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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 23-10-011 (Filed October 12, 2023)

THE PROTECT OUR COMMUNITIES FOUNDATION OPENING COMMENTS ON PROPOSED DECISION ON TRACK 2 ISSUES

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Pursuant to Rules 14.3 of the Commission's Rules of Practice and Procedure[1] The Protect Our Communities Foundation (PCF) timely submits these opening comments on the Proposed Decision on Track 2 Issues (PD).[2]

I. INTRODUCTION

Track 2 of the Commission's Resource Adequacy proceeding, R.23-10-011, involves an assessment of the Planning Reserve Margin (PRM) as calculated in the loss of load expectation (LOLE) Study[3] and the subsequently issued LOLE Appendix,[4] which was issued to correct errors in the calculation of the PRM. Track 2 also addresses the central procurement entity framework (CPE) and whether and how to reform it, given the fluctuating and expensive costs from the Utilities purchasing backup procurement through the CPE process. The PD wisely recommends additional analysis of the assumptions and inputs used to calculate any changes to the current PRM. PCF agrees that additional analysis remains necessary and that the Commission

[1] Commission Rules of Practice and Procedure, Rule 14.3.
[2] R.23-10-011, Proposed Decision on Track 2 Issues (October 29, 2024).
[3] R.23-10-011, Loss of Load Expectation Study for 2026 Including Slice of Day Tool Analysis Recommendation for Slice of Day Planning Reserve Margin (July 19, 2024).
[4] R.23-10-011, Appendix A to Loss of Load Expectation Study for 2026: Revised Slice of Day Tool Analysis Appendix A to Loss of Load Expectation Study for 2026: Revised Slice of Day Tool Analysis (August 30, 2024), p. 3.

should not adopt any of the results produced to date because Energy Division's (ED) modeling generated inconsistent results that set the PRM much too high and generate unnecessary additional costs for ratepayers. The initial iterations of the Energy Division's modeling represent a significant and unnecessary escalation over previous results and their unwarranted modeling assumptions should be corrected, as PCF details below.

The PD notes myriad concerns about the lack of adequate resources and about local reliability pockets which may experience resource shortages. All the PD's concerns can be resolved if the PD was revised to require SERVM and RESOLVE modeling to include all existing behind-the-meter (BTM) solar and storage resources as available generation. BTM solar and storage constitute critical resources, but the Commission's models and analyses continue to fail to incorporate BTM solar and storage when assessing need and availability of generation resources. With California's rapidly escalating rates and the increasing importance of meeting greenhouse gas emissions goals, the Commission should prioritize BTM solar and storage by analyzing and including these resources in the same way that the Commission analyzes all other resources. PCF's Appendix details how the Commission should revise the PD to incorporate BTM solar resources into its resource modeling and analysis.

The PD should be revised to reject the Unforced Capacity (UCAP) proposal, because it does not consider whether resource owners and operators are following the management practices necessary to prevent outages. Further, the UCAP proposal cedes too much authority to the California Independent System Operator (CAISO) to provide data and analyze the causes of outages and the plant specific data needed to set an appropriate UCAP framework.

The PD should follow the CAISO's Department of Market Monitoring (DMM)'s warnings and authorize bids only at prices that reflect generators' actual costs to produce electricity. Incorporating opportunity costs into allowable bids implicitly approves the sellers' exercise of market power and results in exorbitant costs that will drive ratepayer bills even higher. Moreover, this summer's D.C. Circuit decision in *Shell Energy North America v. FERC* eliminates any basis to set a bid price at the CAISO's soft cap.

The PD correctly adopts proposals that will increase transparency, including eliminating the non-compensated self-showing option and expanding publication of CPE procurement information. Eliminating the non-compensated self-showing option will allow the CPE to make informed procurement decisions, while expanding the publication of CPE procurement information will grant more insight into the procurement process. The Commission should prioritize the assessment of additional areas where it can enhance pricing and procurement transparency in Track 3 of this proceeding.

II. THE PD APPROPRIATELY POSTPONES ADOPTING A PRM BECAUSE OF THE ANOMALOUS LOLE STUDY RESULTS THAT GENERATED AN EXCESSIVELY HIGH PRM.

The PD appropriately defers consideration of the PRM to Track 3 of this proceeding.[5] As the PD acknowledges, several concerns need to be corrected before the LOLE Study can be adopted by the Commission.

The Energy Division, in its LOLE Appendix, could not explain why February produced anomalously high results after stress testing. The modeling in the LOLE Appendix resulted in two PRM values, with the proposed larger PRM value unusually applied from January to May, [6] rather than setting a higher PRM for the typical summer peak months. The aberrant modeling results demonstrate that more work needs to be done before the LOLE Study is complete. Thus, the PD appropriately directs Energy Division to undertake additional analyses and does not adopt the Energy Division's proposal to increase the current PRM.[7]

PCF recommends that Energy Division staff should also correct the base case scenario assumptions to reflect reality. The PRM represents the percentage of resources above the base case scenario needed to meet a particular reliability standard (Energy Division used the 0.1 LOLE standard to calculate its PRM in the LOLE Study).[8]

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[5] PD, p. 11.
[6] R.23-10-011, Appendix A to Loss of Load Expectation Study for 2026: Revised Slice of Day Tool Analysis Appendix A to Loss of Load Expectation Study for 2026: Revised Slice of Day Tool Analysis (August 30, 2024), p. 9 ("Staff arrived at a levelized PRM that resulted in LOLE at 0.1 with a PRM of about 23.5% for the months of June to December and 26.5% for the months of January to May. Only February was unable to reach acceptable LOLE at that level and staff will continue to investigate February results further.").
[7] PD, p. 64 (COL 1).
[8] Loss of Load Expectation Study for 2026 Including Slice of Day Tool Analysis Recommendation for Slice of Day Planning Reserve Margin (July 19, 2024), p. 6 .

In the LOLE Study and the LOLE Appendix, ED staff artificially decreased the level of imports[9] below historical levels[10] because they deemed the base case scenario "over reliable."[11] However, if the base case scenario was already reliable, it is unclear why Energy Division needed to create a less reliable portfolio by lowering the import constraint, consequently artificially increasing the PRM. As a result of ED staff's addition of artificial constraints into its modeling, the model inaccurately concluded that more resources were required to meet the 0.1 LOLE standard, thereby increasing the PRM above what it should be if the base case portfolio had included all the existing available resources. Artificially reducing the base case scenario means that more resources will be required to meet the reliability standard, which increases the PRM unnecessarily and imposes unwarranted extra costs on ratepayers.

Not only were the results of the Appendix poorly explained, but the PRMs the modeling produced were also unusually high. The ED staff's proposed PRMs represent a significant increase from the current and prior PRMs adopted by the Commission.[12] As the Utilities warned, if the Commission adopts PRMs at the level recommended by Energy Division's incorrect modeling, the amount of required procurement would immediately increase, resulting in rapidly escalating rates.[13]

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[9] Loss of Load Expectation Study for 2026 Including Slice of Day Tool Analysis Recommendation for Slice of Day Planning Reserve Margin (July 19, 2024), p. 4 ("[S]taff confirmed that the model met the target reliability level of 1 day in 10 years (0.1 LOLE) using the updated Baseline set of resources and evening peak hours CAISO simultaneous imports constrained to 2,500 MW rather than the prior assumption of 4,000 MW.").

[10] CAISO, Today's Outlook, available at https://www.caiso.com/todays-outlook/supply (On Friday, September 6, 2024, a day of very high demand, imports were 4,180 MW at 7 PM, when the supply of solar resources were no longer available; On Friday, August 14, 2020, the first day of the 2020 blackouts, imports were 4,000 MW or higher through the 4 pm – 9 pm on peak hours).

[11] Loss of Load Expectation Study for 2026 Including Slice of Day Tool Analysis Recommendation for Slice of Day Planning Reserve Margin (July 19, 2024), p. 7 ("Focusing on the peak month only, staff found that the baseline resource fleet was over reliable, allowing for a decrease in the evening CAISO simultaneous import constraint from 4,000 MW to 1,700 MW.").

[12] D.23-06-029, Decision Adopting Local Capacity Obligations For 2024 - 2026, Flexible Capacity Obligations For 2024, And Program Refinements (July 5, 2023) p. 133 (COL 5) (A PRM of 17 percent is reasonable and prudent for the 2024 and 2025 RA years.); D.04-01-050, Interim Opinion, p. 193 (January 26, 2004), Conclusions of Law 5, ("Based on the record developed in this proceeding, we should reaffirm and make permanent the 15% reserve level, as well as allow for a range up to 17% to account for the lumpiness of investment.").

[13] R.23-10-011, Opening Comments Of San Diego Gas & Electric Company (U 902 E) On Lole Study And Calibration Tool (September 9, 2024). p. 1 ("[A] higher PRM … will likely have downstream impacts that result in increasing costs for SDG&E's customers."); R.23-10-011, Southern California

Adopting the PRMs that Energy Division's modeling proposes would also set California's required procurement at PRM levels that far exceed every other area of the country.[14]

The PD should also be revised to order the Commission in Track 3 to evaluate the 0.1 loss of load hours (LOLH) standard, rather than the LOLE standard. The 0.1 LOLE standard represent one loss of load day every ten years, whereas the LOLH standard represents the average number of shortfall hours per year.[15] While there are different definitions of what the 0.1 LOLH standard is, the Commission should consider CEJA's and Sierra Club's recommendation to define the 0.1 LOLH standard as an average of 2.4 hours per year as a way to maintain reliability but not require excess procurement, instead of adopting the 0.1 LOLE.[16] The 0.1 LOLE standard, which the PD proposes to adopt, will likely raise costs as compared to the 0.1 LOLH standard, because the stricter 0.1 LOLE standard requires more procurement to meet the standard.[17] The Commission must also take into account the rapidly escalating costs imposed on ratepayers, and the PD should be revised to adopt a standard that would lead to lower costs while maintaining sufficient reliability. Thus, the PD should be revised to consider a 0.1 LOLH standard in Track 3.

III. THE PD SHOULD INCORPORATE BTM SOLAR AND STORAGE INTO ALL MODELS AND THE LOAD IMPACT PROTOCOLS.

The PD should be revised to incorporate BTM solar and storage into Energy Division's RESOLVE and SERVM models and the Load Impact Protocols.

Edison Company's (U 338-E) Opening Comments On Administrative Law Judge's Ruling On Revised Slice Of Day Calibration Tool And Comment Schedule (September 9, 2024) ("If the Commission adopts the Energy Division's recommended PRMs … all LSEs will be forced to over procure resources at an extraordinary and unreasonable cost … that will exacerbate affordability concerns for customers with no commensurate benefit.").

[14] North American Electric Reliability Corporation, 2024 Summer Reliability Assessment (May 2024), p. 40, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf.

[15] Energy Sys. Integration Grp., New Res. Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements (Mar. 2024), p. 2-3, available at https://www.esig.energy/wp-content/uploads/2024/03/ESIG-New-Criteria-Resource-Adequacy-report-2024.pdf.

[16] R.23-10-011, California Environmental Justice Alliance and Sierra Club Opening Comments on Track 2 Proposals and the Lole Study (August 9, 2024), p. 16-18.

[17] Energy Sys. Integration Grp., New Res. Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements (Mar. 2024), p. 9, available at https://www.esig.energy/wp-content/uploads/2024/03/ESIG-New-Criteria-Resource-Adequacy-report-2024.pdf.

Even though BTM solar and storage are generation resources, the RESOLVE and SERVM models do not consider BTM solar and storage as candidate resources, and thus overlook a critical resource that both increases reliability and decreases costs for all customers. The Commission also treats BTM storage differently than other resources, as it has not been assigned a qualifying capacity (QC) value. The PD closes the working group to update the LIP, but the PD should be revised to form a working group to determine the correct QC value for BTM storage.

A. The RESOLVE and SERVM Models Incorrectly Include BTM Solar as a Forecast, Rather than Optimizing BTM Solar Like All Other Generation Resources.

BTM solar produces electricity, like every other generation resource the Commission's modeling evaluates and includes. BTM solar plus storage can produce electricity over a broad period of the day, allowing BTM solar plus storage to enhance reliability, especially in transmission constrained areas or load pockets. But unlike all other generation sources, the RESOLVE model does not analyze BTM solar as a candidate resource. Instead, the RESOLVE and SERVM models incorporate BTM solar only as a "specified generation profile," or an immutable forecast value.[18] After RESOLVE modeling derives the capacity of candidate resources, candidate resources are then used as inputs into SERVM. SERVM, like RESOLVE, incorporates BTM solar only as a forecast.[19]

Including BTM solar as a candidate resource in its models would enable the Commission to determine whether additional need exists, especially in the local areas that the PD calls out as a matter of concern.[20] Including BTM solar like every other generation resource also would enable the Commission to assess the appropriate amount of BTM solar to add to the system to reduce greenhouse gas emissions or to improve reliability.[21]

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[18] *Ibid.*

[19] R.23-10-011, Proposed Inputs & Assumptions: SERVM 2024 Data Updates in Support of Resource Adequacy (RA) and Integrated Resource Planning (IRP), p. 13 ("The capacity of both baseline and candidate resources are inputs to SERVM…Candidate resources are selected using capacity expansion modeling such as RESOLVE or derived from IRPs and other resource projections.").

[20] PD, p. 36, *id.* at p. 38, *id.* at p. 64 (FOF 4).

[21] R.20-05-003, Inputs & Assumptions 2022-2023 Integrated Resource Planning (IRP) (October 2023), p. 54.

The Commission has acknowledged that RESOLVE fails to capture the transmission and distribution benefits of BTM customer-sited resources.[22] These benefits including avoiding the construction of expensive transmission lines,[23] which is not accounted for in the RA proceeding.

If RESOLVE and SERVM continue to limit BTM solar and fail to treat BTM solar generation as a candidate resource in their modeling inputs, the Commission will not be able to know, much less determine, the extent to which BTM solar installation enhances reliability and maximizes greenhouse gas reduction opportunities.

The PD should be revised to order the inclusion of BTM solar as a candidate resource in RESOLVE and SERVM, given the importance of GHG emissions reduction to lessen the predicted severity of climate change,[24] and the need to reduce ratepayer bills by avoiding the construction of expensive transmission lines.[25] The PD should be revised to value all the attributes that BTM solar plus storage provides to the system, to meet need, to ensure reliability and to reduce infrastructure costs.

B. The PD Should Address PCF's Proposal to Prioritize BTM Solar.

The PD recommends deferring consideration of CEJA and Sierra Club's proposal to restructure the CPE framework to close gas plants to the IRP proceeding.[26] CEJA and Sierra Club's proposal included a framework for the CPE that could be used to shut down gas plants and procure DER resources instead.[27]

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[22] *Ibid.*
[23] R.22-11-013, PCF-01, p. 11 ("DERs exist as the least-cost and most effective solution to the reliability need used to justify transmission projects, would potentially avoid the planning and construction of such transmission projects with the attendant reduction in ratepayer costs, and the attendant adverse environmental impacts.").
[24] The Washington Post, U.N. Says Only a 'Quantum Leap' Can Keep Global Climate Goals within Reach (October 24, 2024), available at https://www.washingtonpost.com/climate-environment/2024/10/24/global-warming-countries-un/.
[25] A.22-05-015, -016, Prepared Direct Testimony of Bill Powers, P.E. On Behalf of The Protect Our Communities Foundation (PCF-01), p. 2 ("Local SPS systems provide 100 percent clean power where the power is used, reduce congestion on the grid, and minimize the need for capital investments in new transmission projects justified on grid reliability purposes.").
[26] PD, p. 47.
[27] R.23-10-011, CEJA and Sierra Club Track 2 Proposals (June 14, 2024), p. 10.

DERs, including solar and storage on commercial buildings and parking lots, can be deployed faster than utility-scale resources, avoid land-use concerns, and save ratepayer costs.[28]

PCF agreed with CEJA and Sierra Club's proposal, but also argued that the Commission prioritize installing DER resources generally, outside of the CPE framework.[29] PCF proposed that the RA proceeding itself can be restructured to prioritize DER resources, for example, by prioritizing distributed solar and storage systems on warehouses and parking lots. The PD should be revised to consider both PCF's and CEJA and Sierra Club's proposals in this proceeding, rather than deferring consideration to the IRP proceeding, because DERs need to be prioritized as soon as possible, as an economically efficient and greenhouse gas reducing resource.

C. The PD Should Order a New Working Group to Include BTM Storage as Part of the Load Impact Protocols.

The PD declines to adopt a further working group process to improve the Load Impact Protocols.[30] Currently, the Load Impact Protocols grant a QC value to demand response,[31] so that it is on par with other resources, all of which have QC values.[32] The PD should be revised to form a new working group to develop Load Impact Protocols to develop a QC value for BTM solar and storage in Track 3 of this proceeding. The Commission has previously considered granting a QC value to BTM storage and proposed that a working group could develop a proposal to establish a QC value for BTM resources.[33]

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[28] A.22-05-015, -016, Prepared Direct Testimony of Bill Powers, P.E. On Behalf of The Protect Our Communities Foundation (PCF-01), p. 2 ("Local SPS systems provide 100 percent clean power where the power is used, reduce congestion on the grid, and minimize the need for capital investments in new transmission projects justified on grid reliability purposes."); Solar Energy Industries Association, Development Timeline for Utility-Scale Solar Power Plant, https://www.seia.org/research-resources/development-timeline-utility-scale-solar-power-plant [as of February 2, 2024] (estimating 6 years for the development of a 250 MW utility-scale solar power plant, with four years allocated to development, and two to construction); Renogy, Commercial Solar Panel Installation (February 9, 2023), https://www.renogy.com/blog/commercial-solar-panel-installation/ [as of February 4, 2024] ("large commercial installations can take anywhere from a week to several months.").

[29] R.23-10-011, The Protect Our Communities Foundation Comments on Track 2 Proposals and LOLE Study (August 9, 2024), p. 9-11.

[30] PD, p. 61.

[31] Commission, Load Impact Protocols, available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-load-impact-protocols [as of November 16, 2024].

[32] Commission, 2020 Qualifying Capacity Methodology Manual (November 2020), p. 5-6.

[33] D.21-06-029, Decision Adopting Local Capacity Obligations for 2022-2024, Flexible Capacity Obligations for 2022, and Refinements to the Resource Adequacy Program (June 25, 2021), p. 55

The QC value would provide compensation for BTM resources' ability to export to the grid[34] and would put BTM storage on par with all the other resources for which the Commission and the CAISO have already developed QC values.[35]

IV. THE COMMISSION SHOULD REJECT THE UCAP PROPOSAL AND MAINTAIN ITS INDEPENDENT AUTHORITY TO OVERSEE AND PREVENT OUTAGES.

The PD recommends that the Commission submit a revised UCAP proposal in Track 3 of this proceeding. However, the PD fails to mention how the Commission will ensure that generator owners and operators maintain optimal maintenance practices[36] or take the actions necessary to ensure that their plants can produce during tight supply conditions. Public Utilities Code section 761.3 and G.O. 167 require that the Commission actively oversees and reports on the maintenance and operation of California power plants to ensure availability and reliability.[37] To comply with its oversight responsibilities, the Commission should not assume forced outage rates are appropriate without analyzing whether such outages can be minimized by better maintenance of the generation facilities located in California. The PD should be revised to reject the UCAP proposal until the Commission can ensure that the most effective and thorough maintenance and operations procedures are and have been followed by all California generation facilities.

If the Commission approves a UCAP mechanism, in order to comply with the law, PCF agrees with the CAISO DMM that any mechanism must distinguish outages on an individual plant level and should assess whether each and every outage was caused by issues within the plant owners' or scheduling coordinator's control or whether the outage resulted from system-

("Parties may undertake a working group to develop a proposal that addresses the concerns raised by the Commission here.").

[34] R.21-10-002, Joint DER Parties Implementation Track – Phase 2 Proposal (January 21, 2022), p. 2.

[35] D.22-06-050, p. 45 (IFOM resources have QC values: "the Commission considered a proposal to give behind-the-meter (BTM) solar-plus-storage (hybrid) resources a QC value equivalent to in-front-of-the-meter (IFOM) resources.").

[36] R.20-11-003, Prepared Reply Testimony of Bill Powers, P.E. on Behalf of The Protect Our Communities Foundation (January 19, 2021), p. 7 ("Moreover, the forced outage rate can be further reduced by requiring best maintenance practices in the CAISO control area and not simply by assuming that national average outage rates are sufficient.").

[37] Pub. Util. Code, § 761.3, subd. (a) ("[T]he commission shall implement and enforce standards for the maintenance and operation of facilities for the generation and storage of electricity owned by an electrical corporation or located in the state to ensure their reliable operation."); G.O. 167.

wide problems for which the individual plant owner should not be held responsible.[38] PCF agrees with the DMM that "forced outages should be separated into two categories for grid planning and management: (1) forced outages under the control of the scheduling coordinator and asset owner, and (2) forced outages for system or grid conditions out of their control. Determining the reach for each plant outage and incorporating resource-level UCAP accounting and regular NQC updating through the UCAP framework, will incentivize generators to reduce all unnecessary forced outages."[39] As PCF has demonstrated, the August 2020 blackouts were caused in part by specific power plants failing to produce when called.[40] Thus, any UCAP proposal must assess and evaluate the circumstances of *each* outage as part of the Commission's responsibilities under Section 761.3 and G.O. 167 and must require all generation owners properly to maintain and operate each generation resource located in California.

As the PD recognizes, it "may not be feasible for a final UCAP methodology to be at a resource-specific level unless a procedure is developed to correct anomalous or missing data from specific plants"[41] but the PD then draws the wrong conclusion from this lack of data that "additional class groupings should be considered."[42] As the DMM details, it remains imperative that the Commission assess each generation facility's conduct individually as group level data can obscure individual plant inappropriate conduct. Thus, PCF agrees that the Commission should direct Energy Division to find and use complete and accurate plant-level data on outages and curtailments, both to develop a workable UCAP and to fulfill its statutory requirements to inspect and ensure proper generation plant maintenance and operations.

The PD closes its working group on UCAP issues in deference to the CAISO's ongoing process: "Due to the work already underway towards a proposed UCAP methodology, an additional working group process is unnecessary; rather, we encourage parties to participate in

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[38] R.23-10-011, Comments on Track 1 Proposals by The Department of Market Monitoring of the California Independent System Operator Corporation, (March 8, 2024) p. 3.
[39] R.23-10-011, Comments on Track 1 Proposals by The Department of Market Monitoring of the California Independent System Operator Corporation, (March 8, 2024) p. 3.
[40] R.20-11-003, Prepared Reply Testimony of Bill Powers, P.E. on Behalf of The Protect Our Communities Foundation (January 19, 2021), p. 2 ("My review of the data reveals that three of nine Southern California OTC units, equaling 1,256 MW of 3,733 MW of the total OTC net qualifying capacity (NQC), were unavailable when the first rolling blackout was initiated at 6:38 pm on August 14, 2020.").
[41] PD, p. 23.
[42] PD, p. 23.

CAISO's stakeholder process and submit proposals or evaluate Energy Division's proposal in Track 3 of the proceeding."[43] In making this recommendation, the Commission undercuts its own regulations contained in GO 167 and disables both the CAISO (the entity promulgating outage protocols under Section 761.3) and itself (the enforcement entity under Section 761.3.) The Commission should not direct parties to participate in CAISO stakeholder processes in lieu of public Commission proceedings because the CAISO provides inadequate public participation access and need not consider or address public party comments as the Commission must do. Moreover, the Commission must comply with its independent statutory mandates to ensure that thorough maintenance and operations practices are followed in all generation facilities located in California.

Additionally, the PD proposes that the Commission should "harmonize" with the CAISO to identify data and analyze data.[44] While coordination and the sharing of data and information remain necessary for both the CAISO[45] and the Commission to comply with their statutory mandates, the Commission should make certain that its staff does not defer to the CAISO. As explained above, the Commission retains responsibilities to ratepayers[46] and to regulate the Utilities[47] which the CAISO does not. Accordingly, the Commission should ensure that it does not defer to the CAISO as it works in parallel with the CAISO to comply with the mandates of Section 761.3 and to ensure reliability at a reasonable cost.

V. THE COMMISSION SHOULD NOT APPROVE ANY CPE AUTHORIZATION THAT INCLUDES OPPORTUNITY COSTS OR THAT EXCEED GOING FORWARD FIXED COSTS.

The Commission should reject any attempt to authorize the CPE to accept or offer bids for back-up or RA generation resources that exceed any generation facility's actual Going Forward Fixed Costs (GFFC) and should reject any proposal to set a CPE soft offer proposal at the Capacity Procurement Mechanism (CPM) cost plus RA penalties.

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[43] PD, p. 22.
[44] PD, p. 22.
[45] Pub. Util. Code, § 761.3, subd. (e) sets forth the CAISO's duties to maintain outage data and reasons and to provide that information publicly and to the Commission.
[46] Pub. Util. Code, § 747 ("It is the intent of the Legislature that the commission reduce rates for electricity and natural gas to the lowest amount possible.").
[47] Pub. Util. Code, § 454.52, subd. (a)(1)(C) ("Enable each electrical corporation to fulfill its obligation to serve its customers at just and reasonable rates."). Section 747, *supra* n 3, imposes a statutory mandate to reduce ratepayer costs on the Commission specifically.

The PD appropriately rejects any authority for the CPE to bid at a price that incorporates amorphous opportunity costs, which would result in even higher unwarranted ratepayer costs. The PD should be revised to authorize CPE purchases only at prices that relate to a generation facility's GFFC.

As a threshold matter, the CPM price cap results in much higher costs[48] for LSEs and ratepayers than procurement purchased in an appropriately functioning electricity market, as the ISO triggers CPM procurement authorization at times of emergency. The CAISO's DMM's own analysis "provides strong evidence that the annual fixed O&M cost estimates produced by the CEC, and used by the CAISO to set the CPM soft-offer cap, significantly overstate the GFFC of a combined cycle gas unit."[49] As the CAISO's DMM has explained, "the CPM soft cap is based on a significantly inflated estimate of annual going forward fixed costs. . ."[50] Thus, the CPM electricity bid cap should never be used as a reference price for any Commission price authorization, as the CPM represents extraordinary pricing allowed during emergency situations. To do so would cause the Commission to violate Section 451's requirement to allow only just and reasonable rates.[51]

If the Commission allows bids to be accepted by the CPE above the so-called soft-offer price cap, it will raise prices and increase electricity rates. The CAISO DMM has repeatedly warned the Commission that authorizing a CPE to bid above the GFFC "encourage sellers of local RA to exert local market power. This concern is especially acute with an administratively-set price that would send a market participant's information or signals that could allow sellers to bid their capacity above their true annual GFFC."[52]

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[48] As the CAISO's Department of Market Monitoring has explained, "Since the CPM soft offer cap was established in 2014, the ISO's policy has been to set the cap based in part on an estimate of the annual going forward fixed costs of a typical new gas-fired unit plus a 20 percent adder." *See* DMM Memo to the CAISO Board of Governors, Sept. 13, 2023, p. 1, available at: https://www.caiso.com/Documents/DepartmentofMarketMonitoringComments-CapacityProcurementMechanismEnhancementsTrack2-Memo-Sep2023_final.pdf.

[49] R.23-10-011, Comments on Track 1 Proposals By The Department of Market Monitoring of the California Independent System Operator Corporation, (March 8, 2024) p. 12.

[50] DMM Memo to the CA ISO Board of Governors, Sept. 13, 2023, p. 2, available at: https://www.caiso.com/Documents/DepartmentofMarketMonitoringComments-CapacityProcurementMechanismEnhancementsTrack2-Memo-Sep2023_final.pdf.

[51] Pub. Util Code, § 451.

[52] R.23-10-011, Comments on Track 1 Proposals By The Department of Market Monitoring of the California Independent System Operator Corporation, (March 8, 2024) p. 12.

In this Rulemaking, the DMM urges the Commission to "consider local market power" when assessing the CPE's authority to bid in the CAISO's markets. As the DMM has informed the Commission, if it allows the CPE to use the CPM or bid at or above the CAISO's soft cap level, the "DMM's 2023 annual report shows that in 2023, there were five local areas that had pivotal suppliers of local RA capacity. Pivotal suppliers in these areas could potentially exert market power on the sale of local RA capacity."[53]

The DMM's detailed analyses of the limited number of local RA suppliers, resulting in five local areas of potential supply constraints, provides yet another reason for the Commission to include BTM solar plus storage resources in its RESOLVE and SERVM modeling. Evaluating BTM solar as a forecast rather than including it as an available source of capacity in each local area further enables suppliers in locally constrained areas to exert market power – driving up consumer prices because of Commission modeling deficiencies. As PCF has repeatedly warned, allowing the RESOLVE model to employ assumptions that are not consistent with the facts will only raise costs without providing greater reliability or safety.

A recent D.C. Circuit opinion further supports the Commission's rejection of any CPE procurement authority based on the CAISO's soft cap construct. In *Shell Energy North America v. FERC,* the D.C. Circuit Court of Appeals overruled FERC's imposition of penalties for sellers that exceeded the CAISO's so-called soft caps during the August 2020 blackouts.[54] FERC had agreed with the Commission and Southern California Edison that "some sellers had failed to justify their above-cap sales and ordered partial refunds."[55] The D.C. Circuit effectively eliminated FERC's enforcement of any "soft" price cap when it held that contracts above capped contract prices were formed through "arms-length, bilateral negotiation"[56] and thus were reasonable. Especially now that the D.C. Circuit has at least limited, if not eliminated, FERC's ability to protect California consumers from price gouging in the CAISO electricity markets, it falls to the Commission to take every action it can to protect California consumers from excess prices in the CAISO markets.

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[53] R.23-10-011, Comments on Track 2 Proposals by the Department of Market Monitoring of the California Independent System Operation Corporation, (August 9, 2024) p. 3.
[54] *Shell Energy North America v. Federal Energy Regulatory Commission* (D.C.Cir. 2024) 107 F. 4th 981, 985 (hereafter *Shell Energy*).
[55] *Shell Energy*, 107 F.4th at 983.
[56] *Shell Energy* 107 F. 4th at 985.

Those actions should include limiting, in this PD, any CPE bidding or procurement authority to the GFFC costs of generation, to avoid creating additional price gouging opportunities in the CAISO market.

The Commission should also consider recommending to the CAISO that it file a tariff at FERC to reinstate the Must Offer Obligation that expired at the end of 2016.[57] The DMM's comments in Track 1 raise the need to require a must offer obligation with respect to RA resources in the real time market:"[I]t could be important to maintain a real-time must-offer obligation for RA imports, to ensure these imports are available when real-time market conditions are much different than in the day-ahead market."[58] PCF proposes that the striking price increases experienced in the CAISO's market since 2020 demonstrate that the Commission should include in Track 3 whether to recommend a renewed must offer obligation in the CAISO's markets to assure adequate reliability and to reduce the exorbitant procurement costs that California LSEs increasingly face.

VI. CONCLUSION

PCF requests that the Commission adopt the proposed changes to the PD that it details in the attached Appendix.

Sincerely,

/s/ Andrea White
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[57] At the end of 2016, FERC eliminated the west-wide Must Offer Obligation (MOO) originally put in place in 2001 to quell the "market dysfunction" of the California Energy Crisis (157 FERC P. 61,051, Oct. 21, 2016). FERC's rationale did not take into account the existence of unmitigated market power or opportunities for market manipulation, as the DMM now newly details.

[58] R.23-10-011, Comments on Track 1 Proposals By The Department of Market Monitoring of the California Independent System Operator Corporation, (March 8, 2024) p. 11.

APPENDIX

Findings of Fact

1. Additional vetting and further analysis of Energy Division's revised PRM analysis is needed. The data gathering and reconciliation for the inputs and assumptions that underlie the LOLE study are time-consuming and resource intensive.

2. Due to a lack of participation by LSEs in the non-compensated self-showing option, CPEs do not have access to critical information before initiating the CPE solicitation as to what local resources are under contract by LSEs, what the most effective local resources are to secure, and what the true needs are in designated local areas.

3. The current non-compensated self-showing construct has been ineffective, as there is no binding commitment on LSEs to self-show and LSEs have elected not to self-show despite numerous attempts to incentivize participation.

4. PG&E's proposal to eliminate and replace the non-compensated self-showing option will allow CPEs to better fulfill the role designated to them in D.20-06-002: to secure a portfolio of the most effective local resources, use purchasing power in constrained local areas, mitigate the need for backstop procurement, and ensure a least cost solution for customers and equitable cost allocation.

5. Locking in CPE allocations more than one year in advance, as compared to two months, would be beneficial in that it would give LSEs more time for procurement and more time to negotiate favorable RA contracts on behalf of customers.

6. Locking in CPE allocations earlier will increase certainty for LSEs to understand how much system and flexible RA they may need to procure.

7. PG&E's proposed expansion of the publication of CPE procurement information would provide additional granular information on the CPEs' procurement process that could benefit the CPE framework by giving stakeholders more insight into the procurement process.

8. The recommendations from the LIP Working Group Report, with some exceptions, represent consensus positions from a broad range of parties.

9. BTM solar and storage are generation resources. It is appropriate to revise SERVM to consider BTM solar as a candidate resource, rather than incorporated only as a forecast.

10. BTM solar and storage and distributed solar are low cost and greenhouse gas reducing resources.

11. BTM solar and storage is a generation resource and it is appropriate to determine a QC value for BTM solar and storage.

12. The UCAP Proposal does not consider whether generators are following optimal maintenance practices and potentially cedes too much control to the CAISO.

13. The soft-offer price cap proposal is not appropriate. It is appropriate for the CPE to reject any offer bids for back-up or RA generation resources that exceed any generation facility's actual Going Forward Fixed Costs (GFFC).

14. Track 3 should consider the appropriate GFFC and any proposed profit levels to set in this proceeding's determination of the appropriate bid and price levels at which to authorize the CPE to use when bidding in the CAISO markets.

Conclusions of Law

1. Energy Division should be authorized to undertake a further revision of the 2026 PRM analysis to correct identified errors and distribute it to the service list in December 2024.

2. Consideration of the revised PRM analysis and the 2026 PRM should be deferred to Track 3 of this proceeding.

3. It is more realistic and reasonable for Energy Division Staff to update the RA LOLE study every two years for consideration in the RA proceeding.

4. PG&E's proposal to eliminate the non-compensated self-showing option may provide a more reliable, efficient way for the CPEs to obtain information about what local resources are under contract by LSEs. PG&E's proposal to eliminate the non-compensated self-showing option should be adopted, with modifications.

5. CalCCA's proposal to lock CPE allocations to LSEs one year in advance is reasonable and should be adopted, with modifications, on an interim basis to be reevaluated at the end of 2027.

6. PG&E's proposal to expand the publication of CPE procurement information is reasonable and should be adopted.

7. The recommendations from the LIP Working Group Report, with some exceptions, are reasonable and should be adopted.

8. All assigned Commissioner and assigned Administrative Law Judge rulings should be affirmed.

9. SERVM should be revised to consider BTM solar as a candidate resource, rather than incorporated as a forecast.

10. The Commission should prioritize installing BTM solar and storage and distributed solar in the RA proceedings.

11. The Commission should authorize a working group to develop a QC value for BTM solar and storage.

12. The UCAP Proposal does not consider whether generators are following optimal maintenance practices, cedes too much control to the CAISO, and should be denied.

13. Section 761.3 and G.O. 167 requires the Commission to investigate generation facility outages located in California and to enforce the maintenance and operations standards contained in G.O. 167. As part of that enforcement, the Commission's Energy Division should identify or develop comprehensive and accurate data about each plant outage and whether the plant owner, operator, or scheduling coordinator bears responsibility for that outage.

14. The CPE should reject offer bids for back-up or RA generation resources that exceed any generation facility's actual Going Forward Fixed Costs (GFFC).

15. ~~9.~~ All pending motions should be denied.