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**STATE OF CALIFORNIA**
**CALIFORNIA ENERGY COMMISSION**

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| In the Matter of:<br><br>The 2023 Integrated Energy Policy Report | Docket No.: 23-IEPR-01 |

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE DRAFT 2023 INTEGRATED ENERGY POLICY REPORT**

Evelyn Kahl,
General Counsel and Director of Policy
Andrew Mills,
Director of Data Analytics
Leanne Bober,
Senior Counsel
CALIFORNIA COMMUNITY CHOICE ASSOCIATION
One Concord Center
2300 Clayton Road, Suite 1150
Concord, CA 94520
(510) 980-9459
regulatory@cal-cca.org

December 1, 2023

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| In the Matter of:<br><br>The 2023 Integrated Energy Policy Report | Docket No.: 23-IEPR-01 |

**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE DRAFT 2023 INTEGRATED ENERGY POLICY REPORT**

The California Community Choice Association[1] (CalCCA) submits these comments to the California Energy Commission (Commission) on the *Draft 2023 Integrated Energy Policy Report*, dated November 13, 2023 (Draft IEPR).

## I. INTRODUCTION

The Draft IEPR correctly notes the "tradeoffs" that must be balanced across multiple objectives to achieve rapid electrification, electric supply decarbonization, reliable electric service, hardening the grid and adapting to increased wildfires from climate change, affordability, and equity.[2] The Draft IEPR identifies barriers to meeting these objectives in the context of

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1 California Community Choice Association represents the interests of 24 community choice electricity providers in California: Apple Valley Choice Energy, Ava Community Energy, Central Coast Community Energy, Clean Energy Alliance, Clean Power Alliance, CleanPowerSF, Desert Community Energy, Energy For Palmdale's Independent Choice, Lancaster Energy, Marin Clean Energy, Orange County Power Authority, Peninsula Clean Energy, Pico Rivera Innovative Municipal Energy, Pioneer Community Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Santa Barbara Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, and Valley Clean Energy.

2 *See* Draft IEPR, at 18-19 ("Electricity infrastructure must provide reliable service and be resilient to California's increasingly variable climate. Planners, regulators, and utilities must simultaneously balance investments in grid hardening and wildfire adaptation with expanding capacity to accommodate rapid growth in clean energy resources. At the same time, electricity must remain affordable, and the costs, benefits, and access to clean energy resources need to be more equitable. . . The critical challenge facing planners, regulators, systems operators, and utilities today is balancing tradeoffs between these objectives.").

connecting clean energy resources to the electricity grid, and recommends solutions to address the challenges related to the procurement needs, including: (1) adapting existing planning paradigms (including demand forecasting and electric grid planning) to accommodate the accelerated deployment of new resources; (2) efforts to better manage interconnection of new clean resources; (3) limiting burdens on ratepayers resulting from the deployment of new resources, and upgrading and hardening the grid; (4) increasing transparency of available transmission and distribution capacity for customers or project developers to connect to the grid; and (5) expanding public engagement and awareness campaigns to expedite permitting processes.[3] While all of these barriers are indeed relevant to the discussion related to challenges California is facing during the clean energy transition, the following additional items must also be incorporated into the IEPR to ensure a full picture is presented:

- The Commission should incorporate a discussion of Resource Adequacy (RA) market scarcity and high RA prices into the discussion of potential reliability and cost-effectiveness challenges;
- The Commission should emphasize the magnitude of the shift in clean energy policy goals over a short period of time and the implications for achieving accelerated deployment; and
- The Commission should provide more detail on approaches to limit the ratepayer burden for paying for climate initiatives.

[3] *See id.,* at 13-56 (Chapter 1 discussing speeding deployment and connection of clean resources to the grid).

## II. THE COMMISSION SHOULD INCORPORATE RESOURCE ADEQUACY ISSUES INTO THE IEPR ANALYSIS OF INTERRELATED GRID AND RELIABILITY CHALLENGES

### A. Challenges Resulting from Resource Adequacy Market Scarcity and High Prices Should Be Incorporated into the IEPR Reliability Analysis Along with Procurement Challenges

As discussed in CalCCA's Comments on the Scoping Order in this Docket (Scoping Order Comments),[4] the IEPR should not only address California's energy procurement challenges, but should also evaluate the reliability impacts of load-serving entities (LSEs) being challenged to meet their RA compliance obligations. As noted in the Scoping Order Comments, the California Public Utilities Commission (CPUC) is currently changing the methodology to compute minimum RA requirements by requiring LSEs to provide capacity for an entire month in all available hours.[5] While the peak need for RA is not greater than the IEPR's identified energy need, the RA will be required for all hours rather than just the peak hours.[6] Therefore resource owners will face a significantly greater obligation to meet an RA purchaser's needs than they would to sell energy at a single peak hour of the year.[7] As a result, meeting RA obligations is becoming increasingly difficult. Failure to procure sufficient resources to meet RA requirements results in LSEs facing substantial penalties through the CPUC program, ranging from $4.44/kilowatt (kW) month in the winter to as high as $26.64/kW-month in the summer.[8] A deficient entity can also face backstop costs from the California Independent System Operator (CAISO).[9]

4 *See* Docket No. 23-IEPR-01, *California Community Choice Association's Comments on the Scoping Order for the 2023 Integrated Energy Policy Report* (Sept. 18, 2023), at 3: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=23-IEPR-01.

5 Scoping Order Comments, at 3-4.

6 *Ibid.*

7 *Ibid.*

8 *Ibid.*

9 *Ibid.*

In addition to the increased obligations, the current RA market is extremely tight, as explained in the Scoping Order Comments and the CalCCA whitepaper on RA scarcity, entitled "California's Constrained Resource Adequacy Market: Ratepayers Left Standing in a Game of Musical Chairs."[10] CalCCA's whitepaper demonstrates that the available supply of RA exceeded the demand in September 2023 by a razor-thin margin of 540 megawatts (MW). This scarcity of supply results in the difficulty, if not the impossibility, of every LSE meeting its RA requirements. CalCCA estimates that the tight RA market conditions are likely to persist through 2026.[11] This RA supply deficiency prevents collective compliance by CAISO LSEs despite best efforts to procure and willingness to pay exorbitant prices.

As a result of the RA scarcity, serving California electricity customers has become more expensive. CalCCA's analysis demonstrates that the weighted average price for RA increased between September 2019 and September 2021 by over 100 percent from $4.08/kW-month to $8.62/kW-month.[12] CalCCA analysis of public capacity transaction data in the Federal Energy Regulatory Commission's (FERC's) Electronic Quarterly Reports (EQR) also shows that the weighted-average price for capacity delivered to the CAISO system continued to rise, exceeding $13/kW-month in 2023.[13] As noted in CalCCA's whitepaper, the lack of sufficient capacity available to meet RA needs is clearly driving up costs for California electricity customers. Since RA is the methodology to assure grid reliability, the IEPR should address the efficacy of the RA market and mechanism to ensure that California's electricity customers are provided with a reliable grid at affordable cost.

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10 The Scoping Order Comments discussed and attached the CalCCA RA Whitepaper dated September 15, 2023. CalCCA continually updates the data cited in the Whitepaper – attached hereto is the most recent version (dated December 1, 2023) of the Whitepaper.

11 CalCCA RA Whitepaper (Dec. 1, 2023), at 6.

12 Scoping Order Comments, at 7-8.

13 CalCCA RA Whitepaper (Dec. 1, 2023), at 9-10.

### B. IEPR Recommendations to Speed Deployment and Connection of Clean Resources Should Address Resource Adequacy Challenges and Include Potential Regulatory Solutions

RA scarcity and high RA prices raise significant reliability and cost-effectiveness concerns, and should be included among the "problems" identified in the IEPR that must be solved to meet California's energy goals. As noted in the Draft IEPR, market, legislative and regulatory process solutions should be considered to overcome the identified barriers.[14] While bringing new resources online over time will contribute to overcoming the RA scarcity challenge, CalCCA continues to encourage the CPUC to allow waivers for the system and flexible RA penalties upon a showing of good faith efforts by an LSE to procure the required RA. Such waivers could be considered on a case-by-case basis, with the burden of proof on the LSE to prove the efforts made to acquire the capacity. Given the shortages and difficulties LSEs are encountering in the market, such as developers missing deadlines from interconnection or supply chain issues, the LSEs should not be penalized when the reason for missing a RA requirement deadline is no fault of their own. If a waiver is granted, customers will benefit as the costs of the penalties will not trickle down to rates. Such a regulatory process change will not impact reliability, as LSEs will still be required to meet all RA obligations. However, the regulatory agencies can improve cost-effectiveness and affordability for ratepayers by allowing waivers in very limited circumstances. The IEPR should include the RA scarcity issue in its list of challenges, and provide potential recommendations and solutions to mitigate the impacts on ratepayers.

[14] *See* Draft 2023 IEPR, at 29 ("[t]he state's infrastructure planning and regulatory processes must now adapt to rapid load growth enabling beneficial electrification coupled with decarbonization of electricity supply. Keeping pace with market- and policy-driven clean resource deployment will require development of more proactive and flexible processes.").

## III. THE COMMISSION SHOULD EMPHASIZE THE MAGNITUDE OF THE SHIFT IN CLEAN ENERGY POLICY GOALS OVER A SHORT PERIOD AND THE IMPLICATIONS FOR ACHIEVING ACCELERATED DEPLOYMENT

CalCCA supports the Commission's identification of accelerated deployment straining the existing planning paradigms as a major barrier.[15] The Commission should also emphasize the role of rapidly changing policy goals in contributing to this strain. The CAISO 2021-2022 Transmission Plan[16] finds that the shift from Renewables Portfolio Standard (RPS) -related policies to aggressive 2030 greenhouse gas reduction goals set out by the California Air Resources Board (CARB), CPUC, and CEC in response to Senate Bill (SB) 100 requires significant investment in new transmission infrastructure.[17] Over four cycles of the transmission planning process, the planned rate of renewable deployment went from about 1 gigawatt (GW) /yr. in the 2019-2020 Transmission Plan, which focused on meeting 60 percent RPS goals,[18] to about 7 GWs/yr. in the 2022-2023 Transmission Plan, which focused on meeting SB 100 goals.[19] Over those same four planning cycles, the planned investment in new transmission increased from $0.14 billion[20] to $7.3 billion.[21] The increase in new transmission investment is even more significant when one considers that the 52 fold increase in transmission cost is not the complete set of transmission assets necessary to meet the SB 100 goals. The total cost of new transmission build will only be known as further transmission planning identifies and approves the necessary assets. The CAISO expects that the 45 transmission projects identified in the 2022-2023 plan

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15 *See* Draft IEPR, at 28-29.

16 CAISO 2021-2022 Transmission Plan. https://www.caiso.com/InitiativeDocuments/ISOBoardApproved-2021-2022TransmissionPlan.pdf.

17 *Id.*, at 15.

18 *See* CAISO 2019-2020 Transmission Plan. https://www.caiso.com/Documents/ISOBoardApproved-2019-2020TransmissionPlan.pdf, at 6.

19 *See* CAISO 2022-2023 Transmission Plan. https://www.caiso.com/InitiativeDocuments/ISO-Board-Approved-2022-2023-Transmission-Plan.pdf, at 16.

20 *See* CAISO 2019-2020 Transmission Plan, at 11.

21 *See* CAISO 2022-2023 Transmission Plan, at 3.

will be phased in with a lead time of eight to ten years.[22] Hence, the accelerated deployment is in response to changing policy goals and will take time and significant investment to build the necessary infrastructure.

## IV. THE COMMISSION SHOULD PROVIDE MORE DETAIL ON APPROACHES TO LIMIT THE RATEPAYER BURDEN FOR PAYING FOR CLIMATE INITIATIVES

CalCCA supports the Commission's recommendation to evaluate alternative sources for funding transmission and distribution system upgrades.[23] Initiatives to increase electrification to mitigate climate impacts will likely stall if ratepayers are burdened with all the up-front costs of transforming the grid. CalCCA suggests that the Commission provide more detail on how it will identify and evaluate strategies for reducing reliance on ratepayers to fund climate initiatives.

## V. CONCLUSION

CalCCA looks forward to further collaboration on this topic.

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel and Director of Policy
CALIFORNIA COMMUNITY CHOICE
ASSOCIATION

December 1, 2023

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22 *Id.,* at 4.

23 *See* Draft IEPR, at 46.

**ATTACHMENT**
**TO**
**CALIFORNIA COMMUNITY CHOICE ASSOCIATION'S COMMENTS ON THE DRAFT 2023 INTEGRATED ENERGY POLICY REPORT**

# CALIFORNIA'S CONSTRAINED RESOURCE ADEQUACY MARKET: RATEPAYERS LEFT STANDING IN A GAME OF MUSICAL CHAIRS

**(Updated December 1, 2023)**

# CALIFORNIA'S CONSTRAINED RESOURCE ADEQUACY MARKET: RATEPAYERS LEFT STANDING IN A GAME OF MUSICAL CHAIRS

**Updated December 1, 2023**

## 1. Introduction

The Resource Adequacy (RA) supply available within the California Independent System Operator (CAISO) balancing area for 2023 appears to have been inadequate to meet the RA program compliance requirements, depending on the availability of RA imports. The "stack" analysis in Figure 1 below, which compares RA requirements with the available RA supply, demonstrates that the margin was razor thin "on paper."[1] The Joint Agency Reliability Planning Assessment by the California Energy Commission (CEC) and California Public Utilities Commission (CPUC), which is based on an hourly analysis of anticipated supply and projected demand, roughly substantiates this conclusion. When the stack analysis is viewed in the context of regulatory dynamics and Western market constraints, the razor-thin margin becomes a material supply deficiency.

A wide range of factors have contributed to these conditions:

- Weather conditions are more extreme, increasing load and reducing generation output.
- Hydro resource availability has declined under drought conditions.
- New resources are delayed due to permitting, interconnection, and supply chain challenges.
- The entire Western region is constrained, reducing the availability of imports to California[2] and risking increased exports of California resources to meet other Western region requirements (*e.g.,* Western Resource Adequacy Program (WRAP)).
- CPUC reduction in effective load carrying capacity values reduced reliance on wind and solar resources to meet RA requirements.
- CPUC's increase in planning margins (PRMs) to 16 percent, with a 20-22.5 percent "effective" PRM for investor-owned utilities (IOUs), increased RA requirements.

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[1] The stack analysis focuses on the sufficiency of supply to enable load-serving entities to comply with RA program requirements and does not analyze the sufficiency of energy to meet Summer 2023 needs.

[2] Historical RA import data from the CAISO demonstrates that the amount of imports in year-ahead RA showings declined from 5,900 MW in 2020 to 3,600 MW in 2022. RA imports from unspecified resources declined from 4,300 MW to 1,300 MW over the same period. Historical year-ahead RA data: http://www.caiso.com/Documents/HistoricalYearAheadResourceAdequacyAggregateData.xlsx. Year-ahead RA showings for 2024 show 4,900 MW of RA imports, indicating a recovery from the 2022 lows, but still substantially below 2020 levels. The CAISO has not yet published updated information for year-ahead RA imports for 2023. Import Capability Used in RA Plan Data downloaded from oasis.caiso.com.

- CPUC's definition of "incremental" procurement to meet the effective PRM encouraged IOUs to cannibalize the existing RA resource stack, reducing supply for other LSEs.
- Unnecessarily restrictive requirements for energy imports under the CPUC's RA program reduced the availability of imports to the CPUC-jurisdictional RA market.

The RA supply deficiency likely prevented collective compliance by CAISO load-serving entities (LSEs) despite their best efforts to procure and willingness to pay exorbitant prices. Some LSEs subject to the CPUC's RA program were unable to obtain enough supply to comply with their year-ahead RA compliance requirements despite numerous formal solicitations and substantial bilateral outreach. Recent experience suggests the problem will only grow in the month-ahead RA compliance process absent a substantial increase in hydro output, imports, or expedited deployment of new resources.

Not all LSEs start the game with the same odds. IOUs hold most "legacy" supplies built prior to the recent growth of community choice aggregation (CCA) and the expansion of Direct Access (DA). As CCA or DA load has departed the IOU portfolio, the IOUs have retained for their remaining bundled load the supply previously procured for the departed load. Consequently, as conditions have changed, the burden of finding new supply to meet requirements has shifted largely to CCA and DA customers. The challenges in getting new steel in the ground thus have had a graver effect on these customers.

Under these conditions, RA program compliance has become a game of musical chairs: some chairs are occupied by the IOUs and some have been grabbed by out-of-state entities, leaving some California LSEs without a chair when the music stops. Until more new resources come online, the race to find a chair in the game will have detrimental consequences for all consumers. The RA shortfall has driven up prices paid by consumers. Prices for resources averaged $3.63 kilowatt (kW)-month in 2019;[3] summer 2023 has seen individual transactions at prices over $60 kW-month – the highest for CCAs being $82.94/kW-month – and resources are increasingly unavailable at any price. Sellers are the only market participants who benefit from this pressure.

RA penalties for LSEs unable to secure supply in a deficient market do nothing to get new resources in the ground; they unnecessarily add to customer costs and indirectly increase the cost of supply. Resource development is properly addressed in the CPUC's Integrated Resource Planning process and procurement mandates.

## 2. RA Supply/Demand Balance: 2023 RA Stack Analysis

The RA stack analysis in Figure 1 below compares the demand for system RA for peak months in 2023 to the total supply of RA, including RA from resources in the CAISO footprint and estimated

3 *2019 Resource Adequacy Report*, March 2021: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2019rareport-1.pdf, at 22.

RA imports.[4] RA supply is primarily derived from the CPUC's net qualifying capacity list, while RA demand is the forecasted median load in the CAISO plus a planning reserve margin.

As shown in Figure 1 below, the available supply of RA exceeded demand for RA by a razor-thin margin of 514 megawatts (MW), even after accounting for expected RA imports, in September 2023. Supply was similarly scarce to meet RA demand in August 2023. The scarcity of supply made it difficult, if not impossible, for every LSE to meet its RA requirements.

**Figure 1**

| | | Jun | Jul | Aug | Sep |
|---|---|---|---|---|---|
| 1 | CAISO 1-in-2 Load | 42,354 | 45,510 | 46,074 | 46,829 |
| 2 | Reserve Margin (16%) | 6,777 | 7,282 | 7,372 | 7,493 |
| **3** | **Total RA Demand** | **49,131** | **52,792** | **53,446** | **54,322** |
| 4 | 2023 NQC List | 48,669 | 49,420 | 49,148 | 49,526 |
| 5 | Event-Based Demand Response | 995 | 1,045 | 1,077 | 1,090 |
| 6 | Imports | 6,000 | 6,000 | 6,000 | 6,000 |
| 7 | Thermal Plant Derate | (718) | (718) | (718) | (718) |
| 8 | Excess IOU Resources In IOU Supply Plans | (1,266) | (507) | (396) | (443) |
| 9 | Retention for Substitution | (619) | (619) | (619) | (619) |
| **10** | **Total RA Supply** | **53,060** | **54,621** | **54,491** | **54,836** |
| 11 | Surplus Supply (Deficit) | 3,929 | 1,829 | 1,045 | 514 |

### 3. Sources and Explanation of the RA Stack

Figure 1 uses both familiar data in assessing RA supply sufficiency and also integrates information not typically considered in a supply analysis. This information, reflected in rows 8 and 9, stems from regulatory changes implemented by the CPUC that had the effect of eroding supply available to other LSEs. The table below documents the sources of data used in Figure 1.

| Row(s) | Source |
|---|---|
| 1 | CAISO 1-in-2 Load Forecast. Monthly peak demand forecast for a median (1-in-2) weather year from the CEC's 2022 Integrated Energy Policy Report Planning scenario.[5] |
| 2 | Planning Reserve Margin per CPUC D.22-06-050.[6] |

4 The data for Figure 1 are current as of December 1, 2023. The CAISO has not yet published updated information for imports for 2023, and therefore the import amounts have been estimated based on historical imports. *See infra at* 4, Table row 6.

5 Monthly maximum managed net load forecast for 2023 from the California Energy Demand 2022 Hourly Forecast for CAISO in the Planning Scenario: https://efiling.energy.ca.gov/GetDocument.aspx?tn=248359&DocumentContentId=82768.

6 D.22-06-050, Decision Adopting Local Capacity Obligations For 2023 - 2025, Flexible Capacity Obligations For 2023, and Reform Track Framework, R.21-10-002 (June 23, 2022): https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M488/K540/488540633.PDF.

| Row(s) | Source |
|---|---|
| 4 | CPUC 2023 NQC List. The CPUC lists the net qualifying capacity (NQC) for all resources in the CAISO footprint for 2023.[7] CalCCA exclude from the list all resources with a commercial online date later than one month before the applicable RA month. CalCCA found the commercial online date by matching the resource identification number (resource ID) in the NQC list to the resource ID in the CAISO Master Generating List.[8] |
| 5 | Event-Based Demand Response. Demand response quantities are from the CPUC's Resource Adequacy Compliance Materials.[9] Demand response totals include avoided losses and are from event-based programs at PG&E, SCE, and SDG&E. |
| 6 | Imports. Imports reflect the CEC's assumed RA imports available to the CAISO market.[10] These imports exceed the year-ahead showing of RA imports by 2,400 MW compared to the 2022 showing and 1,100 MW compared to the 2024 showing. |
| 7 | Thermal Plant Derate. Many thermal generators cannot produce maximum output at certain temperatures, leading to plant derates. For this reason, resource owners may not sell their full NQC as RA capacity. For thermal plants whose NQC is listed as equivalent to their Net Dependable Capacity, we apply a technology-specific thermal derate estimated from historical ambient temperature derates within the CAISO.[11] CalCCA's approach parallels recent CPUC discussions regarding the need to include thermal derates in reliability modeling.[12] |
| 8 | D.21-12-015 allowed: "excess resources from an IOU's *existing* portfolios may be used to meet or supplement these procurement targets up to the upper end of its contingency procurement target."[13] D.21-12-015 also authorized the IOUs to "continue their procurement efforts and endeavor to meet and exceed their respective incremental procurement targets to achieve the range of additional procurement authorized in this decision for months of concern… As noted previously, a combination of RA eligible and non-eligible resources will be used to meet the contingency procurement target range."[14] While these resources were |

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7 2023 NQC List for CPUC Compliance (October 17, 2023 version): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/cpuc-final-net-qualifying-capacity-report-for-compliance-year-2023-17oct23.xlsx

8 CAISO Master Control Area Generating Capability List: oasis.caiso.com.

9 2023-2025 Demand Response Totals: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

10 Joint Reliability Planning Assessment - SB 846 Second Quarterly Report, at Table 4: https://efiling.energy.ca.gov/GetDocument.aspx?tn=250176&DocumentContentId=84899. The CEC's assumed imports increased from 5,500 MW in the February 2023 assessment to the May 2023 assessment based on agency staff assessments of market conditions.

11 Ambient derate data can be found in the CAISO's daily Curtailed and Non-Operational Generator Prior Trade Date Reports: http://www.caiso.com/market/Pages/OutageManagement/CurtailedandNonOperationalGenerators.aspx.

12 ED Staff Proposal for Derating Thermal Power Plants based on Ambient Temperature: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/r21-10-002/4_ed-proposal-for-phase-3-derates.pdf.

13 D.21-12-015, Phase 2 Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2022 and 2023, R.20-11-003 (Dec. 2, 2021), at 103: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M428/K821/428821475.PDF. .

14 *Id.* at 101-102.

| Row(s) | Source |
|---|---|
| | intended to be incremental to supply available to LSEs to meet their 16 percent requirement, a significant amount appears to erode existing supply.[15] This erosion occurs because many of the resources are qualified to provide RA and, were it not for the IOU procurement, could provide RA to other LSEs to meet their RA compliance requirements. Line 8 represents the subset of the resources shown on the three IOUs' supply plan as filed in the IOU 2023 Excess Resources Report.[16] |
| 9 | Retention for substitution. IOUs are entitled to retain RA beyond their bundled needs for substitution during planned outages. While 2022 data are not yet available, this assessment relies on the 2021 resources retained by IOUs as reported in the 2021 IOU Excess Resource reports.[17] |

### 4. Tight Conditions Are Likely to Persist Through 2026

Extending the RA stack for September through 2026, Figure 2 below shows that the tight market conditions continue. The challenge of meeting RA requirements is exacerbated by rising load, increasing planning reserve margins, and retirement or removal from the RA market of resources like Diablo Canyon Power Plant (DCPP) and several once-through cooling plants. Deployment of new capacity to meet the CPUC's procurement requirements helps, though projects are likely to be delayed at least in the next few years. Though not reflected here, the RA market will undergo a fundamental shift in design, changing to a 24-hour slice of day approach starting in 2025.[18]

The sources and assumptions in this extended stack analysis are similar to the 2023 stack in Figure 1, with the following exceptions:

- The planning reserve margins for 2024-2026 increase to 17 percent;[19]
- In line with the assumptions of the Joint Agency Reliability Planning Assessment, described in the next section, DCPP is retired in 2025 and the remaining once-through-cooling plants are assumed to be procured by DWR;[20]

[15] The additional resources procured under this authorization are described in the CPUC's RA materials with additional detailed provided in advice letters filed by the IOUs. 2022 IOU Excess Resource reports: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

[16] Excess Resources Reports from https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

[17] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.

[18] D.22-06-050 at 128.

[19] *Id.* at 125 (requiring a 17 percent PRM for 2024, we assume the same for 2025-26).

[20] The capacity of once-through-cooling plants at risk of retirement is based on the CAISO's Announced Retirement and Mothball List: http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx.

- Excess IOU procurement for a higher effective PRM continues through 2025;[21] and
- For the years 2024 through 2026, the NQC List is based on the 2024 NQC list, though limited to resources built by the beginning of 2023.[22] Expected contracts for new-build resources are added to the list of resources. September new resources build is based on resources online by the end of Q2 in each year.[23]

**Figure 2**

| | September NQC | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|
| 1 | CAISO 1-in-2 Load | 46,829 | 47,475 | 47,987 | 48,487 |
| 2 | Reserve Margin (16% in '23, 17% after) | 7,493 | 8,071 | 8,158 | 8,243 |
| 3 | **Total RA Demand** | **54,322** | **55,546** | **56,145** | **56,730** |
| 4 | NQC List | 49,526 | 46,227 | 46,227 | 46,227 |
| 5 | Event-Based Demand Response | 1,090 | 980 | 955 | 978 |
| 6 | Imports | 6,000 | 6,000 | 6,000 | 6,000 |
| 7 | Estimate of Contracted Resources | - | 7,366 | 9,806 | 10,126 |
| 8 | Thermal Derates from 2023 NQC List | (718) | (723) | (723) | (723) |
| 9 | Remove Diablo from Planning | - | - | (2,280) | (2,280) |
| 10 | OTC, Retired or Contracted by DWR | - | (2,859) | (2,859) | (2,859) |
| 11 | Excess IOU Procurement for Higher Effective PRM | (443) | (1,700) | (1,700) | - |
| 12 | Retention for Substitution | (619) | (619) | (619) | (619) |
| 13 | **Total RA Supply** | **54,836** | **54,672** | **54,807** | **56,850** |
| 14 | Surplus Supply (Deficit) [Assuming Loss of Diablo] | 514 | (874) | (1,338) | 120 |

## 5. Results Generally Align with Joint Agency Reliability Assessment.

The Joint Agency Reliability Planning Assessment, issued on February 9, 2023, assessed hourly supply sufficiency across each year between 2023-2032. Here we focus on the Joint Agency results during critical hours in the month of September 2023-2026 using their assumption that new resources are based on ordered procurement with a delay rate of 40 percent. This assessment differs from the CalCCA assessment above because it focuses on hourly supply sufficiency, rather than RA sufficiency for compliance purposes. Consequently, the Joint Agency assessment:

- Projects a lower completion of new resources for September 2023 than actually observed (1,750 MW vs. 1,905 MW);

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21 Excess procurement of 1,700 MW for 2024 and 2025 is pursuant to a proposed decision in R.21-10-002, representing the minimum targeted procurement defined by the CPUC. IOUs would be authorized to procure as much as 3,200 MW for those same years, potentially increasing the deficits shown in Figure 2.

22 2024 NQC List for CPUC Compliance (November 16, 2023 version): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/cpuc-finalnetqualifyingcapacityreportforcomplianceyear2024-16nov23.xlsx

23 Expected contracted resources from the Joint Reliability Planning Assessment - SB 846 Third Quarterly Report, Table 2: https://efiling.energy.ca.gov/GetDocument.aspx?tn=251991

- Uses hourly production of wind and solar on peak demand days, resulting in a contribution of 1,819 MW from wind and solar to meeting demand in Hour 19 of September, compared to the 2,323 MW of wind and solar NQC in the RA stack;
- Uses earlier data for the 2023 NQC list and assumptions for imports (5,500 MW vs. the more recent 6,000 MW assumption);
- Uses demand response estimates that may include programs that are not typically used to meet RA requirements;
- Assumes the full contribution of thermal plants are available each hour without accounting for ambient thermal derates associated with high temperatures;
- Does not need to consider the effect of the IOUs' retention of capacity for substitution, since those resources will be available supply unless they are actually substituted for a resource on outage;
- Does not need to consider the effect of the IOUs' incremental "effective" PRM procurement; although the supply may not be available to LSEs to meet their RA requirements, the resources will be a part of the actual supply.

Despite these differences, which tend to present a more positive view of supply, the assessment shows a very tight supply margin, for Hour 19 in September 2023 – arguably the most challenging hour to meet. The Joint Agency assessment is summarized below in Figure 3, which was prepared by CalCCA using Joint Agency data.[24]

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[24] CalCCA created the table from the underlying data used in the Joint Reliability Planning Assessment (https://efiling.energy.ca.gov/GetDocument.aspx?tn=248714&DocumentContentId=83233 consistent with a conversation with CEC staff on Jan. 31, 2023.

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**Figure 3**

| | Hour 19 Assessment in the Month of September | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|
| 1 | CAISO 1-in-2 Load | 46,827 | 47,472 | 47,933 | 48,424 |
| 2 | Reserve Margin (16% in '23, 17% after) | 7,492 | 8,070 | 8,149 | 8,232 |
| **3** | **Total Hourly Demand** | **54,319** | **55,542** | **56,082** | **56,656** |
| 4 | Existing Resources Except Wind and Solar | 44,817 | 44,817 | 44,817 | 44,817 |
| 5 | Supply from Wind | 1,810 | 1,810 | 1,810 | 1,810 |
| 6 | Supply from Solar | 9 | 9 | 9 | 9 |
| 7 | Estimated Completion of CPUC Mandated Procurement | 1,750 | 6,431 | 10,381 | 11,755 |
| 8 | Demand Response | 1,274 | 1,274 | 1,274 | 1,274 |
| 9 | Imports | 5,500 | 5,500 | 5,500 | 5,500 |
| 10 | Remove Diablo from Planning | - | - | (2,280) | (2,280) |
| 11 | OTC, Retired or Contracted by DWR | - | (3,757) | (3,757) | (3,757) |
| **12** | **Total Hourly Supply** | **55,159** | **56,084** | **57,753** | **59,128** |
| 13 | Surplus Supply (Deficit) | 840 | 542 | 1,672 | 2,472 |
| 14 | Incremental Demand with 2020 Equivalent Event | 3,044 | 2,611 | 2,636 | 2,663 |
| 15 | Add'l. Incremental Demand with 2022 Equivalent Event | 1,639 | 1,662 | 1,678 | 1,695 |
| 16 | Surplus Supply (Deficit) with Extreme Weather | (3,843) | (3,731) | (2,642) | (1,887) |

## 6. The Impact of Weather on Capacity

The changes in precipitation levels from 2022 to 2023 have been an extreme that helps to demonstrate the impact of weather on capacity. As of June 14, 2023, the California Department of Water Resources (CDWR) reports that the water content of snowpack for the State is at 333 percent of normal.[25] On the same day in 2022, CDWR reported that the snowpack had already melted leaving the state at zero percent of normal. In addition to the snowpack, rain has helped to fill reservoirs prior to the snow melt placing many of California's reservoirs above their historical average as early as March.[26]

Using data from the CEC from the past 20 years, 2006 had the highest amount of energy production from hydroelectric generating facilities at 48,559 gigawatt hours (GWh). This high was reached on installed capacity of 13,557 MW of large and small hydro in California at the time for a capacity factor of 40.9 percent. This compares with 2022 where the CEC shows energy generation of 17,612 GWh from an installed capacity of 14,035 MW for a capacity factor of 14.3 percent.[27] Simply put, more water yields more energy. Since the amount of installed capacity in 2023 from large and small hydro is at least as much as it was in 2006, given the amount of available water, it is reasonable to expect that the energy production in 2023 was similar to that in 2006.

[25] https://cdec.water.ca.gov/snowapp/sweq.action.
[26] https://cdec.water.ca.gov/reportapp/javareports?name=STORSUM.202303.
[27] https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy.

The RA program counts capacity from resources based on their capability of providing that level of output in a sufficient number of hours to meet system load needs. The RA program will therefore derate the amount of capacity from hydroelectric facilities to account for water available for use at the facility. In 2022, this amount was at historic lows. In fact, the process for RA had the Year-Ahead showing for 2023 occurring in October 2022. At that point in time, CDWR reported snow-pack levels at zero percent of normal. Without knowing that the 2022-2023 precipitation season would be as good as it turned out, the amount of hydroelectric generation for RA was likely assumed to be at very low levels for the Year-Ahead showing process. These expectations likely had a significant effect on the amount of hydro output offered as RA in the Year-Ahead process.

This issue does not only impact California. Hydroelectric generation is prevalent in the Pacific Northwest and there are significant quantities in the Southwest as well. With uncertainty surrounding the amount of precipitation that either of those areas would receive, entities were unwilling to sell significant amounts of import capacity for the Year-Ahead process.

With conditions better known in June, significant amounts of hydroelectric generation in and out of state were likely available, easing the tight capacity market. High hydro conditions were good news for 2023 for California's Month-Ahead RA process but did nothing to cure the lack of capacity for the already complete Year-Ahead RA process. Importantly, it further has little bearing on what the hydroelectric conditions will bring for 2024 onward.

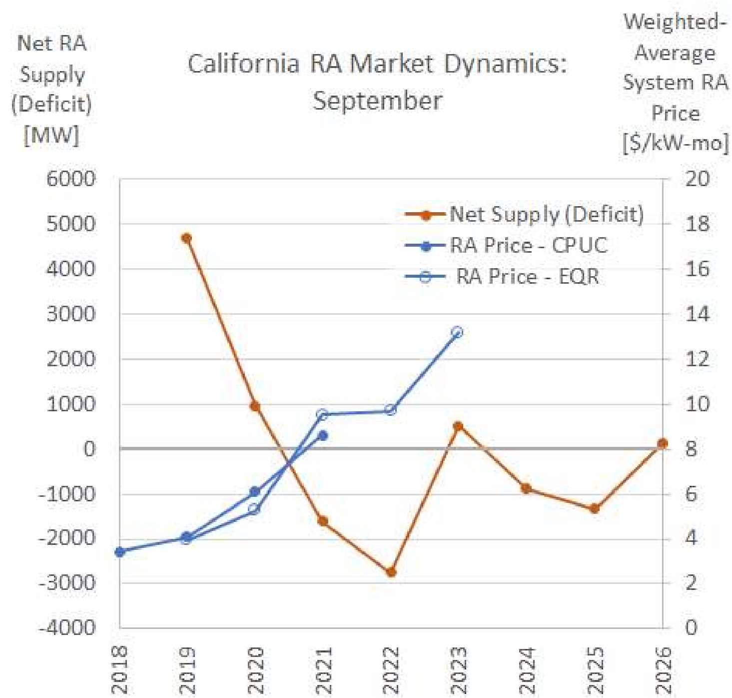
## 7. The Shortage of RA has Capacity Prices at All Time Highs

As basic economics would predict, these conditions are ripe to produce exorbitant prices, making reliably serving California's electricity customers more expensive. Between September 2019 and September 2021, the net RA supply decreased by 6 GW[28] while the weighted average price for September RA increased by over 100 percent from \$4.08/kW-month to \$8.62/kW-month (see Figure 4 below).[29] CalCCA analysis of public capacity transaction data in FERC Electronic Quarterly Reports (EQR) shows that the weighted-average price for capacity delivered to the CAISO system continued to rise to over \$13/kW-month in 2023.

[28] CalCCA estimated the net RA supply in September for 2019-2022 using assumptions similar to the 2023 RA Stack in Section 3. Key differences include the use of a 15 percent PRM, load forecasts from the CED 2019 and CED 2021, NQC lists from the relevant year, event-based demand response from the relevant year, historical import RA from the relevant year, and no excess IOU procurement for higher effective PRM.

[29] 2021 Resource Adequacy Report (Apr. 2023), at 29: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2021_ra_report_040523.pdf.

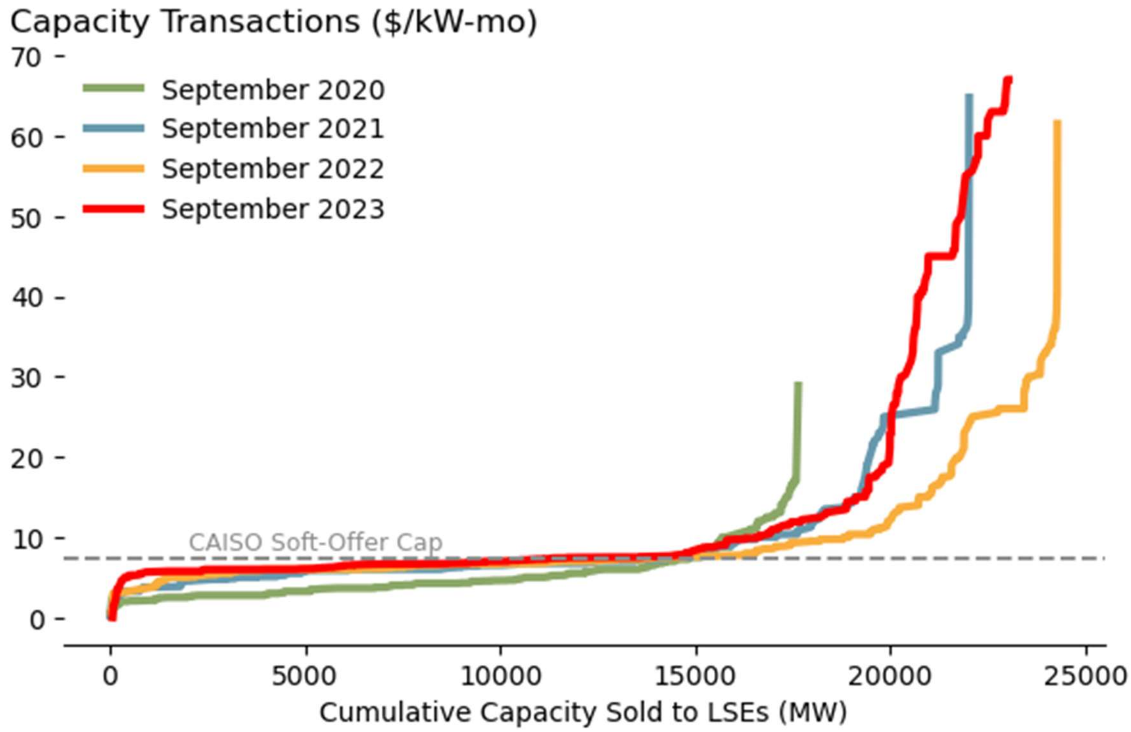
**Figure 4**




Importantly, detailed transaction level data from the FERC EQRs shows that the rise in average capacity prices is primarily driven by a growing share of transactions at extremely high prices (See Figure 5, below). In September 2020, a time with excess RA supply, around 2,800 MW of RA capacity was purchased by California LSE's at prices above $7.34/kW-mo, the CAISO's recently proposed soft-offer cap for the capacity procurement mechanism (CPM).[30] In contrast, more than 7,800 MW, 10,600 MW, and 11,700 MW were purchased at prices above $7.34/kW-month in September 2021, 2022, and 2023 respectively, times with an RA deficit or extremely tight market. The highest observed prices rose from $17/kW-mo in September 2020 to over $60/kW-mo in September 2021, 2022, and 2023. LSE's faced with a responsibility to meet their RA obligation at any cost are being met with generators only willing to sell at prices five to eight times higher than the CAISO soft-offer cap. The lack of sufficient capacity available to meet RA needs is clearly driving up costs for California electricity customers.

[30] *Capacity Procurement Mechanism Enhancements*, Track 2 Straw Proposal (June 30, 2023): http://www.caiso.com/InitiativeDocuments/StrawProposal-CapacityProcurementMechanismEnhancements-Track2.pdf.

**Figure 5**




## 8. Tight Market Conditions Across the West Limit Availability of RA Imports

The ability of California LSEs to meet their RA obligations in 2023 into future years depends on the availability of RA imports from the rest of the West. Across the West, resource adequacy has become a priority issue as regions experience load growth, retire aging coal plants, and turn to resources like solar for future needs. Demonstrating the importance of RA, utilities across the West supported the development of the Western Resource Adequacy Program (WRAP) as a mechanism to formalize resource counting and to share excess resources when needed in the operational timeframe.[31] Currently, however, no entity regularly quantifies the excess supply of RA in the West that is available for California LSEs to rely on for imports.

We use public reliability assessment data, primarily from the North American Electric Reliability Corporation (NERC), to provide visibility into trends in the availability of RA resources outside of California. We consider both historical data and projections to evaluate the potential implications for California RA markets.

The availability of resources to import into California depends on whether other sub-regions of the Western Electricity Coordinating Council (WECC) have generating capacity that exceeds their peak demand and planning reserve margins. NERC summer reliability assessments (released in May of each year) provide prompt year peak load forecasts and on-peak resource

[31] WRAP: https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

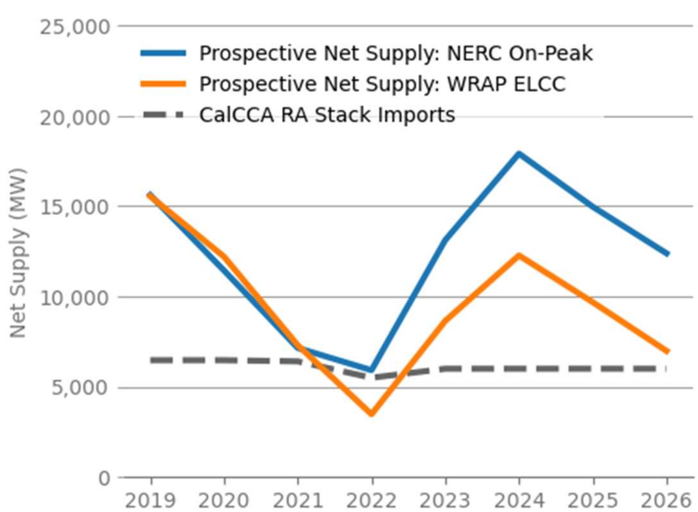
totals for each WECC sub-region. NERC's long-term reliability assessments (released in December each year) provide ten-year projections of loads and resources.

We assume that the resources available to California as RA imports can be calculated as the net supply aggregated across all the non-California WECC sub-regions, where net supply is the amount that the prospective on-peak resource capacity exceeds the peak demand forecast plus a planning reserve needed to meet the Reference Reserve Margin. Due to several limitations in the data and methodology, this net supply calculation is not an exact assessment of available imports, instead it is a proxy whose value over time should reflect trends in the true import availability over the same time horizon. The limitations of this approach include:

- NERC reports non-coincident peaks across WECC sub-regions, meaning that the reported peaks are not expected to be reached at the same time;
- Aggregating resources and demand across all of the WECC sub-region ignores inter-region transmission limits and overstates the availability of supply;
- The approach treats the Reference Reserve Margin as a level of planning reserves that must be met prior to exporting; in reality, California is unique in specifying a mandated planning reserve margin.

Another limitation of the NERC data is that it reports contributions of prospective resources based on their on-peak production. It is apparent in California, that as the share of solar grows, production during the net peak rather than gross peak becomes a more reasonable assessment of the reliability contribution of solar. The WRAP assesses reliability contributions of wind and solar based on effective load carrying capability (ELCC) studies that account for the shifting periods of greatest reliability need. We calculate net supply using the NERC On-peak values and the proposed ELCC values for wind and solar from the WRAP program, based on values applicable to August.

**Figure 6**



Across the non-CA WECC, the prospective net supply is positive in all years between 2019 and 2026, suggesting RA resources are available to import into California. The size of available resources, however, appears to change dramatically across years, Figure 6. A 15 GW surplus in resources fell to only 4-6 GW by 2022 because of an increase in load between 2019 and 2020 and a decrease in generation capacity from 2020 to 2022, largely associated with coal plant retirements. The RA imports in the CalCCA RA stack closely tracks the prospective net supply in the Non-CA WECC, suggesting that nearly all of the available resources were imported into California.

New resources were added after 2022 and additions are expected to continue through 2024 at a rate that exceeds load growth, reducing the tightness in the non-CA WECC region and again freeing up resources to import into California. The major source of new capacity between 2022 and 2024 is solar with some growth in storage, geothermal, and hydropower.

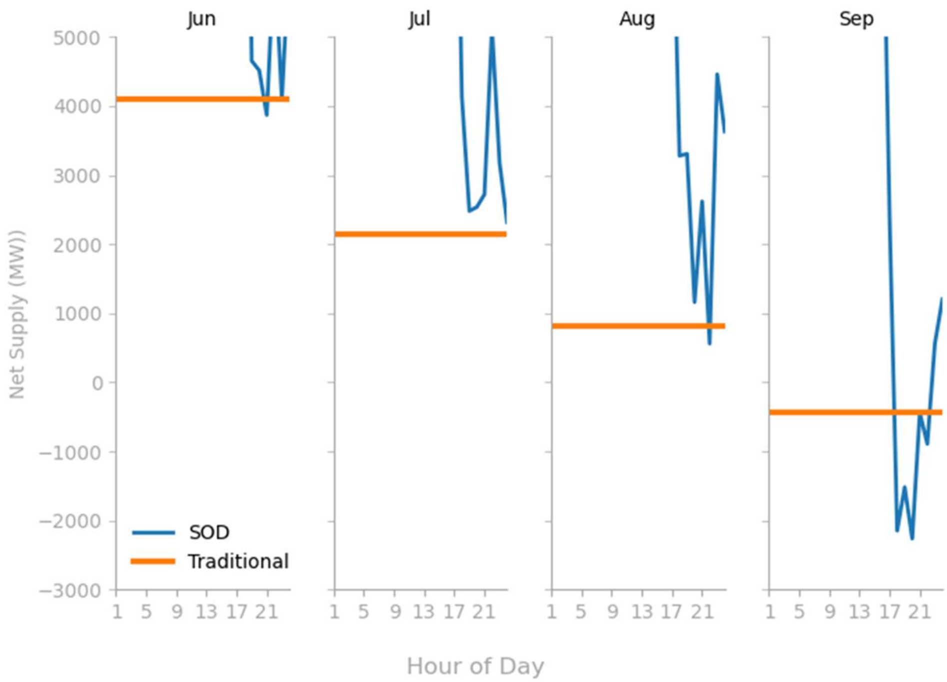
Whether the net supply surplus in the Non-CA WECC region returns to its 2019 levels depends on the capacity accreditation of solar. Using WRAP ELCC values for solar and wind capacity accreditation reduces the net supply surplus by 5.6 GW relative to the surplus calculated with NERC On-Peak values in 2024. The difference in net supply between the two methods continues to be about 5-6 GW through 2032. The lower net supply surplus with the WRAP ELCC values suggests that widespread participation of utilities in the WRAP program may mean that fewer resources are available to import into California.

## 9. The New CPUC Slice of Day RA Mechanism Will Not Address Thin Supply Margins

In the current Resource Adequacy framework, LSEs procure RA resources for each month of the year to meet their allotted share of the monthly peak demand and planning reserve margin. The contribution of a resource toward the RA obligation is based on its NQC, represented by a single value each month. Beginning in 2025, the Resource Adequacy framework will shift to a new “Slice-of-Day” framework in which the monthly RA obligation is defined for each of the 24 hours in a day and the contribution of a resource can similarly vary by hour of the day. To analyze the implications of this new framework CalCCA developed a “Slice of Day” RA stack analysis for 2023 using data and assumptions similar to the RA stack presented in Section 3. The results show that in critical months, the shift to the Slice-of-Day framework will further tighten the resource adequacy market, Figure 7.

The SOD framework will expose existing constraints currently masked by the annual-peak RA requirements measure. Many hours of the day have significant surplus supply, but not in early evening hours after sunset. In the early evening, the net supply in the SOD stack is at its lowest and, as shown in Figure 7, can be lower than the net supply calculated with the traditional RA stack for the same set of resources. Months in which the SOD net supply is lower than the traditional net supply will lead to a tighter RA market and greater challenges for LSEs to meet their RA obligations. For the resources and demand in the 2023 RA stack, the most challenging month was September in both the SOD and traditional approach, with hour ending 20 the most critical hour in September.

**Figure 7**




The differences between the Slice of Day stack and the traditional RA stack include:

- Demand: For SOD, demand is represented by the 24-hourly values on the day with the highest peak load of each month.[32] For the traditional stack, demand is the single highest peak load of each month. The 16 percent planning reserve margin is applied to all 24 hours in SOD and the highest load hour in the traditional stack.
- Wind and Solar: For SOD, the contribution of wind and solar varies by hour and is calculated from exceedance values with historical data.[33] For the traditional stack, the contribution of wind and solar is based on a monthly estimate of the effective load carrying capability (ELCC).
- Energy Storage: For SOD, the contribution of storage to any hour is constrained based on characteristics of the resource, including the power rating, the maximum sustained discharge energy, the maximum number of daily cycles, and the availability of excess capacity to charge the storage.[34] Within these capabilities storage is dispatched to

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32 Hourly managed net load forecast for 2023 from the California Energy Demand 2022 Hourly Forecast for CAISO in the Planning Scenario: https://efiling.energy.ca.gov/GetDocument.aspx?tn=248359&DocumentContentId=82768.

33 CPUC Master Resource Database version 3: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/resource-adequacy-history/mrd-draft-2.xlsx. The exceedance profiles for wind and solar vary by technology and location.

34 Ibid.

minimize any deficits in net supply, or if none exist, to flatten out the net supply.[35] For the traditional stack, the contribution of storage is based on its full nameplate capacity (or proportionally derated if the maximum discharge duration is less than 4 hours.).

- Imports: For the SOD, imports are assumed to be available between hour ending 7 and hour ending 22 following the common “6 X 16” contract schedule. In the traditional stack RA import estimates are based on estimated availability during early evening hours.

The primary reason why the SOD net supply in hour ending 20 is lower than the traditional net supply in September is differences in the contribution of solar. In the traditional RA stack, solar resources contribute up to 11 percent of their nameplate capacity toward the RA supply. In the SOD stack, on the other hand, the contribution of solar to supply in hour ending 20 is nearly zero based on the calculated exceedance values.

Design elements of the SOD framework may further exacerbate the challenges relative to the analysis presented above. In the above analysis, all sources of supply and all demand are pooled prior to calculation of the hourly net supply. In practice, the SOD framework will require that each LSE meet its 24-hour obligations only with resources in its portfolio. Unless there are changes to the proposed SOD framework, resources cannot be subdivided hourly to optimize the LSEs' portfolios. Depending on the composition of individual LSE portfolios and the 24-hour shape of their demand profile, the net supply from first pooling all loads and resources, as assumed in this stack, may be greater than the aggregate net supply without pooling, reflecting the constraints on individual LSE showings. Two examples illustrate this challenge:

- An LSE with a net surplus in one hour cannot allocate that surplus to another LSE with a deficit in the same hour unless they transfer all 24-hours of capability from the resource to the other LSE.
- The charging energy for storage must be met by surplus supply within an LSE’s own portfolio, any excess charging energy in another LSE’s portfolio is not transferable without trading all 24 hours of the capability of an excess resource.

Even achieving the net supply shown in this SOD stack may require modifications to the framework such as adding transactability of LSE load obligations or individual hours of a resource. Nevertheless, even with these enhancements the transition to the Slice of Day framework alone will not address the tight RA market conditions projected through 2026.

## 10. Challenges With New Resource Uncertainty

New resources bring new challenges. The RA program allows a new resource to count in the Year-Ahead process from the month of its expected on-line date. However, if the resource fails to reach commercial operation at that date, the resource may not be counted in the Month-Ahead process and the LSE must find a different resource to meet their RA needs. The challenge this presents is that an LSE is unlikely to sell any excess RA in the Year-Ahead process if that excess

[35] LSE’s can determine their planned storage dispatch. For this analysis, CalCCA developed a simple optimization model to determine the best way to charge and discharge storage.

is contingent on a new resource achieving commercial operation. Why sell off excess resources only to find the new resource did not come on-line and have to buy another resource at potentially a higher price than the excess was sold for? In addition, it is becoming relatively common for entities to offer sales of capacity contingent on the new resource achieving commercial operation. That is, a seller that is long capacity if the new resource comes online will sell the excess contingent on the resource achieving commercial operation and thus move the non-compliance risk to the buyer.

Much like the hydroelectric discussion in Section 6, the availability of new build expected to come on-line in a compliance year is likely more constrained than the Month-Ahead process when the commercial operation date is known. To the extent the resource has come on-line, the LSE is now willing to sell excess RA so that their customers get the value of the resource without a risk that it will make them non-compliant with their RA requirements.

The only way to ease the current capacity constraints of the RA market is to continue to build new resources. However, this new build is likely to ease constraints in the Month-Ahead RA market and not in the Year-Ahead market due to the uncertainty of achieving commercial operation from the resource.

## 11. Conclusion

The supply of resource adequacy left only a razor-thin margin to meet 2023 demand. The tightness in the market made it difficult, if not impossible, for all LSEs to comply with year-ahead requirements, and the tight conditions carried into month-ahead compliance. The only durable solution is to bring new resources online, yet new resources continue to face supply chain, interconnection, and permitting challenges. Until those challenges are met holistically, RA supply will remain tight and prices paid by consumers will remain high. In addition, the potential variability of RA supply between Year-Ahead and Month-Ahead RA showings creates a new issue that must be recognized in the RA program.

Seven interim actions should be considered.

1) Expressly recognize the tight RA supply conditions and its consequences in the CPUC's next RA decision.
2) Establish a "safety valve," through a discretionary waiver structure for LSEs left deficient in meeting their requirements despite best efforts, to prevent the exercise of market power by suppliers.
3) Consider the potential for waiving Year-Ahead penalties if an LSE meets its obligation in the Month-Ahead showing.
4) Increase the likelihood that California LSEs can secure imports for RA compliance by increasing the CPUC-imposed energy market bid cap on imports – currently set at $0/MWh -- to reduce sellers' risk of financial loss.
5) Prevent erosion of the supply stack available to LSEs to meet their RA requirements by limiting any IOU "effective PRM" procurement to truly incremental, non-RA resources.

6) Increase market transparency by providing aggregated compliance data to reveal (a) trends in the categories of resources (e.g., imports, storage) used for compliance and (b) the extent of California resource exports.

7) Test and evaluate the new Slice of Day RA model to ensure that:

   a. There are sufficient resources to be able to meet the new RA accounting mechanism. If there are not, then the Commission must examine what must be done to obtain a fleet capable of meeting the need before implementing penalties for RA deficiencies if the current fleet is incapable of meeting the reliability need.

   b. Evaluate the need for transactability adjustments in the Slice of Day mechanism. As discussed in Section 8, the ability to meet the requirements of the entire system from all resources is just the first step. While necessary, it is not sufficient to ensure effective compliance. To be sufficient, the Slice of Day mechanism must consider effective and efficient mechanism to enable parties to transact to meet individual compliance obligations which will also ensure that the total reliability need is met.