3 Mar	20%	19%	18%	18%	17%	15%	14%	14%	13%	13%	13%	14%	15%	16%	18%	20%	22%	22%	23%	23%	23%	23%	22%	22%
4 Apr	33%	32%	31%	29%	27%	25%	22%	19%	16%	16%	16%	17%	19%	21%	23%	26%	29%	31%	32%	32%	33%	34%	33%	32%
5 May	40%	38%	36%	34%	31%	27%	24%	20%	16%	15%	14%	14%	14%	16%	19%	24%	29%	34%	36%	37%	39%	39%	39%	39%
6 Jun	35%	34%	31%	29%	25%	21%	17%	14%	11%	9%	8%	9%	10%	12%	16%	21%	25%	29%	32%	34%	37%	37%	37%	36%
7 Jul	36%	35%	32%	29%	26%	23%	19%	15%	11%	9%	8%	9%	10%	13%	17%	22%	27%	32%	35%	37%	38%	39%	39%	37%
8 Aug	32%	31%	29%	27%	23%	20%	16%	13%	9%	8%	7%	8%	10%	12%	16%	21%	26%	30%	33%	36%	37%	37%	36%	34%
9 Sep	16%	15%	14%	12%	10%	9%	7%	6%	5%	5%	6%	7%	8%	10%	11%	14%	15%	16%	18%	21%	22%	21%	21%	20%
10 Oct	11%	11%	10%	9%	9%	8%	7%	6%	5%	5%	5%	6%	7%	7%	8%	9%	10%	11%	11%	13%	13%	13%	13%	13%
11 Nov	13%	13%	13%	12%	12%	11%	11%	11%	11%	12%	13%	14%	15%	16%	16%	17%	17%	16%	15%	15%	15%	14%	14%	13%
12 Dec	13%	13%	12%	12%	12%	12%	12%	12%	12%	12%	13%	14%	15%	16%	16%	16%	15%	14%	15%	15%	15%	14%	14%	12%

SP15 Avg **Top 5% Vs. Exceedance**

Exceedance %		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
75%	1 Jan	-13%	-13%	-12%	-12%	-11%	-12%	-11%	-10%	-9%	-9%	-9%	-10%	-10%	-11%	-13%	-12%	-12%	-12%	-11%	-11%	-11%	-11%	-11%	-11%
	2 Feb	-13%	-13%	-13%	-12%	-11%	-11%	-10%	-9%	-9%	-10%	-11%	-12%	-13%	-14%	-14%	-14%	-13%	-12%	-11%	-11%	-11%	-10%	-9%	-9%
	3 Mar	-11%	-11%	-11%	-12%	-10%	-9%	-9%	-9%	-10%	-10%	-10%	-10%	-10%	-11%	-13%	-15%	-15%	-12%	-14%	-13%	-13%	-14%	-14%	-15%
	4 Apr	-14%	-13%	-13%	-14%	-13%	-14%	-13%	-12%	-11%	-10%	-10%	-11%	-12%	-13%	-14%	-14%	-13%	-10%	-10%	-10%	-9%	-10%	-10%	-10%
	5 May	-11%	-10%	-10%	-9%	-10%	-10%	-10%	-10%	-9%	-8%	-8%	-8%	-8%	-9%	-11%	-8%	-7%	-7%	-6%	-7%	-7%	-7%	-9%	-10%
	6 Jun	-1%	-1%	-2%	-2%	0%	0%	-1%	-1%	-3%	-3%	-4%	-3%	-3%	-5%	-6%	-5%	-4%	-3%	-1%	0%	-1%	-2%	-2%	-2%
	7 Jul	-8%	-9%	-8%	-9%	-8%	-8%	-7%	-7%	-6%	-6%	-5%	-5%	-6%	-7%	-8%	-9%	-9%	-8%	-8%	-10%	-8%	-8%	-9%	-7%
	8 Aug	-7%	-7%	-8%	-8%	-8%	-7%	-7%	-6%	-5%	-5%	-5%	-5%	-6%	-7%	-9%	-10%	-11%	-10%	-10%	-10%	-9%	-7%	-8%	-8%
	9 Sep	-6%	-7%	-8%	-7%	-6%	-4%	-4%	-3%	-3%	-3%	-3%	-3%	-4%	-5%	-7%	-9%	-9%	-8%	-6%	-8%	-10%	-10%	-10%	-10%
	10 Oct	-7%	-7%	-6%	-5%	-5%	-5%	-4%	-3%	-2%	-3%	-3%	-4%	-4%	-4%	-5%	-6%	-7%	-8%	-7%	-8%	-8%	-8%	-8%	-9%
	11 Nov	-11%	-11%	-10%	-10%	-10%	-9%	-8%	-9%	-9%	-10%	-11%	-12%	-13%	-14%	-14%	-15%	-15%	-14%	-13%	-12%	-12%	-12%	-11%	-11%
	12 Dec	-10%	-9%	-9%	-9%	-9%	-9%	-9%	-9%	-9%	-10%	-10%	-11%	-12%	-13%	-13%	-13%	-12%	-12%	-11%	-11%	-12%	-11%	-10%	-9%

SP15 Avg **Top 5% Vs. Exceedance**

Exceedance %		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
62%	1 Jan	-11%	-11%	-11%	-10%	-10%	-9%	-9%	-8%	-8%	-7%	-7%	-8%	-8%	-9%	-10%	-10%	-11%	-10%	-10%	-9%	-9%	-9%	-9%	-10%
	2 Feb	-10%	-11%	-10%	-10%	-9%	-9%	-8%	-7%	-7%	-9%	-9%	-9%	-11%	-11%	-10%	-9%	-8%	-7%	-7%	-8%	-7%	-7%	-6%	-5%
	3 Mar	-5%	-4%	-5%	-5%	-3%	-4%	-5%	-5%	-6%	-6%	-6%	-5%	-5%	-5%	-5%	-6%	-6%	-5%	-4%	-4%	-6%	-6%	-6%	-8%
	4 Apr	-4%	-2%	-2%	-3%	-4%	-5%	-3%	-4%	-4%	-4%	-3%	-5%	-6%	-7%	-6%	-3%	-2%	-1%	0%	0%	-3%	-3%	-3%	-2%
	5 May	-4%	-3%	-2%	0%	-1%	-2%	-3%	-3%	-3%	-5%	-4%	-5%	-4%	-4%	-1%	-2%	0%	0%	0%	-1%	-3%	-1%	-1%	-2%
	6 Jun	6%	5%	8%	5%	6%	5%	4%	3%	1%	0%	0%	-1%	-1%	-2%	-1%	0%	4%	5%	7%	8%	5%	4%	4%	4%
	7 Jul	0%	-1%	-1%	-2%	-2%	-3%	-4%	-4%	-4%	-4%	-4%	-3%	-4%	-4%	-4%	-4%	-3%	-2%	0%	-2%	-1%	0%	-1%	1%
	8 Aug	-1%	-2%	-2%	-3%	-3%	-3%	-3%	-2%	-3%	-3%	-3%	-3%	-4%	-4%	-5%	-6%	-5%	-6%	-5%	-5%	-3%	-2%	-2%	-3%
	9 Sep	-1%	-1%	-2%	-3%	-2%	-2%	-1%	-1%	-1%	-1%	-2%	-2%	-3%	-3%	-5%	-6%	-5%	-3%	-1%	-2%	-3%	-2%	-3%	-3%
	10 Oct	-3%	-3%	-2%	-2%	-2%	-2%	-1%	-1%	-1%	-1%	-2%	-2%	-2%	-2%	-3%	-4%	-4%	-4%	-3%	-4%	-3%	-4%	-4%	-4%
	11 Nov	-10%	-9%	-9%	-9%	-8%	-8%	-7%	-8%	-8%	-8%	-9%	-10%	-11%	-12%	-13%	-13%	-14%	-12%	-11%	-10%	-10%	-10%	-10%	-10%
	12 Dec	-8%	-8%	-8%	-8%	-7%	-8%	-8%	-7%	-8%	-8%	-9%	-10%	-11%	-11%	-11%	-11%	-10%	-9%	-9%	-8%	-9%	-9%	-8%	-7%

MRP compared the Top 5% days Benchmark against the Top 5 Peak days benchmark profiles to see if there were significant differences between the two benchmarks. The results are from the following formula: (Top 5% Benchmark – Top 5 Days Benchmark) / (Top 5 Days Benchmark). If the value is negative, then the Top 5% Benchmark yielded a lower capacity value whereas a positive value means the Top 5% Benchmark was higher than the Top 5 Day capacity value for that hour of that month.

Table 24: Top 5% vs Top 5 Days - Solar

Solar — Top 5% vs Top 5 Days Benchmarks

Month	HE 1	HE2	HE 3	HE 4	HE 5	HE 6	HE 7	HE 8	HE 9	HE 10	HE 11	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20	HE 21	HE 22	HE 23	HE 24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	4%	4%	4%	5%	7%	14%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	13%	9%	7%	5%	5%	5%	5%	5%	6%	14%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	-47%	-24%	-12%	-7%	-5%	-4%	-3%	-3%	-4%	-3%	7%	30%	24%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	#DIV/0!	0%	-6%	-5%	-4%	-3%	-3%	-3%	-3%	-3%	-4%	-3%	-4%	-5%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	-10%	-5%	-3%	-2%	-1%	0%	-2%	-2%	-2%	-2%	-3%	-3%	-7%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	2%	2%	0%	0%	0%	-1%	-1%	1%	1%	1%	3%	3%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	3%	2%	1%	1%	1%	1%	-1%	3%	4%	3%	4%	7%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	4%	4%	1%	1%	0%	1%	1%	1%	3%	3%	4%	5%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	6%	4%	3%	3%	3%	3%	3%	4%	5%	5%	6%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	2%	2%	1%	3%	1%	3%	3%	3%	4%	6%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	#DIV/0!	#DIV/0!	0%	-4%	-2%	-3%	-3%	-2%	-3%	-3%	-2%	-6%	-16%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	-3%	-4%	-4%	-4%	-4%	-2%	-2%	-4%	0%	0%	0%	0%	0%	0%	0%	0%

Table 25: Top 5% vs Top 5 Days - NP15

NP15 Wind — Top 5% vs Top 5 Days

Month	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
1	13%	11%	-3%	-12%	-16%	-19%	-20%	-20%	-23%	-16%	-15%	-15%	-20%	-31%	-34%	-31%	-25%	-25%	-25%	-31%	-29%	-25%	-20%	-17%
2	-18%	-24%	-25%	-27%	-26%	-24%	-21%	-21%	-26%	-26%	-26%	-29%	-25%	-19%	-19%	-16%	-10%	-17%	-18%	-18%	-17%	-17%	-18%	-17%
3	-6%	2%	3%	0%	-6%	-1%	8%	8%	9%	6%	4%	7%	12%	1%	0%	-1%	-7%	-16%	-17%	-15%	-20%	-22%	-22%	-19%
4	4%	2%	4%	2%	4%	13%	15%	13%	16%	16%	27%	31%	35%	39%	39%	30%	20%	13%	9%	5%	3%	3%	0%	-1%
5	9%	9%	9%	9%	8%	7%	8%	10%	10%	9%	14%	19%	20%	23%	18%	11%	11%	8%	2%	3%	0%	2%	1%	2%
6	5%	6%	6%	7%	10%	12%	12%	15%	17%	19%	19%	18%	20%	19%	15%	9%	6%	5%	5%	3%	3%	2%	3%	3%
7	4%	4%	5%	6%	9%	11%	10%	11%	11%	14%	13%	13%	15%	9%	10%	6%	9%	8%	9%	7%	8%	8%	6%	5%
8	7%	6%	4%	5%	7%	8%	11%	10%	10%	12%	12%	10%	9%	15%	10%	11%	9%	8%	4%	2%	3%	2%	-1%	-1%
9	10%	11%	12%	12%	13%	12%	8%	5%	3%	3%	4%	3%	2%	11%	11%	9%	8%	2%	2%	2%	4%	3%	2%	4%
10	-4%	-9%	-13%	-18%	-22%	-24%	-23%	-23%	-23%	-25%	-23%	-20%	-20%	-17%	-12%	-6%	0%	0%	-4%	-1%	1%	-1%	0%	-2%
11	8%	11%	20%	43%	57%	56%	92%	96%	115%	147%	164%	186%	96%	84%	77%	73%	49%	38%	30%	32%	18%	13%	9%	1%
12	-14%	-11%	-14%	-13%	-15%	-17%	-14%	-12%	-9%	-11%	-7%	-12%	-18%	-16%	-17%	-14%	-9%	-8%	-1%	6%	11%	14%	10%	6%

Table 26: Top 5% vs Top 5 Days - SP15

SP15 Wind — Top 5% vs Top 5 Days

Month	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
1	-5%	-3%	-2%	-7%	-11%	-15%	-17%	-14%	-12%	-10%	-12%	-15%	-14%	-14%	-13%	-18%	-20%	-17%	-16%	-20%	-20%	-21%	-26%	-29%
2	-14%	-13%	-12%	-9%	-9%	-11%	-14%	-18%	-22%	-27%	-29%	-26%	-26%	-24%	-21%	-17%	-14%	-16%	-15%	-16%	-10%	-12%	-17%	-20%
3	11%	12%	16%	18%	32%	50%	46%	35%	27%	24%	20%	20%	27%	24%	14%	15%	27%	31%	30%	25%	22%	23%	22%	21%
4	19%	19%	18%	21%	28%	33%	34%	41%	44%	47%	52%	52%	58%	57%	51%	42%	31%	22%	17%	15%	15%	16%	12%	10%
5	-1%	-1%	-1%	1%	4%	4%	6%	11%	22%	33%	43%	51%	50%	48%	36%	28%	18%	12%	8%	10%	7%	6%	7%	8%
6	13%	14%	15%	14%	14%	12%	11%	11%	16%	18%	18%	18%	14%	11%	9%	7%	7%	6%	6%	6%	5%	5%	5%	6%
7	6%	5%	5%	5%	7%	8%	12%	18%	24%	34%	43%	39%	32%	25%	22%	15%	9%	8%	7%	4%	6%	6%	3%	4%
8	6%	7%	7%	10%	9%	9%	13%	18%	23%	29%	30%	25%	25%	21%	24%	20%	19%	16%	14%	15%	12%	11%	10%	9%
9	11%	9%	5%	5%	5%	5%	4%	4%	4%	6%	10%	6%	3%	5%	2%	-4%	-4%	-3%	-2%	1%	0%	-2%	-3%	-2%
10	54%	44%	39%	34%	36%	31%	22%	13%	3%	3%	2%	3%	3%	2%	7%	13%	16%	16%	13%	24%	20%	17%	11%	6%
11	57%	64%	77%	81%	89%	94%	119%	128%	126%	115%	104%	100%	75%	84%	82%	79%	68%	64%	65%	59%	57%	44%	38%	49%
12	-18%	-16%	-18%	-18%	-13%	-11%	-10%	-11%	-15%	-14%	-16%	-16%	-14%	-15%	-13%	-13%	-15%	-15%	-9%	-4%	-5%	-3%	-6%	-8%

These tables show significant differences in the benchmarks because daily generation data is not similar. Using the Top 5% load days will inherently include more variability in the data but also will create a more robust benchmark that is more representative of resource output. MRP believes introducing more data into the benchmark helps with defining the exceedance levels of these resources.

MRP has discussed the definition of stressed days with CAISO. The CAISO considers stressed days as days in which the CAISO has issued a flex alert. While this is a reasonable metric, it's not easy to formulate. MRP's Top 5% metric covers a significant majority of flex alert days during summer months. Given that the CAISO generally does not call Flex Alert days during non-summer months, it is not possible to identify benchmarking days using the Flex Alert metric in those non-summer months. CAISO provided more recent data for 2021 and 2022 to MRP to compare the top 5% days metric. Aside from the very recent September 2022 heatwave, the top 5% metric still captured a significant majority of days during summer of 2021 – 2022. September 2022 had 10 straight days of Flex Alerts, and due to the new all-time peak day on September 6th, it skewed the Top 5% cutoff more to the extreme and left out about 4 of the total 10 days of Fex Alerts. In order to capture the total 10 days of Flex Alerts, the "top X%" cutoff metric would need to be the top 8% of load days. MRP generally believes that the top 8% metric is also reasonable at this time because currently the grid is tight and unable to maintain 0.1 LOLE. As LSEs build and bring on additional new capacity to maintain reliability, the number of Flex Alert notices should hopefully drop. When that occurs, the question will again be asked, how do we define a "stressed day"? But in the interim, the Top 5% of load hours is sufficient for capacity counting purposes of the initial implementation phase of the new RA framework. MRP invites the CAISO to comment on its preference and reasoning of the metric that should be used to develop a benchmark to determine the exceedance thresholds of renewable resources.

MRP proposes the exceedance profiles should be updated every two (2) years to incorporate new generation capacity as well as new load shapes as the grid moves towards a net zero carbon future. MRP did not consider whether the dataset for the benchmarking and exceedance calculation should be on a rolling five- or six-year basis or if it should include all data available since 2015 up to the most current available; MRP calculated these values based on six years of data because PG&E was able to aggregate and download the data from the CAISO's website. The Commission may consider whether more granular locational regions and specific technology types should also be calculated, additional seasons or monthly exceedance values should be established, and if each resource should have its own calculated exceedance profile rather than one that's based on a group of technologies. Generally speaking, individual resource exceedance values may be useful such that certain resources are not harmed by performance of other resources. The current analysis does not account for CAISO curtailments for reliability or economics and thus lower than actual potential output of the VERs. MRP does not offer a solution for reconstituting the curtailed volumes back into the dataset but notes that this may be a future issue for consideration.

MRP also reviewed other techniques that attempt to derive the exceedance threshold value to the change in resulting PRM. This is because, as noted above, the PRM depends on the capacity values assigned to the portfolio of resources. Therefore, if the capacity value of the portfolio increases 10MWs, then the PRM would also increase by an equivalent percentage amount. But ultimately this is of dubious value because the portfolio is still the same and the capacity valuation of that portfolio does not affect whether that portfolio achieved a 0.1 LOLE. There is very little benefit to calculating the exceedance threshold this way as it does not measure how these resources may generate during "stressed days".

Energy Storage:

Battery energy storage systems (BESS) qualifying capacity (QC) methodology should remain the status quo, which uses the Pmax, limited by deliverability of the resource. LSEs would be able to manually select the slice in which the resource's capacity would be used. Alternatively, the compliance templates may customize this solution for the LSE. The compliance template may not divide the capacity into partial values to extend the duration of the battery use, this may require manual intervention.

Dispatchable Hydro:

Hydro-resource QC methodology also remains the status quo. A single QC value based on historic capability with emphasis on drought years would be applied to all slices of the day. MRP questions whether energy duration based on hydro level availability should be considered so that the slice of day can mimic the expected must offer of the hydro resource in the CAISO markets. Hydro resources are able to manage their availability due to water levels with the CAISO and therefore may not be available during certain slices.

Hybrid Resources:

Hybrid resources present a unique challenge because the BESS that's at the site may charge from the onsite generator or may be allowed to grid charge. The current QC methodology essentially takes away a certain amount of capacity value from the onsite generator to ensure the BESS can be fully charged. This methodology is limited to hybrid resources that are prohibited from grid charging due to ITC constraints. However, given the latest changes from the Inflation Reduction Act, MRP believes that using the exceedance methodology to set QC values for hybrid resources may be more appropriate because historical hourly charge/discharge values will be more precise than the current methodology. This exceedance methodology would develop 24 hourly QC values for the SOD framework which would include both the charging and discharging/generation output of the hybrid resource for all hours of the day. This methodology would capture profiles for resources that are limited to onsite charging as well as profiles of hybrid resources that are not limited without need for differentiation.

MRP believes that exceedance methodology could not be applied in previous years because of the lack of data for this type of resource, however many hybrid resources have come online and data is available. As an initial step, MRP proposes to use an 80% exceedance threshold for the QC methodology for hybrid resources for all monthly calculations. This is based on the solar exceedance threshold for summer months. MRP expects that Commission staff may wish to gather additional information to modify the exceedance threshold in future years of the RA proceeding.

Co-located Resources:

Co-located resources should generally maintain the status quo for QC counting methodology with the exception that the VER resource QC counting methodology should be switched from ELCC to the new exceedance methodology described above.

Thermal Resources:

Dispatchable thermal resources should continue to use the current QC methodology. MRP does not believe a sufficient record has been developed during the workshop process to implement a UCAP or UCAP-lite methodology. MRP recommends that the CPUC work with the CAISO to develop a comprehensive solution to ensuring resources are able to find substitute capacity for all outages in a cost effective and efficient manner before implementing a UCAP methodology. Currently, it is very difficult for resources to procure substitute capacity for outages, both planned and forced, which has an impact on the reliability of the grid as well as on costs to customers.

Imports:

Import resources should be divided into resource-specific and non-resource specific resources. Resource-specific resources are dynamically-transferred resources (pseudo tied and dynamically scheduled resources). Resource-specific resources should use the QC methodology associated with the resource's technology. Non-resource specific resources should use the capacity amount associated with the underlying contract. Both types of imports require an allocation of CAISO MIC to count as RA capacity for the LSE. In order to count variable energy resources importing energy into the CAISO, MRP proposes that the LSE or the scheduling coordinator must obtain sufficient MIC capacity to cover the highest hourly generation capacity of the resource. In other words, if the LSE has 50MWs of MIC for solar resource with an hourly generation profile of 75MWs at HE12, the LSE would be limited to showing only 50MWs of RA capacity due to the MIC limitation. Requiring that import resources acquire MIC is analogous to ensuring the deliverability of internal CAISO resources and this policy should be consistent for resources both into and external to the CAISO balancing area authority.

MRP proposes that LSEs should only be allowed to show import capacity in the hours for which the import is contracted. If the import contract is for a 6x16 product, then the LSE can only show capacity values for those 16 hours. MRP has additional concerns with the situation in which insufficient capacity is procured to meet all seven days per week (e.g., through 6x16 contracts) because the SOD framework looks only at a single day in the month. MRP further discusses this topic in the MCC Bucket portion of the proposal.

Energy Sufficiency

A critical component of the SOD framework is to ensure that LSEs procure sufficient energy in the form of capacity to charge their storage resources. SCE has developed an LSE compliance template that measures charging energy sufficiency. MRP finds this to be generally acceptable, though MRP has two remaining concerns. The first concern was raised by Clean Power Alliance (CPA), namely, SCE's template does not constrain the storage resource to an instantaneous charging limit. For example, a 100MW/400MWh storage resource is able to pass validation in the template if the LSE showed 400MWh of surplus energy in a single hour. If the storage resource can only charge at 100 MW per hour then the template should be revised to have this limit. MRP agrees with the issue raised by CPA and believes that SCE's compliance template should be updated for this error. The second concern, identified by SCE, is that the template primarily works for storage resources that have a single cycle-per-day limitation and does not enforce charging requirements for storage resources with more than one cycle per day. It is unclear how large of an issue this is at the moment, but it may require additional consideration in the future as more multi-cycle storage resources come online.

Some pumped hydro resources use grid energy to pump. These resources effectively operate as huge grid batteries that require grid charging. MRP proposes that LSEs that contract with these pumped hydro resources also should be required to show that sufficient energy is also procured to pump the water. This information can be stored in the master resource database so that the LSE compliance template differentiates which pumped hydro resource requires energy sufficiency validation.

Compliance templates/Master Resource Database

The master database is expected to contain information for resources that qualify as RA resources. MRP believes this database should be developed with the intention and understanding of how the data will be used. If data will not be used for validation or compliance purposes, then it should not be included in the master resource database to avoid any risk of making market sensitive information public.

MRP suggests that the database should include the following required information and will provide discussion for why some of these fields may or may not be necessary

1. Resource ID
2. Resource Name
3. Technology Type
4. Pmax
5. Charging Max
6. Duration
7. Start Hour Availability
8. End Hour Availability
9. Losses or Charging Efficiency
10. Cycles Per Day (Storage)
11. Exceedance profile

Pmax and Exceedance Profile

MRP expects that the master resource database will feed into the LSE compliance templates and be used to calculate certain information, such as hourly QC values, for resources. This data will be primarily used by wind, solar and hybrid resources that depend on exceedance profiles. Essentially, the RA compliance template would use a formula of Pmax * Exceedance Profile to calculate the hourly QC value. This could replace the NQC file that's published by the CPUC or the CAISO for these types of resources. However, if CPUC and CAISO will still publish separate hourly NQC files for each resource, then the Pmax and exceedance profiles may not be necessary at all because it wouldn't be used in the compliance templates.

Charging Maximum

Maximum charge would be used by compliance templates to validate and limit the amount of instantaneous energy the storage resource can accept so that a four-hour resource cannot fully charge in a single hour, for example. This would be for both storage resources as well as pumped hydro resources that require utilize grid energy to pump water to the reservoir.

Start and End Hour Availability

Certain resources have daily operating hours such as an inability to generate electricity between midnight to 6 am. As such, such resources should not be shown within those hours.

Cycles Per Day

Storage resources generally have duration limits, but also have cycle limitations. The current RA templates assume BESS have one daily cycle but they also have the capability to allow for multi-cycle resources. While the RA compliance templates should account for multiple cycles, the main question that then emerges is how do the templates ensure the resource is fully charged in order to count for its next cycle?

Compliance Templates

SCE provided draft versions of the compliance templates and MRP appreciates SCE for its heavy lifting on this topic. MRP requests the Commission consider the elements of the master resource database discussed above and the involvement in the RA templates to ensure, to the extent possible, that confidential information is not made public. That may require SCE working with Energy Division staff, after the Commission decision, to make necessary edits prior to the test year.

Test Year

The Commission agreed with several parties that a 2024 test year is advisable.118 The Commission directed parties to develop proposals for the 2024 shadow compliance year.

Several questions come to mind as to what "shadow compliance" means.

1. What (e.g., templates and systems or requirements) is being tested?
2. Should LSEs procure additional capacity to meet SOD requirements if they've met their existing RA requirements?
3. What are the exit criteria for the test year?

What is being tested?

While the general belief that shadow compliance is useful to work out any issues, it is necessary to set a baseline first so that the Commission may compare results and determine why certain issues may occur. MRP understands that shadow compliance will not include any penalties for LSEs. However, the SOD portfolio of resources and the SOD PRM should be compared to the portfolio resulting from the correct annual PRM of the existing RA framework; this means that the existing PRM must be set based on the LOLE study from Energy Division, and not assumed to be the 17% value referred to in D.22-06-050.119 Using an incorrect PRM for the existing RA framework that's not derived from the LOLE study will result in an apples to oranges comparison and LSEs may find themselves deficient in meeting their SOD RA obligations. While MRP understands this may be an RA implementation Phase 3 issue to be raised in January 2023, it is nevertheless important to highlight it here as the test year does not require LSEs to procure additional capacity to meet the SOD RA obligations.

Test year exit criteria

Exit criteria should be established in order to know whether the test year is successful and can be fully implemented. Specifically, can test year proceed to implementation and if not, what are the necessary steps required to fix various issues?

First and foremost, a test year for a new RA framework does not only impact LSEs and CPUC staff. It impacts the CEC, which is already proceeding with updates to the load forecast process. It impacts the CAISO because it needs to update its validation templates and internal and external facing software. It will impact scheduling coordinators for LSEs and RA resources because they must submit showings to

[118] D.22-06-050 at page 76 ("Given the complexities of implementing a new statewide RA framework, we find it prudent to consider a test year in 2024 to allow additional time for implementation and potential adjustments.")
[119] D.22-06-050 at page 92, Ordering Paragraph 8.

the CAISO. The CAISO has stated that it expects to start its own initiative in order to implement SOD RA framework but at the same time it also has other Local Regulatory Authorities (LRAs) that will still remain on the existing RA framework. As such it needs to ensure that it can maintain reliability with multiple RA frameworks. That said, MRP believes it is reasonable to assume that CAISO's schedule for implementing any systems and tariff changes it believes are necessary will be November 2024 for the 2025 compliance year. Consequently, market simulation testing will occur between September and October of 2024. Therefore, the first exit criteria should be whether the CAISO's systems are ready for the 2025 compliance year. It is possible that software changes will not be ready for the 2025 year ahead showings, therefore the first opportunity would be January 2025 month-ahead showings.

Aside from CAISO software issues, if there are structural issues found by Energy Division throughout 2024 test year, then the Commission should allow parties and Energy Division to seek solutions before test year ends. MRP proposes that Energy Division publish a report after each of the test year compliance showings to identify any structural, template or systems deficiencies and report on LSEs' deficiencies in an aggregated format to maintain confidentiality. This would provide the Commission and parties with information as to whether changes are necessary. Parties and Energy Division should be allowed to submit proposals and solutions to any issues that arise during the 2024 test year so that the Commission can adopt necessary changes prior to the 2025 compliance year.

<u>Test Year Details</u>

LSEs should submit a year-ahead 24-SOD RA showing on November 30, 2023 for 90% of the May through October 2024 compliance requirements. LSEs must meet their three-year forward Local RA obligations, if any, and 90% of their Flexible RA obligations for all months of 2024.

LSEs should submit month-ahead 24-SOD RA showings for March, June, September 2024 to meet 100% of their 24-SOD demand + SOD PRM. Each month-ahead showing should be due by the 1st day of the applicable compliance month to the CPUC. These showings must be signed by an officer of the LSE that represents the LSE. LSEs must continue to meet 100% of their Local and Flexible RA obligations for the SOD RA showing months during the test year. MRP selected these months mainly because some months offered lower exceedance values while others offered higher ones to meet various load conditions. Months in the fourth quarter were not selected because it's too late to identify issues and seek resolution prior to the 2025 Compliance year, particularly if doing so required Commission decisions. Additional months for which test year showings should be submitted can be added to this schedule prior to September. Nothing prevents LSEs from testing out their monthly portfolios for other months on their own.

During the test year, LSEs will also receive RA credits updates from Energy Division for traditional CAM allocations, CPE allocations, Modified CAM allocations, RMR credits and load migration.

Additional testing could be performed, such as on impacts from planned outage substitutions; however, it is difficult to plan those testing requirements out at this time without knowing the CAISO's plans for its implementation schedule. Therefore, MRP does not have a suggestion for additional testing at this time.

V. Conclusion and Next Steps

Authors: PG&E

The proposals included in this workshop report are for stakeholder and Commission consideration in establishing changes to the Resource Adequacy program for 2025 and beyond (including the 2024 test year process). As outlined in the introduction, stakeholders will have an opportunity to submit comments on the report on December 1, 2022 and reply comments on December 12, 2022. A Commission proposed decision is expected in Q1 2023.

VI. Appendices

a. Workshop Notes

I. Workshop 1: 7/27/2022

Authors: CLECA

https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/7-27-2022-solar-and-wind-exceedance/workshop-1_notes_220727.docx

II. Workshop 2: 8/3/2022

Authors: CLECA

https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-3-2022-lse-compliance-tools/notes-from-ra-reform-workshop-8-3-22.docx

III. Workshop 3: 8/10/2022

Authors: CLECA

https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-10-2022-hybrid-resource-counting/notes-from-august-10-22-workshop.docx

IV. Workshop 4: 8/17/2022

Authors: CLECA

https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/-/media/eb80f9a5159b49288bf848771f4c52a1.ashx

V. Workshop 5: 8/23/2022

Authors: CLECA

https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-23-2022-planning-reserve-margin/workshop-5_notes_08-23-22.docx

VI. Workshop 6: 8/31/2022

Authors: CLECA

https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/8-31-2022-planning-reserve-margin/notes-from-8-31-22-working-group-meeting-updated.docx

VII. Workshop 7: 9/14/2022

Authors: CLECA

https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-14-2022-planning-reserve-margin-part-2/workshop-7_notes_9-14-2022.docx

VIII. Workshop 8: 9/21/2022

Authors: CLECA

https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-21-2022-cpuc-caiso-processes/workshop-8_notes_9-21-22.docx

IX. Workshop 9: 9/29/2022

Authors: CLECA

https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/9-29-2022-test-year-follow-up-on-remaining-issues/notes-from-september-29-2022-ra-reform-workshop.docx

X. Workshop 10: 10/6/2022

Authors: CLECA

https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/10-6-2022-wrap-up/notes-from-10-6-22-ra-reform-workshop.docx